WATAYNIKANEYAP POWER LP

Responses to Interrogatories from Hydro One Remotes

Issue: Reliability

HORCI - 1

Reference: Exhibit C, Tab 1, Schedule 1 (page 7) notes that, “issues of capacity and reliability are intertwined,” and describes an emergency in Wawakapewin.

Request:

a) Was the described emergency due to generating capacity constraints? Please explain.

Response:

WPLP understands that the generator failure in Wawakapewin was related to equipment failure. WPLP further understands that the generator, which failed, had been operating for an extended period beyond its normal operating capacity and that this may have contributed to the failure. The example of the Wawakapewin generator failure was meant to provide a real and recent example of how generator failure (in this case, in a community served by an IPA and not by HORCI) can lead to declarations of emergencies within a community, and how the response to such events can be affected by weather and accessibility.

HORCI - 2

Reference: Exhibit C, Tab 1, Schedule 1 (page 9) states that, "each of the remote communities faces severe limitations on its supply capacity and the ability to increase this capacity in a timely manner."

Request:

a) Please provide a list of the communities that are currently in supply capacity restrictions.

b) Please provide a forecast of the communities that will be in capacity restriction by 2024.

Response:

a) The following is a list of currently known load restrictions, as confirmed by Indigenous Services Canada ("ISC"):

- Pikangikum (until grid connection)
- Sandy Lake (new as of April 2018)
- Kitchenuhmaykoosib Inninuwug (expected to be removed upon completion of the 25 kV grid tie project between KI and Wapekeka, which is imminent)

In providing this information, ISC has clarified that IPAs are not required to report on their supply capacity, and therefore the presence of load restrictions, and whether or not the IPAs restrict new connections as they approach generator capacity, is difficult to track.

Based on discussions with the connecting communities, WPLP further understands that Muskrat Dam First Nation (currently served by an IPA) is subject to load restrictions.

To further clarify, the above statement from the Application was not meant to indicate that each community faces a complete restriction on new connections today, but rather that supply from diesel generators can result in a cycle where, as the load approaches the generation capacity in any given community, that community will be faced with limitations on new connections, and that the ability to increase capacity in a timely manner is generally beyond the community's control.

b) WPLP is not involved in the operational decision making related to capacity restrictions, nor is it aware of any interim solutions being considered to alleviate current or forecast capacity restrictions in any given community. As such, WPLP is not in a position to forecast future restrictions.

HORCI - 3

Reference: Exhibit C, Tab 5, Schedule 1, (pages 7 & 8). The IESO supported scope for the project suggests that WPLP "facilitate the arrangement of backup electricity supply resources for connecting communities where: such facilities do not already exist, other arrangements have not been made, or the community has not specifically requested an exemption."

Request:

a) Please outline in detail the progress made to date on backup supply.

b) Do all of the communities have functional Emergency Preparedness Plans ("EPPs")? Please list those that do not have functioning EPPs.

c) Have any communities requested an exemption from backup supply?

d) Have consultations with the communities taken place, including the expected hours of loss of supply outages? Please provide documentation of these consultations, including any presentations made and any minutes of the discussions.

Response:

a) WPLP engaged BBA in mid-2017 to undertake an analysis of possible options and costs related to backup supply to the 16 communities to be connected to the Remote Connection Lines. The scope of this effort included estimating the expected frequency and duration of outages to the transmission system, analyzing baseline data in terms of load, capacity of existing diesel generators, fuel storage capacity and critical infrastructure in the communities. BBA's scope also included the consideration of backup solutions in other jurisdictions, as well as the use of renewable and emerging technologies. BBA's final report was delivered in May 2018 and, as described in the application, was provided to a number of stakeholders. Please see the response to Board Staff IR 16 (a) for a discussion of current status and outlook with respect to backup power.

b) ISC has provided the following information with respect to the status of emergency plans for each community:

Status of Emergency Plans

Community	Emergency Plan in Place	Dated
Bearskin Lake	Yes	2012
Big Trout Lake	Yes, in draft	>10 yrs
Deer Lake	Yes, Requires Updating	>10 yrs
Kasabonika	Yes	2011
Keewaywin	Unknown, Plan not Shared with ISC	nil
Kingfisher Lake	Yes	2014
Muskrat Dam	Yes, Requires Updating	>10 yrs
North Caribou Lake	Yes, Requires Updating	>10 yrs
North Spirit Lake	No	nil
Pikangikum	Yes, Requires Updating	>10 yrs
Poplar Hill	Yes, Requires Updating	>10 yrs
Sachigo Lake	Yes	2011
Sandy Lake	Yes	2012
Wapekeka	Yes	2014
Wawakapewin	Yes	2014
Wunnumin Lake	No	nil

Source: ISC Emergency and Issues Management Advisor - October 30, 2018 (CIDM #880429)

c) WPLP's understanding is that no communities have requested an exemption from backup supply.

d) WPLP, with assistance from Opiikapawiin Services Limited Partnership (OSLP),[1] has facilitated discussion on the topic of backup power (among other agenda items) at recent community meetings. A copy of the presentation related to backup power is provided as Schedule HORCI – 3(d). Slide 3 of that presentation specifically references that "Transmission Line outage estimates per community range from 0.75% - 1.65% of the year", with a note that this estimate does not include local distribution outages.

[1] OSLP is a company that is indirectly owned by the 22 Participating First Nations, and which provides community engagement, communications, First Nations participation and training services to WPLP.

HORCI - 4

Reference: IESO Report: *Draft Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario*[2], dated August 21, 2014.

Preamble: On page 112 of the Draft Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario' (the "Report") issued on August 21, 2014 by the Ontario Power Authority (now the IESO), for the Northwest Ontario First Nation Transmission Planning Committee, it provides expected outages by community as shown below.

Extract of Table 25 from the IESO Report: *Draft Technical Report and Business*

Case for the Connection of Remote First Nation Communities in Northwest Ontario

Table 25: Expected Outage Time Post-Connection by Community

	Planned Outages			Forced Outages				Total Outages	
Community	Planned Outages/year	Planned Outage time (hr/yr)	Percent of time	Momentary Forced Outages/year	Sustained Forced Outages/year	Sustained Forced Outage time (hr/yr)	Percent of time	Total Outage Time (hr/yr)	Total percent of time
Deer Lake	6	81	0.9%	6	17	38	0.4%	119.15	1.36%
North Spirit Lake	5	69	0.8%	5	13	29	0.3%	97.60	1.11%
Poplar Hill	4	54	0.6%	4	11	26	0.3%	79.81	0.91%
Pikanjikum	4	49	0.6%	4	10	22	0.3%	70.86	0.81%
Kee-way-win and Koocheching	7	82	0.9%	6	16	36	0.4%	118.26	1.35%
Sandy Lake	7	85	1.0%	7	17	38	0.4%	122.24	1.40%
Kingfisher Lake	6	79	0.9%	6	18	42	0.5%	120.81	1.38%
Wawakepewin	8	97	1.1%	6	25	56	0.6%	153.06	1.75%
Kasabonika Lake	8	106	1.2%	7	28	63	0.7%	169.30	1.93%
Wunnumin Lake	7	86	1.0%	6	21	48	0.5%	133.84	1.53%
Wapekeka	9	112	1.3%	7	29	67	0.8%	178.57	2.04%
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	9	115	1.3%	7	30	69	0.8%	183.22	2.09%
Bearskin Lake	8	97	1.1%	7	23	52	0.6%	148.76	1.70%
Muskrat Dam	6	81	0.9%	6	20	45	0.5%	126.21	1.44%
Weagamow (North Caribou Lake)	6	70	0.8%	5	16	37	0.4%	106.66	1.22%
Sachigo Lake	8	97	1.1%	7	23	52	0.6%	148.48	1.70%
Eabametoong (Fort Hope)	7	86	1.0%	6	19	44	0.5%	130.32	1.49%
Landsdowne House (Neskantaga)	6	77	0.9%	5	18	42	0.5%	118.92	1.36%
Webequie	7	92	1.1%	7	21	47	0.5%	139.12	1.59%
Nibinamik (Summer Beaver)	8	101	1.2%	7	24	56	0.6%	156.52	1.79%
Marten Falls	8	99	1.1%	7	25	57	0.7%	156.37	1.79%

Source: OPA, IESO

[2] Link to Report on IESO Website: http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/remote-community-connection/OPA technical-report-2014-08-21.pdf?la=en

On Page 110 and 111 the Report notes that, “the expected outage duration for transmission supply alone is estimated to be an improvement for IPA communities but not generally for the average HIRC community”. The IESO supported scope as described in Exhibit C, Tab 5, Schedule 1, indicates that backup diesel generation would be needed in the communities.

Request:

a) The above table shows supply-related outages that range from about 70 hours per year to about 179 hours per year, depending on proximity to the grid. Exhibit C, Tab 5, Schedule 1 (page 7) references a BBA report that updates expected supply related (transmission) outages in the communities. Please provide a copy of that report.

b) Has WPLP provided a copy of the BBA report with the expected transmission outages and backup options to the communities?

c) Has WPLP or any of its partners initiated any discussions with the communities regarding backup power? If so, please provide a summary of the discussions including comments from communities.

Response:

a) A copy of the BBA report is attached as Schedule HORCI 4(a). In addition, WPLP notes that the IESO has confirmed its methodology in producing the table above as follows:

> *Actual outage frequency and duration data for similar northwest radial 115 kV circuits, E4D, M3E, E1C and A4L, from 1990 to 2008 were used. These were averaged per kilometre of exposure of each line and applied to the line length estimates from the 2014 Remote Community Connection Plan to establish expected outage frequency and duration for each community.*

The methodology used by BBA to update the forecasted outage frequency and duration by community is described in detail in the BBA report.

b) Key findings of the BBA report, including forecasted outage durations and backup supply options, have been communicated to the communities through the delivery of a presentation in community readiness meetings, as described in response to HORCI IR 3(d). The presentation also provided background information to each of the communities with respect to backup power generally, and information on next steps in relation to backup power. Complete copies of the BBA report were made available to participants in each of these meetings. OSLP on behalf of WPLP is currently in the process of distributing a hard copy of the BBA report to the Chief and Council of each First Nation Community.

c) Please see response to HORCI IR 3 (d).

HORCI - 5

Reference: Table 2-13 below was filed in Hydro One Remotes' Distribution System Plan ("DSP") as part of its 2018 revenue requirement application (EB-2017-0051) at Exhibit B, Tab 1, Schedule 1, Section 2.3.4.2, Table 2-13, page 51.

The table provides actual annual percentage of minutes of supply related outages across all the communities Remotes currently serves from 2013 to 2016.

Extract of Table from Remotes' 2018-2022 Distribution System Plan

Table 2-13: Percentage of Generation Availability 2013-2016

Year	**2013**	**2014**	**2015**	**2016**
Generation Availability	99.86%	99.97%	99.97%	99.96%

Preamble: Based on the information from Remote's 2018-22 DSP, Table 2-13 (provided above), the annual supply outage as a percentage of total time, and average annual hours of supply outages by Community in Remotes service territory is as follows:

Table 1

Remote Communities Actual Annual Supply Data - 2013 to 2016

Year	**2013**	**2014**	**2015**	**2016**	**Row**
Total Time	100.00%	100.00%	100.00%	100.00%	A
Generation Availability all Stations	99.86%	99.97%	99.97%	99.96%	B
Supply Outage as a Percentage of time	0.14%	0.03%	0.03%	0.04%	C = A - B
Total Hours per Year	8,760	8,760	8,760	8,760	D= 365 (days) 24 hours
Average Hours of Supply Outages by Community	**12.26**	**2.63**	**2.63**	**3.50**	E = C x D

Request:

a) In its Report the OPA/IESO estimates a range of 70-179 hours[3] of supply related (transmission) outages per individual community following connection, compared to an annual average range of 2.63 hours to 12.26 hours (Table 1, Row E, above) of supply related outages currently experienced, per individual community. Based on the estimates of supply related outages in the OPA/IESO (as provided in Interrogatory 4 reference material above), does WPLP agree that backup generation is required following grid connections to provide service reliability, that would, on average, be equal to what these communities currently experience?

b) Currently, Hydro One Remotes is considering retaining the generation assets to provide backup generation in the communities it currently serves and has also been working on a backup study for INAC (ISC) and one of WPLP's partners, Opiikapawiin Services Limited Partnership (OSLP) related to all of the connecting communities. Based on the IESO forecast for the communities Hydro One Remotes currently serves, and on station design, capacity is expected to be sufficient to supply backup power to the communities for at least 20 years, with minor capital upgrades and with small quantities of fuel kept at the community. Would Watay support Hydro One Remotes in including these costs in Remotes' own revenue requirement?

c) Does WPLP or its partners have any information about the current hours of loss of supply outages in the IPA communities?

Response:

a) WPLP agrees with the above statement. Please also see response to HORCI IR 4 (a).

b) To clarify, whereas the question refers to OSLP as being one of WPLP's partners, this is not correct. WPLP's partners are Fortis (WP) GP Inc. on behalf of Fortis (WP) LP and 2472881 Ontario Limited as the general partner on behalf of First Nation LP. First Nation LP and its general partner are wholly owned by the 22 Participating First Nations in equal shares. The Participating First Nations also indirectly own OSLP, but not through First Nation LP or its general partner.

   In response to the question asked, provided that the relevant First Nation communities and other stakeholders are in general agreement on proceeding with this solution, WPLP would support HORCI in including these costs (net of any government funding received) in its own revenue requirement.

[3] As shown in Table 25 (provided in Remote's Interrogatory # 4 (above), as extracted from the IESO Report: *Draft Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario*, found in the table's column titled "Total Outage Time (hrs/yr)".

c) WPLP does not have this information, nor do any of WPLP's partners. Further, ISC confirmed that the IPAs are not required to report this information.

HORCI - 6

Reference: Exhibit C, Tab 5, Schedule 1, (page 9) in reference to the IESO scope.

Request:

a) What are the estimated line losses on the Remote Connection Lines?

b) Will the cost of line losses on the Remote Connection Lines be recovered through the IESO's uplift charges and recovered from all transmission customers (as per current practice)? What are the estimated line losses by community?

Response:

a) The total estimated system losses for WPLP's transmission system, as determined by WPLP's consultant BBA during the reactive power optimization analysis that was completed during the SIA process, are provided in the tables below. Please note that the estimated losses for the Pickle Lake portion of the project include both the Line to Pickle Lake and the Pickle Lake Remote Connection Lines. WPLP does not have and is not able to provide the estimated system losses that are specific to the Pickle Lake Remote Connection Lines.

Pickle Lake System Losses (% of total load) (Line to Pickle Lake and Pickle Lake Remote Connection Lines)	
Year	**System Losses (%)**
2025	13.3
2030	12.1
2035	11.3
2040	11.0
2045	11.2
2050	11.9
2055	13.3/11.1[4]
2060	12.5[4]

Red Lake Remote Connection Lines System Losses (% of total load)	
Year	**System Losses (%)**
2025	6.4
2030	6.4

[4] The decrease in losses in the 2055-2060 period considers that the first 115 kV line segment north of Pickle Lake may need to be twinned in approximately 2055 for technical performance reasons.

2035	6.4
2040	6.7
2045	7.4
2050	8.3
2055	9.9/7.3[5]
2060	8.5[5]

b) IESO has confirmed that, assuming WPLP's facilities become part of the IESO-controlled grid and that WPLP becomes a registered market participant, then any losses on the IESO-controlled grid (i.e. losses upstream of defined metering points) would be considered transmission system losses included in the uplift charges recovered from all transmission customers. Losses downstream of the defined metering points would not be captured in the uplift charges, and would instead be the responsibility of the load customer, which would be HORCI in the case of the 16 First Nation communities. Losses downstream of the defined metering points would generally include losses on facilities operating at less than 50 kV and transformer losses in any 115/25 kV or 115/44/25 kV transformer.

Per-community losses are not currently available, and the losses indicated in part (a), above, are at the level of granularity available at this time. Per-community losses will be determined during the course of registering each wholesale metering point with the IESO.

[5] The decrease in losses in the 2055-2060 period considers that the first 115 kV line segment north of Red Lake may need to be twinned in approximately 2055 for technical performance reasons.

Issue: Operations, Access and Community Readiness

HORCI - 7

Reference: Exhibit C, Tab 1, Schedule 1 (page 6) estimates a combined on-reserve registered population of approximately 14,000.

Request:

a) Please provide the source for this estimate.

b) Please provide a breakdown of the population by community.

c) Please provide an estimate of the unregistered population residing in the communities, including the teachers, nurses and others residing in the communities referenced in the exhibit.

d) Does Watay have an estimate of the number of distribution customers (i.e. entities that receive an electricity bill) in each community? If so, please provide.

Response:

a) The source for this estimate is "Indigenous and Northern Affairs Canada - First Nation Profiles - Registered Population" (Total of 'On Own Reserve') (http://fnp-ppn.aandc-aadnc.gc.ca/fnp/Main/Search/SearchFN.aspx?lang=eng) Accessed May 11, 2018

b) Please see the following table.

Cluster	Community	Population (Registered On Own Reserve)
Red Lake Cluster	Deer Lake	1086
	North Spirit Lake	439
	Poplar Hill	634
	Pikangikum	2,828
	Keewaywin and Koocheching	476
	Sandy Lake	2,642
	Red Lake Total	***8,105***
Pickle Lake Cluster	Kingfisher Lake	550
	Wawakepewin	40

	Kasabonika Lake	1,093
	Wunnumin Lake	575
	Wapekeka	470
	Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	1,156
	Bearskin Lake	482
	Muskrat Dam	214
	Weagamow (North Caribou Lake)	854
	Sachigo Lake	524
	Pickle Lake Total	***5,958***
TOTAL		**14,063**

c) WPLP is not in a position to provide, and has not been able to obtain, an estimate of the unregistered populations residing in the communities.

d) WPLP does not currently have this information for the IPA communities, and expects that detailed customer lists will be compiled during the process of transferring to HORCI. WPLP does not currently have this information for the HORCI communities, but expects that HORCI has this information for the communities that it currently serves.

HORCI - 8

Reference: Exhibit C, Tab 6, Schedule 1 (pages 2 & 3) - Community Readiness. References made outlining Hydro One Remotes' obligations to ensure each of its distribution systems is designed, maintained and operated in compliance with O.Reg. 22/04 (Electrical Distribution Safety).

Preamble: Hydro One Remotes designs, maintains and operates its distribution systems in compliance with the O.Reg. 22.04. Hydro One Remotes anticipates that all of the distribution systems will need to be upgraded as a consequence of grid connection to meet IESO market rules and settlement requirements. Hydro One Remotes has budgeted costs for wholesale metering, to facilitate the community distribution system connections as follows:

Table 2
Cost Budgeted by Remotes to Connect Community Distribution Systems to Project Lines

Distribution System / Community	Estimated Cost ($)	Estimated In-Service Year
Pikangikum	370,000	2018
Poplar Hill, Deer Lake, Muskrat Dam, Kingfisher, North Caribou	1,855,000	2021
Sachigo, Bearskin, Wawakepewin	1,113,000	2022
North Spirit, Sandy Lake, Keewaywin, Wunnumin, Wapekeka, Big Trout, Kasabonika	2,597,000	2023
Total Investment Cost	**5,935,000**	

Request:

a) Can WPLP confirm that funding for this metering is not included in its proposed construction budget?

Response:

The costs of these metering installations are included in WPLP's project cost estimate, and to the extent that these cost are incurred and recovered directly by HORCI, WPLP's costs would be correspondingly lower.

HORCI - 9

Reference: Exhibit C, Tab 6, Schedule 1 (pages 2 & 3) - Community Readiness. WPLP notes that the communities served by IPAs are currently in the process of transition from the IPAs to being served by Hydro One Remotes and that this transition is beyond the scope of WPLP's role as the licenced transmitter. Further, WPLP notes that infrastructure required as part of that process would be developed, owned and operated by Hydro One Remotes rather than the applicant.

Preamble:

a) As a point of clarification, Hydro One Remotes is not investing in the IPA communities or developing infrastructure prior to assuming responsibility for service. Hydro One Remotes and the ESA are supporting the communities, their Tribal Councils, WPLP, INAC and OSLP in this work by providing technical expertise and asset inspections. Hydro One Remotes and the ESA were contracted by each local community through INAC and OSLP to carry out distribution assessments and to identify necessary upgrades required before grid connection. It is Hydro One Remotes' understanding that, INAC is investing (as contributed capital) in any required distribution assessments and system upgrades in the IPA communities and that OSLP and the communities/ IPAs are responsible for completing the distribution upgrades to ESA and Hydro One Remotes' standards. The ESA and Hydro One Remotes will also assess the assets once the upgrades are complete. As part of these investments, INAC is also funding the construction of Hydro One Remote Communities work facilities Once Remotes takes over service to the IPA communities Remotes expects to manage the assets and invest in the same way as it manages assets in its existing communities.

b) Hydro One Remotes generally agrees with the list of community readiness distribution activities provided and also notes for purposes of clarification that the IPA communities must also provide customer information to Hydro One Remotes before Hydro One Remotes can take over service to the community. The customer information required is: the customer name linked to the premise/existing meter, a signed request for service; a signed form for qualification for the HST/First Nation Energy rate including the customer's band status number. Where no band status number exists, information to specifically identify the customer is required. Once this information and the asset improvements are completed and prior to the agreed takeover date, Hydro One Remotes will send its staff to the community to map the existing transformers and poles, change the meters and enter this information into Hydro One Remotes billing system.

Request:

a) Please confirm, as the Project Manager of the distribution line readiness project in Pikangikum, if that project remains on schedule? Additionally please also confirm the scheduled readiness date. Please explain the role, if any, of OSLP in the WPLP project.

b) Given the clarifications provided in the preamble 1) above, does WPLP accept this clarification?

c) Given the clarifications provided in the preamble 2) above, does WPLP also accept this clarification?

d) Does WPLP accept that Hydro One Remotes does not currently serve any of the IPA communities and that there is a potential for delays in the connection of the communities if, for example, the required asset upgrades and customer information activities, ISC and Band Council approval to issue a Section 28(2) land access agreement are not completed on WPLP's schedule?

e) Is WPLP aware that various government approvals are required for Remotes to take over service to the IPA communities, including a provincial regulation to name each community in Remotes' service territory as well as a subsequent licence amendment approval from the OEB?

Response:

a) The Pikangikum project is running slightly behind schedule. The original schedule had Hydro One Remotes taking over service of the Pikangikum IPA on November 15, 2018. The new schedule has Hydro One Remotes taking over service of the Pikangikum IPA on December 14, 2018.

OSLP's primary role in the Pikangikum project is in assisting WPLP with execution of the Pikangikum project by:

- facilitating and assisting with Indigenous engagement, participation, and communications with the Pikangikum First Nation
- preparing the preliminary budgets and the funding application with Indigenous Services Canada
- assisting in the selection of the owner engineer
- assisting in the preparation of the request for proposal to select contactor
- providing input regarding the selection of the owner's engineer and contractors
- monitoring work execution, budgets and preparing budget forecasts
- working with Hydro One Remotes to prepare and execute the transfer agreement

b) WPLP accepts HORCI's clarifications provided in the preamble a)

c) WPLP accepts the description of what appears to be HORCI's process for transferring customers from an IPA to HORCI as provided in the preamble b)

d) WPLP understands that HORCI does not currently serve any of the IPA communities and that there is a potential for delays in the connection of the communities if certain activities are not completed on WPLP's schedule. The process for identifying and completing these activities is described in response to Board Staff IR 13(a).

e) WPLP is aware that various government approvals are required for HORCI to take over service to the IPA communities, including a provincial regulation to name each community in Remotes' service territory as well as a subsequent licence amendment approval from the OEB. See also WPLP's responses to Board Staff IR 18 and 44(b).

HORCI - 10

Reference: Exhibit C, Tab 1, Schedule 1, Page 6 and, Exhibit C, Tab 6, Schedule 1 (pages 2 & 3) - Community Readiness. The success of the transfer of IPA communities to Hydro One Remotes project hinges on distribution and community readiness of each IPA, including the repair of distribution systems and the construction of operating infrastructure such as a house, yard, garage, etc.

Preamble: Hydro One Remotes notes that the Pikangikum transfer for a connection date of "late 2018" may be at risk.

Request:

a) WPLP has stated that "In respect of the seven communities listed above that are served by IPAs, these communities are currently in the process of transitioning from the IPAs to being served by Hydro One Remotes. This transition is beyond the scope of WPLP's role as the licenced transmitter." (Reference, Exhibit C, Tab 6, Schedule 1 pages 2 & 3). Would you agree that community readiness is an important element to WPLP's success of the overall project?

b) If the response to a) above is yes, what specific contingencies have you implemented to address the potential delays due to insufficient community readiness?

Response:

a) WPLP agrees that IPA community readiness is an important element to WPLP's success of the overall project.

b) The Memorandum of Understanding between WPLP, Ontario and Canada clearly lays out Canada and Ontario's commitment to provide funding and support for the existing IPA communities until such time the IPA communities have been connected to the transmission system. In the case of a delay in transitioning from the IPAs to being served by Hydro One Remotes, Canada and Ontario have committed to ensuring that the IPA communities will receive the same standard of service as they do today.

   In addition, WPLP has required the successful EPC contractor(s) to finalize detailed construction schedules in advance of the start of construction of the Remote Connection Lines, which is currently scheduled for Q4 2019. These schedules would indicate the expected completion date for each IPA community. As indicated in Exhibit C-7-1, Page 4, the forecasted milestone dates for connection of the remote communities are between Q1 2021 and Q4 2023.

It is WPLP's understanding that planning for any required upgrades to the IPA distribution systems is currently being undertaken by the relevant communities, their IPAs and INAC (Indigenous Services Canada) with support from HORCI, the Electrical Safety Authority and OSLP.

The commitment by Canada and Ontario to maintain the quality of existing services for the IPA communities until such times they are each connected to WPLP's transmission system, combined with the upfront planning efforts described above, will address the potential delays in connecting the remote communities due to insufficient community readiness.

HORCI - 11

Reference: Exhibit C, Tab 6, Schedule 1 (page 5). WPLP is seeking an exemption from the requirements for CIAs in respect of Remote Communities. WPLP states that, "further consideration would need to be given to how section 6.2 should apply in respect of additional connecting customers."

Request:

a) Please clarify this statement. For example, under the proposed exemption, would a CIA be required if an industrial customer sought a connection to the remote community transmission lines.

Response:

The requested exemption from Section 6.4 of the TSC would only apply with respect to the connection of the 16 Remote Communities, since the assessment of any impacts on the existing transmission system resulting from the connection of these communities has already been addressed through WPLP's SIA/CIA process with the IESO and Hydro One Networks. For clarity, any other large customer proposing to connect directly to WPLP's transmission system, or proposing to connect to HORCI's system in any of the 16 Remote Communities, would be subject to the applicable CIA and SIA provisions of the TSC and the IESO's Market Rules.

The reference to Section 6.2 of the TSC above is related to WPLP's position that an alternative to the traditional capacity allocation rules of the TSC may be appropriate in consideration of the unique circumstances surrounding WPLP's project (e.g. the construction of an entire transmission system in a short period of time that is designed to supply the long-term capacity requirements of 16 communities, with a relatively high rate of load growth forecasted over the life of the assets). The requested interim exemption would allow WPLP sufficient time to consult with multiple parties (which could include the Remote Communities, HORCI and IESO, among others) to consider various perspectives on how capacity allocation (i.e. assigning available capacity to the communities vs. making this capacity available to other customers) might be considered in developing WPLP's customer connection procedures which, as described in Exh J-1-1 at p. 15, WPLP intends to seek approval of in a future proceeding.

HORCI - 12

Reference: Exhibit E, Tab 1, Schedule 1 (page 1). WPLP describes its plans to monitor the configuration and status of WPLP's transmission system using information collected by SCADA devices, relays and other sensors. Transmitters often use dual communications to Distribution and Transmission Stations to ensure reliable communications with the stations.

Request:

a) Does WPLP plan dual independent communications to the Distribution Stations using secondary communications through Bell fibre services in each community?

b) Does WPLP intend to have the secondary Bell fibre connection through the poles on the community distribution system?

c) Has WPLP investigated the cost to provide this secondary communications from Bell fiber to the Distribution Stations?

Response:

a) At this point in its design process, WPLP is still considering options for redundant communications. Use of existing Bell Canada fibre would be among the considerations.

b) WPLP believes it is in the best interest of the project to investigate the possibility of providing Bell Canada with a secondary fibre connection to remote communities that they serve. WPLP has not yet completed design of secondary communications, therefore, WPLP is not in a position to provide specific details at this time.

c) WPLP has not yet investigated the cost to provide a secondary communication from Bell fibre to the Distribution Stations.

HORCI - 13

Reference: Exhibit E, Tab 1, Schedule 1 (page 4-5). Access to facilities; WPLP acknowledges the challenges related to access in this region and is proposing developing contracts with helicopter service providers to patrol the remote community lines. WPLP has also indicated (Exhibit F, Tab 1) that it plans to construct helicopter pads to enable construction of assets.

Request:

a) Please confirm that WPLP (directly or through contractors) intend to patrol the lines by helicopter once they are in service.

b) Does the construction plan include building helicopter landing pads?

c) Does WPLP believe that helicopter re-fueling stations/kiosks will be required due to the long length of these lines? If so, where would WPLP expect these refueling stations to be sited?

d) If re-fueling stations are required, has WPLP investigated the environmental risks and the mitigations required?

Response:

a) WPLP is in the process of determining the method(s) by which it will perform condition patrols of its transmission lines. While the use of helicopter (directly or through contractors) is a potential option, WPLP has not made a final decision regarding the use of helicopter services for condition patrols once the transmission lines are in service.

b) The construction plan contemplates the building of helicopter landing pads along the right of way as required for construction purposes. The use and location of the helicopter landing pads will form part of the contractor(s) construction access plan. The contractor(s) construction access plan will be developed prior to and updated during construction. WPLP intends to seek opportunities to incorporate elements from its contractor(s) construction access plan into the infrastructure it relies upon for ongoing access to the project facilities.

c) WPLP will be in a better position to determine if helicopter re-fueling stations/kiosks will be required due to the long length of these lines once a decision has been made regarding use of helicopters.

d) WPLP has not investigated the environmental risks or mitigation required at this time as the use of helicopters has not been finalized.

HORCI - 14

Reference: Exhibit F, Tab 1, Schedule 1 (page 10). WPLP says that the 56 laydown areas required during the construction period "will be required by WPLP on a temporary basis only."

Request:

a) How does WPLP anticipate making future repairs along these lines once they are in service? Will more permanent or additional temporary laydown areas be required in future?

b) Does WPLP anticipate the need to construct longer-term accommodations in any of the communities to conduct site maintenance or capital repairs on the Distribution Station ("DS") or Transmission Station ("TS") assets? If not, how does WPLP plan to manage accommodation/transportation for staff performing this work?

c) Does WPLP plan to purchase fleet to access its DS and TS assets located near the communities?

d) Does WPLP foresee a need to construct equipment storage sheds or garages near any of its TS or DS assets? If so, has funding to construct these storage facilities been included in the application?

Response:

The questions refer to DS and TS assets. To clarify, WPLP has answered HORCI IR 14 under the assumption that the reference to Distribution Station ("DS") assets refers only to the Pikangikum distribution station currently being constructed under WPLP's distribution licence (ED-2017-0236). As described in EB-2018-0190 Exhibit C, Tab 3, Schedule 1 the distribution station being constructed as part of the Pikangikum System will be converted to a transmission facility. As such WPLP has only made reference to Transmission Stations ("TS") assets in the following response.

a) WPLP will develop its preventative maintenance, capital program and emergency response plans prior to the assets going in-service. Those plans will set out WPLP's approach to making future repairs, taking into account access considerations, along these lines once they are in service. WPLP expects there will be a need for laydown areas to support future maintenance activities**.**

b) WPLP expects that once the assets go in-service, there will be a requirement to construct longer-term accommodations throughout the project area to support site maintenance and capital repairs on Transmission Station ("TS") assets.

c) Yes.

d) Yes, WPLP foresees a need to construct equipment storage sheds or garages near its planned station assets. WPLP will work with its contractor(s) to leverage any infrastructure developed as part of the construction of the project. No particular funding is sought in the application as WPLP is not requesting approval of rates at this time. The cost for any additional storage facilities not required by the contactor for construction purposes is not included in the project cost estimates included in the application.

HORCI - 15

Reference: Exhibit 1, Tab 1, Schedule 1, (page 13) describes access roads required to construct the project.

Preamble: Hydro One Remotes requires communities to have year round access either by air or road to each community to safely transport people and equipment to the communities in order to serve them. Wawakapewin currently has neither an all-season road, or an airport. In discussions with WPLP, Remotes expressed concerns about locating the TS and the distribution metering that Remotes will be required to maintain in Wawakapewin. WPLP suggested to Remotes that a service road between Wawakapewin and Kasabonika Lake is a reasonable alternative to a permanent road or airport.

Request:

a) Please describe WPLP's planned access to the Wawakepwin TS.

b) Has WPLP included funding for an access road to Wawakapewin in its application?

c) Does WPLP still consider a service road from Kasabonika Lake as a viable option for Remotes to service this community?

d) If so, has funding for road access been included in this application?

e) Can WPLP provide an update on discussions with Wawakapewin on establishing a more permanent link between the two communities?

f) If no road is currently planned is WPLP aware of the timing and location of roads or airports that any other entity (for example MTO/ISC) is constructing to the community?

g) Please confirm this proposed access will likely increase Remotes' OM&A costs post-implementation?

Response:

a) WPLP has not finalized the access plan for Wawakapewin TS. Access to Wawakapewin TS for operating purposes is not required for a number of years. As such WPLP intends to work with its contractor(s) to leverage the infrastructure developed as part of the construction of the project.

b) No particular funding is sought in the application as WPLP is not requesting approval of rates at this time. WPLP has not included the costs of an access road to Wawakapewin TS in the cost estimates that are provided in its application other than the costs associated with construction access.

c) Please refer to the response to HORCI IR 15 (a)

d) No particular funding is sought in the application as WPLP is not requesting approval of rates at this time. The costs of providing for road access from Kasabonika Lake to the Wawakapewin TS have not been included in the cost estimates provided in the Application.

e) WPLP has no additional information to provide on discussions with Wawakapewin on establishing a more permanent link between the two communities.

f) WPLP is not aware of the timing or location of roads or airports that any other entity may be planning to construct in relation to the community.

g) WPLP will be responsible for work on the Wawakapewin TS. As such, access to Wawakapewin TS should not have an impact on HORCI's OM&A costs post-implementation. Since the requirements for HORCI to take over local distribution in Wawakapewin will be determined in the Asset Transfer Agreement between Wawakapewin, HORCI and Indigenous Services Canada, WPLP is not in a position to comment on HORCI's OM&A costs post-implementation related to local distribution service for this community.

Issue: Ratepayer Impact

HORCI - 16

Reference: Exhibit J, Tab1, Schedule1, (page 2) states, "Under the alternative rate framework, the implications for ratepayers are the same as under the existing TSC and uniform transmission rates

Request:

a) Please clarify WPLP's understanding of how the implications for rate payers are the same under the alternative framework.

Response:

Under the TSC approach, the revenue requirement associated with the Remote Connection Lines would be paid by way of revenue earned through UTR and an aid to construct that would reduce WPLP's initial rate base. The source of the UTR revenue will be the load of the remote communities. Given that the revenue earned by WPLP through the UTR will be small relative to the actual capital cost of the line, the contribution in aid to construct will reflect almost all of the capital cost of the Remote Connection Lines. The contribution in aid to construct would under this scenario be paid by HORCI, thereby forming part of its rate base and its revenue requirement, which is recoverable from its distribution network customers and RRRP.

Under the alternative approach proposed by WPLP, the amount associated with the contribution in aid to construct that would be required from HORCI under the current TSC framework would instead remain in WPLP's rate base and the resulting revenue requirement would be the basis of a rate that would be charged to HORCI. The payment of that rate would form part of the revenue requirement of HORCI and be recoverable from its distribution network and RRRP as above.

The rate implications for Ontario ratepayers are the same since in both scenarios there will be the recovery of costs through RRRP funded by ratepayers. See also WPLP's response to Board Staff IR 58**.**

HORCI - 17

Reference: Exhibit J, Tab 1, Schedule 1 (pg. 10) includes the following statement:

> "The Remote Connection Lines' capital cost would be recorded and accounted for separately from the Line to Pickle Lake. Rate base additions for the Transmission Project would be segregated into two pools: (i) the amount for the Remote Connection Lines, and (ii) all other in-service capital costs. The revenue requirement impact would be calculated for each pool per the current regulatory revenue requirement methodology for transmitters."

Request:

a) Please confirm if the pool that includes "all other in-service costs" would include all capital costs associated with the Line to Pickle Lake? If not confirmed, please explain.

b) Please confirm the Pikangikum line will be recorded in rate base, and if so will it be included in one of the two pools?

c) Please confirm if the calculation of the revenue requirement associated with each pool (i.e. the Remote Connection Lines and "all other in-service capital costs" pools) would take into account any Capital Contribution received from the government of Canada for funding WPLP? If not confirmed, please explain.

Response:

a) WPLP confirms the pool that includes "all other in-service costs" would include all capital costs associated with the Line to Pickle Lake.

b) WPLP confirms that the Pikangikum Line will be recorded in rate base, and included in the Remote Connection Lines. However, as described in response to Board Staff IR 7, WPLP has received a contribution-in-aid of construction for the Pikangikum Line from INAC (Indigenous Services Canada). That contribution will be accounted for as prescribed in the OEB's Accounting Procedure Handbook, Article 40 "Accounting for Specific Items Contributions in Aid of Construction". Consequently, the amount that will be included in rate base for the Pikangikum Line will not include the initial capital costs of constructing that line, which costs will be covered by the capital contribution.

c) As explained in response to Board Staff IR 42, no capital contribution would be made in respect of the Line to Pickle Lake. However, WPLP confirms that the calculation of revenue requirement in respect of the Remote Connection Lines would take into account any capital contribution received from the Government of Canada.

<u>HORCI - 18</u>

Reference: Exhibit J, Tab 1, Schedule 1 (page 10) includes the following statement:

"To permit recovery of WPLP's OM&A expense, the expense will be allocated between the Remote Connection Lines and the Line to Pickle Lake on the basis of direct cost and indirect costs allocated based on the proportionate asset value in each rate base pool relative to total rate base."

Request:

a) Please clarify if its WPLP's intent that only <u>indirect</u> OM&A costs (e.g. administrative OM&A) are proposed to be allocated based on the proportionate asset value in each rate base pool, and that direct costs associated with maintaining assets in each pool would be directly assigned to that pool.

Response:

WPLP will allocate all OM&A expenses between the Remote Connection Lines and the Line to Pickle Lake. Direct costs will be allocated to the asset they relate to. As an example, Remote Connection Line maintenance would be allocated to the Remote Connection Line for recovery. An indirect cost such as general management would be allocated based on the proportionate asset value in each rate base pool relative to total rate base to allow for recovery.

HORCI - 19

Reference: Exhibit J, Tab 1, Schedule 1 (pg. 10) includes the following statement:

"The resulting revenue requirement impact arising from the Remote Connection Lines capital and OM&A expense would be charged to Hydro One Remotes as a direct expense through a rate applicable to service provided from the Remote Connection Lines."

Request:

a) Does WPLP anticipate that other customers (e.g. mining customers) may connect to the proposed Remote Connection Lines?

b) Would all existing Transmission System Code requirements apply to any customers looking to connect to the Remote Connection Lines?

c) What rate would be applicable to any new customers making use of the service provided from the Remote Connection Lines?

d) Would revenues collected from new customers using the Remote Connection Lines be used to offset the charges paid by Hydro One Remotes?

Response:

a) Yes.

b) As explained in Exh C-6-1, pp. 3-7, as well as in Exh J-1-1, p. 9 and Appendix 'A', WPLP is requesting various exemptions from the Transmission System Code ("TSC"), which are generally temporary in nature. WPLP may however seek a longer term exemption from Section 6.2 of the TSC (assignment of available capacity on connection facilities), as further discussed in Exh C-6-1, p. 5, and in response to HORCI IR 11. WPLP confirms that, subject to approval of these qualifications, its intention is that all TSC requirements would apply to any customer looking to connect to the Remote Connection Lines.

c) WPLP expects that the UTR rates as approved by the OEB would apply to any new customers connecting to the Remote Connection Lines, and that the capital contribution requirements contained in Section 6.3 of the TSC would apply.

d) For the purpose of illustrating the allocation of revenues from new customer connections, WPLP has provided two scenarios in the tables below.

   In Scenario 1, the incremental revenue streams (Network UTR and Line + Transformation UTR) resulting from the new load exceed the incremental revenue requirements associated with investments required to connect the new customer to the transmission system, such that no capital contribution is required from the customer. In this case, the increase in the future revenue stream from the connecting customer is in excess of the increase in WPLP's incremental revenue requirements and would offset both the rate to be paid by HORCI and the Network Pool (see lines 'M' and 'S' in the first table below).

In Scenario 2, the incremental revenue streams are less than the incremental revenue requirements associated with investments required to connect the new customer. The TSC would therefore require that the customer make capital contributions in an amount that would effectively reduce the incremental rate base to the point where WPLP incremental revenue requirements would be approximately equal to the amount of incremental revenue resulting from the new load. In this scenario, there are no offsets to the rate paid by HORCI, or to the Network Pool, but all existing customers are kept neutral with respect to the new connection, which is consistent with the intent of the capital contribution requirements of the TSC.

In addition to the capital contributions discussed above, WPLP expects that any TSC provisions relating to the refund of an initial capital contribution (i.e. Section 6.3.17 of the current TSC) would apply to any new customers, such that any capital contribution initially provided to WPLP from federal funding would be partially refunded by the new customer (in proportion to relative capacity and the specific portion of the Remote Connection Line assets providing service to the new customer). WPLP expects that it would collect this contribution from the new customer, and remit the amount to the Trust, to be used for continued offsets to future RRRP rates.

Assumptions for Scenario 1 (No CIAC)		
A	UTR - Line + Transformation ($/kW-month)	3.29
B	UTR - Network ($/kW-month)	3.73
C	New Customer Demand (kW) - Fully in-service for all of 2030	30,000
D = A * C * 12	Annual Incremental UTR (Line + Transformation) Revenue	1,184,400
E = B * C * 12	Annual Incremental UTR (Network) Revenue	1,342,800
F	Incremental RCL Rate Base Required to Connect New Customer	10,000,000
G	Incremental LTPL Rate Base Required to Connect New Customer	5,000,000
Remote Connection Lines (RCL) Revenue/Rate Impact		
H	WPLP 2030 RCL Revenue Requirement - Without New Customer[6]	101,269,209
I = F * 10%[7]	WPLP 2030 Incremental RCL Revenue Requirement	1,000,000
J = H + I	WPLP 2030 RCL Revenue Requirement - With New Customer	102,269,209

[6] From table in Board Staff 60(a)

[7] For the illustrative purpose of these examples, WPLP has made a simplifying assumption that the combination of WACC, depreciation, incremental OM&A and any tax impacts results in an incremental annual revenue requirement equal to approximately 10% of the rate base additions

K = D	WPLP 2030 RCL Revenue Requirement Recovery from Line + Transformation Pools	1,184,400
L = J - K	WPLP 2030 RCL Revenue Requirement Recovery from HORCI	101,084,809
M = L - H	Change in 2030 WPLP RCL Rate Applicable to HORCI	(184,400)
Line to Pickle Lake (LTPL) Revenue/Rate Impact		
N	WPLP 2030 LTPL Revenue Requirement - Without New Customer[8]	31,056,562
O = G * 10%[7]	WPLP 2030 Incremental LTPL Revenue Requirement	500,000
P = N + O	WPLP 2030 LTPL Revenue Requirement - With New Customer	31,556,562
Q = P - N	Change in 20230 WPLP Revenue Requirement to Network Pool	500,000
R = E	2030 Incremental UTR (Network) Revenue	1,342,800
S = Q - R	Net cost (benefit) to Network Pool	(842,800)

Assumptions for Scenario 2 (CIAC)		
A	UTR - Line + Transformation ($/kW-month)	3.29
B	UTR - Network ($/kW-month)	3.73
C	New Customer Demand (kW) - Fully in-service for all of 2030	30,000
D = A * C * 12	Annual Incremental UTR (Line + Transformation) Revenue	1,184,400
E = B * C * 12	Annual Incremental UTR (Network) Revenue	1,342,800
F	Incremental RCL Rate Base Required to Connect New Customer	15,000,000
G	Incremental LTPL Rate Base Required to Connect New Customer	15,000,000
Remote Connection Lines (RCL) Revenue/Rate Impact		
H	WPLP 2030 RCL Revenue Requirement - Without New Customer (from Staff 60(a))	101,269,209
I = D[9]	WPLP 2030 Incremental RCL Revenue Requirement due to New Customer	1,184,400
J = H + I	WPLP 2030 RCL Revenue Requirement - With New Customer	102,453,609
K = D	WPLP 2030 RCL Revenue Requirement Recovery from Line + Transformation Pools	1,184,400
L = J - K	WPLP 2030 RCL Revenue Requirement Recovery from HORCI	101,269,209
M = L - H	Change in 2030 WPLP RCL Rate Applicable to HORCI	0
Line to Pickle Lake (LTPL) Revenue/Rate Impact		
N	WPLP 2030 LTPL Revenue Requirement - Without New Customer (from Staff 59(a))	31,056,562

[8] From table in Board Staff 59(a)

[9] Assumption that the CIAC required by TSC calculation will result in a reduction to WPLP's RCL rate base such that the increase in WPLP's RCL revenue requirement is limited to the amount of incremental revenue from the Line + Transformation UTRs

O = E[10]	WPLP 2030 Incremental LTPL Revenue Requirement due to New Customer	1,342,800
P = N + O	WPLP 2030 LTPL Revenue Requirement - With New Customer	32,399,362
Q = P - N	Change in 20230 WPLP Revenue Requirement to Network Pool	1,342,800
R = E	2030 Incremental UTR (Network) Revenue	1,342,800
S = Q - R	Net cost (benefit) to Network Pool	0

[10] Assumption that the CIAC required by TSC calculation will result in a reduction to WPLP's LTPL rate base such that the increase in WPLP's LTPL revenue requirement is limited to the amount of incremental revenue from the Network UTR

HORCI - 20

Reference: Exhibit J, Tab 1, Schedule 2, (pages 1-2) includes the statement, "Following the substantial completion and completion dates, Canada will fund the Transmission Project in part as a capital contribution paid to WPLP and with the remainder placed in an independent trust (the "Trust") which will provide a ratepayer subsidy payment over time to offset transmission rates charged by WPLP."

Slide 36 in the presentation made by Wataynikanenyap Power LP, to the OEB, on November 2, 2018 indicates that only the amount of "Rate base before capital contribution" that is in excess of the implied rate base of $1,550 million will be paid as a capital contribution to WPLP, with the balance amount allocated to the Trust for use in offsetting RRRP costs.

Request:

a) What determines how much of the $1.56B in Canada funding will be paid as a capital contribution to WPLP versus being put into the Trust?

b) Has WPLP considered splitting the government funding between the Remote Connection Lines (whose costs to be covered by RRRP) and "all other in-service capital costs" pools (whose costs will be covered by UTRs) based on the proportionate asset value in each pool?

c) Given that the Trust will be used to offset the increase in RRRP costs associated with the increase to Hydro One Remotes' revenue requirement as a result of charges for use of the Remote Connection Lines, why is it appropriate that the government funding allocated to the Trust be more than the rate base associated with the Remote Connection Lines?

Response:

a) Please refer to the responses to Board Staff IR 46 (a) and Board Staff IR 50 (a).

b) Please refer to the response to Board Staff IR 42 (a).

c) Please refer to the response to Board Staff IR 41 (d).

HORCI - 21

Reference: Exhibit J, Tab 1, Schedule 2, (page 2) includes the following statement:

"The purpose of the Trust is to offset the impact on RRRP of any rates charged by WPLP in respect of transmission services."

Request:

a) Is it the intent that payments from the Trust would fully offset the impacts on RRRP due to the increase in Hydro One Remotes' revenue requirement as a result of paying for the use of the Remote Connection Lines?

b) How does WPLP assume that the payments from the trust to offset the impact on RRRP of any rates charged by WPLP in respect of transmission services will be administered? Would the Trust make payments to the IESO or some other entity?

Response:

a) The purpose of the Trust would be to offset the impact on RRRP arising from the increase in HORCI's revenue requirement due to WPLP charging HORCI a rate based on WPLP's revenue requirement for providing services from the Remote Connection Lines until such time as the funds in the Trust are fully utilized. However, the amounts of payments from the Trust would be at the discretion of the Trustee and Ontario.

b) Please see response to Board Staff IR 48 (c).

HORCI - 22

Reference: Exhibit J, Tab 3, Schedule 1

Request:

a) Please confirm that the impacts shown in Tables 2 to 4 are based on receiving no funding contributions from any level of government?

b) What would the impacts in Tables 2 to 4 be assuming government funding of the Transmission Project per the Funding MOU WPLP has entered into with Canada?

c) The residential bill impact shown in Table 2 is based on the average annual revenue requirement associated with the Line to Pickle Lake. Can you please reproduce Table 2 to show what the maximum impact on a typical residential bill will be (i.e. when the project is first put into service and costs are collected through rates)?

d) The impact on the RRRP rate is shown based on the average annual revenue requirement associated with the Remote Connection Lines. Can you please reproduce Table 3 to show the maximum impact on the RRRP rate will be (i.e. when the full cost of all Remote Connection Lines are charged to Hydro One Remotes)?

e) Does WPLP agree that the RRRP rate impact shown in Table 3 will be higher allowing for typical inflationary increase in the cost-to-serve for Algoma Power Inc. and Hydro One Remotes over the 2024 to 2033 period?

f) Please provide an update to Table 4 and Table 5 taking into account the maximum impacts as calculated in c) and d) above.

Response:

a) Confirmed.

b) Please see response to Board Staff IR 60 (b).

c) The table has been reproduced below to show the maximum annual Network UTR impact alongside the 10-year average impact from Exhibit J-3-1. The maximum impact is based on the first full year in service (2021), in order to reflect the maximum amount of revenue requirement associated with the Line to Pickle Lake. Additionally, the WPLP Network charge determinants in the UTR calculation consider only the 2021 billing determinants from those communities listed as in service during or before 2021 in Table 2 of the preamble to HORCI 8, and further divided this total by 2 to reflect staggered in service dates during that year.

Residential Bill Impact (Network Service Rate)			
		J-3-1	HORCI 22
A	Typical Monthly Bill	$116.55	$116.55
B	Portion of bill related to Network Service rate	$5.41	$5.41
C	Increase in Network Service rate (%)	3.43%	3.76%
D = B x C	Bill increase resulting from increase in Network Service rate	$0.19	$0.20
E = D / A	Bill impact (%)	0.16%	0.17%

d) The table has been reproduced below to show the maximum annual RRRP impact alongside the 10-year average impact from Exhibit J-3-1. The maximum impact is based on the first full year in service (2024), in order to reflect the maximum amount of revenue requirement associated with the Remote Connection Lines. The energy forecast for Ontario was also updated to reflect 2024 only.

RRRP Rate Impact (Rounded to nearest thousand)			
	2018[11]	Remote Connection Line Impact	
		J-3-1	HORCI 22
First Nations (O.Reg 442/01, Schedule 1)	$ 1,600,000	$ 1,600,000	$ 1,600,000
Algoma Power Inc.	$ 13,155,000[12]	$ 13,155,000	$ 13,155,000
Hydro One Remotes	$ 35,223,000[13]	$ 35,223,000	$ 35,223,000
Hydro One Remotes – Additional	-	$ 103,695,000	$110,565,000
Total	*$49,978,000*	*$153,673,000*	*$160,544,000*
Ontario TWh	131.8[14]	152.008333[15]	147.725000[16]
RRRP Rate - $/kWh	**0.0003[17]**	**0.0010**	**0.0011**

[11] In its December 20, 2017 Decision and Order in EB-2017-0333, the Board included an amount of $12.3316 million in its total RRRP requirement for 2018, reflecting an estimate of IESO undercollection in 2017. For the consistency in cost comparison, this date-specific variance account balance is omitted from Table 3.

[12] Decision and Order, EB-2017-0025, December 20, 2017

[13] Final Rate Order, EB-2017-0051, April 12, 2018

[14] Decision and Order, EB-2017-0333, December 20, 2017

[15] Average of 2024-2033 forecast for all outlook scenarios contained in IESO Ontario Planning Outlook: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/ontario-planning-outlook/ontario-planning-outlook-september2016.pdf?la=en

[16] Average of 2024 forecast for all outlook scenarios contained in IESO Ontario Planning Outlook

[17] In its December 20, 2017 Decision and Order in EB-2017-0333, the Board maintained the RRRP rate at $0.0003/kWh. The 2018 rate presented here is consistent with the OEB-approved rate, and is not calculated based on the 2018 costs and load forecasts presented in this table.

e) The 2018 approved RRRP amounts were held constant during future periods in Table 3 (and any updates to that table provided in interrogatory responses) in order to isolate the RRRP impact of the revenue requirement associated with the Remote Connection Lines. WPLP acknowledges that these amounts will change as a result of any future Board decisions that alter the approved revenue requirement of either Algoma Power Inc. or Hydro One Remote Communities Inc.

f) The maximum impacts calculated in (c) and (d) occur in different years (2021 vs 2024). In order to calculate the maximum combined bill impact (which would occur in 2024), the Network UTR impact table was recalculated below, based on the forecasted revenue requirement and charge determinants from 2024.

Residential Bill Impact (Network Service Rate - 2024)		
A	Typical Monthly Bill	$116.55
B	Portion of bill related to Network Service rate	$5.41
C	Increase in Network Service rate (%)	3.52%
D = B x C	Bill increase resulting from increase in Network Service rate	$0.19
E = D / A	Bill impact (%)	0.16%

Updates to Tables 4 and 5 from J-3-1, based on the above 2024 Network UTR impacts, and the 2024 RRRP impacts from (d) above, are as follows.

Residential Bill Impact (RRRP Rate 2024)		
A	Typical Monthly Bill	$116.55
B	Portion of bill related to RRRP rate	$0.24
C	Increase in RRRP rate (%)	266.67%
D = B x C	Bill increase resulting from increase in RRRP rate	$0.65
E = D / A	Bill impact (%)	0.55%

Residential Bill Impact (Total Impact 2024)		
A	Typical Monthly Bill	$116.55
B	Increase due to Network Service rate impact	$0.19
C	Increase due to RRRP impact	$0.65
D = B + C	Total bill increase	$0.84
E = D / A	Bill impact (%)	0.72%

SCHEDULE HORCI 3 (d) – OSLP Presentation

OPIIKAPAWIIN SERVICES

November 2018

Backup Power Planning & Next Steps

Background

- Wataynikaneyap is required to facilitate the arrangement of backup power resources for the First Nations that will become grid-connected
- According to Ontario's Independent Electricity System Operator:

"*At a minimum, back up power will maintain supply to essential loads within critical buildings (nursing station, airport, water treatment plant, and at least one of school / band office / community centre) in each community, consistent with each community's Emergency Preparedness Plan*"

- Government commitments related to Backup Power are required as part of the overall Wataynikaneyap Project Funding Framework and are being negotiated by First Nations LP (FNLP) as part of the Parallel Negotiating Process

Background

- Wataynikaneyap engaged an engineering firm (BBA) to conduct a preliminary assessment of backup power options and associated costs
- Forecasted line reliability and outage estimates by community
  - Transmission Line outage estimates per community range from 0.75% - 1.65% of the year
  - **Note:** This does not include local distribution outages
- Community backup power requirements will need to consider what are critical loads, coverage of back up power, funding & operating responsibilities, and the community emergency response plan

BBA Backup Power Study

- In their report, BBA Engineering recommends using the existing diesel generation systems for backup power in the near/medium term since:
  - There is existing diesel generation in all communities
  - Some technologies (i.e. battery storage) are still in their early stages and unproven to be implemented
  - The timing to develop/implement some options (i.e. renewables) is too long and hindered by changes in Provincial policy
  - Some options do not provide sufficient backup coverage on their own (i.e. wind, solar, etc.)
- While diesel generation is recommended for the near/medium term, other options should continue to be considered in the future or developed in tandem with the diesel solution

BBA Study Next Steps

- The BBA Engineering Study did not address the capital and operating requirements to use the existing generators for back up power
- In particular, the condition of the non Hydro One Remotes community (IPA) generators was unknown and would require further inspection

Hydro One Remotes Study

Hydro One Remotes was engaged to complete the following for the 16 communities to be connected:

1. Research backup power requirements and develop criteria to convert the diesel generation stations for backup power
2. Develop a reliability and service standard for backup diesel generating stations (e.g. response time)
3. Site visits to the IPA First Nations to assess their DGS's and determine their suitability to convert to backup stations
4. Compare condition of all stations to backup criteria developed earlier
5. Determine Operations & Maintenance requirements
6. Estimate initial backup station conversion costs, yearly operation and maintenance costs, and future upgrade costs
7. Identify local employment opportunities as part of the operation of the generators for back up power

Backup Power Considerations

- The following needs to be considered for diesel back up power:
  - What additional capital is required to operate the generators as back up?
  - What will be the coverage provided by the diesel backup and for how long?
  - Who will own & operate the backup power assets?
  - Environmental contamination issues
  - Will the additional capital be invested in the generation facilities in the future or will they be decommissioned at end of life?
  - If the community load exceeds the generation capability, how will that be managed?
  - What is the condition of existing backup systems at critical infrastructure?
  - Would centralized backup power replace the need for additional backup at some critical infrastructure?
  - What are the impacts to the communities from outages?

Backup Power Considerations

- In addition, Ontario and Canada need to address cost responsibility for back up generation:
  - First Nations communities will not bear the costs of back up power
  - Canada has agreed to fund backup power for Canada-funded critical assets (e.g. water treatment plant, wastewater treatment plant and lift stations, school, nursing station and nurse residences, fire halls)
  - Need to determine cost responsibility if the existing generators will be used for back up power

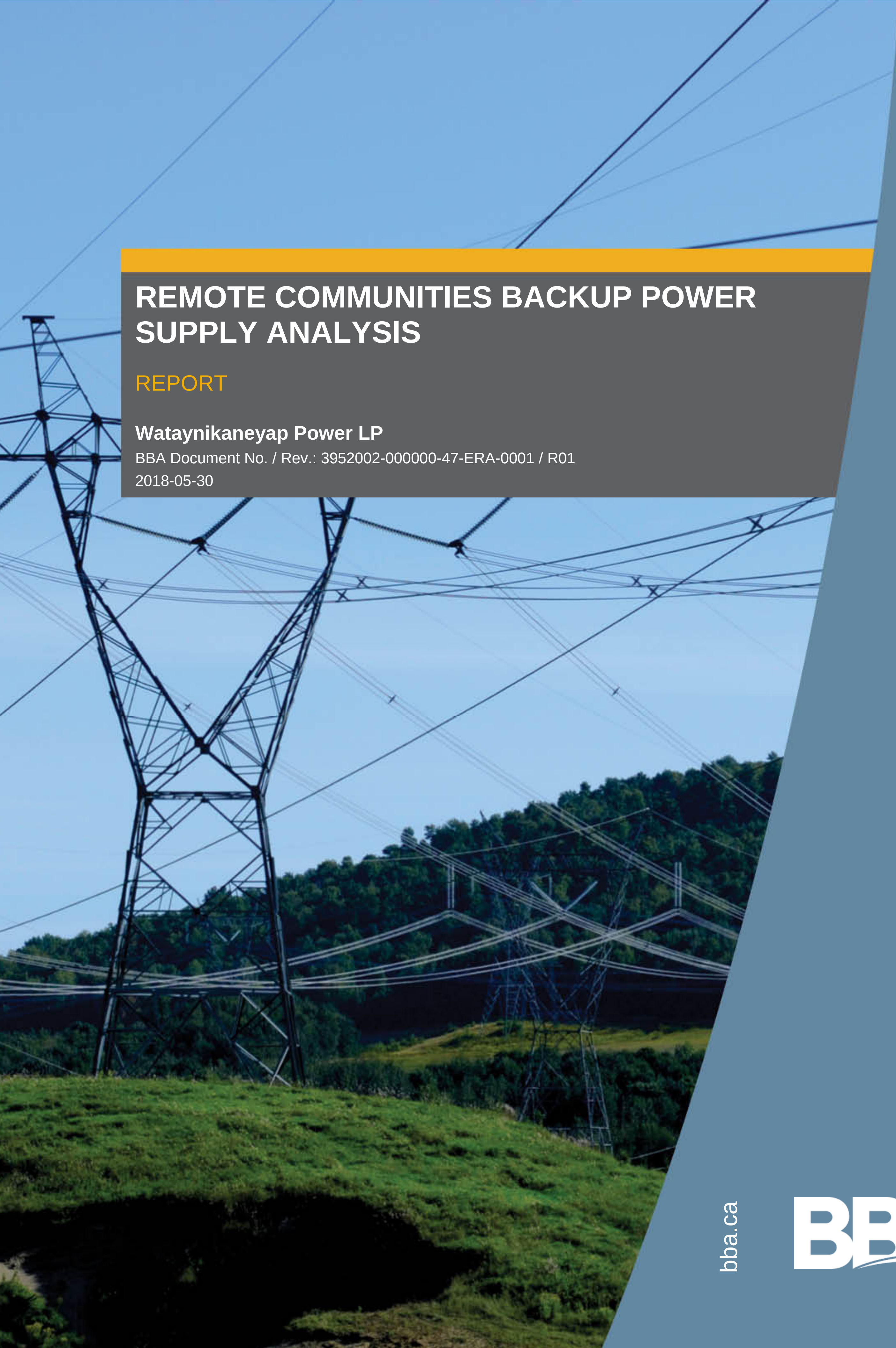
Next Steps

- Continue to seek community feedback on backup power
- Hydro One Remotes will finalize their study on the existing generators by November 14th
- Document commitments from Canada and Ontario on back up power

Feedback

- Your feedback is required…
  - What are your expectations for backup power service & reliability?
  - What is a reasonable response time for the backup power to start?
  - What are the impacts from power outages in your community?

SCHEDULE HORCI 4 (a) – BBA Report



REMOTE COMMUNITIES BACKUP POWER SUPPLY ANALYSIS

REPORT

Wataynikaneyap Power LP

BBA Document No. / Rev.: 3952002-000000-47-ERA-0001 / R01

2018-05-30

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Wataynikaneyap Power LP (WPLP)

Wataynikaneyap Transmission Project

Northwestern, Ontario

Technical Report

Remote Communities Backup Power Supply Analysis

BBA Document No. / Rev. 3952002-000000-47-ERA-0001 / R01

May 30, 2018

FINAL – Revised

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R00	Final	2018-03-21

EXECUTIVE SUMMARY

Wataynikaneyap Power LP (“WPLP” or “Wataynikaneyap Power”) has been designated by Ontario Order in Council to develop and construct the Wataynikaneyap Transmission Project: approximately 1,800 kilometres of transmission lines to connect 17 First Nations communities to the provincial electricity grid. Grid connection of remote First Nations has been identified as a priority in Ontario’s Long-Term Energy Plan, and WPLP’s scope of work as recommended by the Ontario Independent Electricity System Operator (“IESO”) includes a requirement to facilitate backup power supply for the Remote Communities to be connected by the Project. This report has been prepared to assist WPLP in fulfilling that requirement.

BBA was tasked with analysing baseline data provided by Wataynikaneyap Power relating to load demand, installed diesel generators and fuel storage capacity, and critical infrastructure in Remote Communities in order to evaluate service interruptions due to outage in the Communities once the Project is complete, and various backup supply scenarios for when outages occur.

BBA has evaluated the common causes of interruptions (e.g. unknown, scheduled outage, loss of supply, tree contacts, lightning, defective equipment, adverse weather, adverse environment, human element and foreign interference) and estimated that outage frequency would vary between 0.75% and 1.65% of the time per community. Design, construction and operations and maintenance (“O&M”) considerations also have the potential to significantly impact reliability of the network and outage frequency and duration.

Various supply technologies were studied in order to assess their potential viability under identified backup power scenarios (Appendix A). Utilization of diesel generators presents the most benefit for being initially integrated under a backup power plan for the Remote Communities, although renewable generation and other technologies should still be considered as long-term solutions and be further evaluated on a case-by-case basis.

The following five scenarios were developed to evaluate the Net Present Cost (“NPC”) of using diesel generators as backup supply in each community. Analysis was focused on the first five years of transmission operation after communities are connected to the grid; it is recommended that further studies be conducted after community connection to account for recorded outage data and further advancement of supply technologies:

1. Diesel generators must serve 100% of community load demand (full backup): provides the most coverage to the community but involves substantial investment;
2. Diesel generators must serve 50% of community load demand (i.e. partial backup which means limiting demand during an outage by shedding some type of load or applying sequential load-shedding scenarios in the event of an extended winter outage to avoid damaging community infrastructure). From a cost perspective, except for the IPA communities that would still require investment at Year 0, the generator capital cost could differ by eight to eighteen years compared with Scenario 1.

3. Existing diesel generators used only until end of life, then only provide critical infrastructure backup: allow coverage for more frequent and longer outages that communities will have to face over the first years of service of the transmission line. Afterward, only the critical infrastructure would be equipped with backup diesel generators.
4. Diesel generators only for critical infrastructure: one with the lowest investment, but does not provide any coverage during outage for the community at any time after connection.
5. Multi-community solutions, where one diesel generator may be able to supply multiple communities in lieu of retrofitting/replacing another DGS unit: allow reducing the investment when installed capacity is higher than the load demand but would leave communities in the cluster vulnerable should the distribution connection fail along with the transmission line.

It was found that estimated load growth in the Remote Communities and capital replacement costs for diesel generators were the factors that most significantly affected NPC calculations.

Backup power planning must also consider community preferences. The following recommendations have been provided to allow developing a backup power plan that meets each community's needs:

- During the Project design phase, ensure that transmission line design integrates best practices to minimise outage scenarios (as presented in Table 3);
- Develop grid outage response recommendations that can be integrated into community Emergency Preparedness Plans;
- Review available community infrastructure data to verify completeness and eliminate discrepancies, in order to refine capital investment estimates;
- Considering the high replacement cost of diesel generators (averaging $7.50 per installed Watt), develop business cases for each community to identify viable alternative technologies (i.e. renewables) including consideration of available incentive programs, transmission line performance, VAR support requirements, capacity requirements, socioeconomic benefits, etc.;
- Achieve consensus on responsibilities for investment, ownership, and operations and maintenance of backup supply options throughout the life cycle of the project;
- Regularly review NPC assumptions. The load growth factor (4%) and the replacement diesel generator capital costs significantly influence the NPC, so it is important to keep these accurate and updated;
- Evaluate the requirements for implementing automatic load shedding with load type and customer priority in each community prior to connecting to the grid. This would be highly beneficial when facing high growth rates or to easily adapt to different backup solutions to minimize the investment and to afford contingency conditions;

- This study should be revisited few years after connection date (before 2025), once historical outage duration and frequency data is available. Load growth should be reviewed based on new living habits of the communities post-connection (such as the use of electrical heating). Additional data should be gathered on the existing diesel generator's condition, and business cases developed to consider new technologies. This backup power plan study should be considered as part of planning and decision making around near term investments in remote First Nation diesel generating systems.

Ultimately, each community must establish what is critical to remain powered from a safety point of view and evaluate their acceptable level of risk to face different types of outages in order to identify their requirements, i.e. solution or set of solutions.

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1. INTRODUCTION

Under Ontario's Long-Term Energy Plan, one of the priorities identified is to connect remote First Nations to the province's electricity grid. The ongoing Wataynikaneyap Transmission Project is presently developing and constructing approximately 1,800 km of transmission lines to connect 17 remote Northern Ontario communities to the grid. Wataynikaneyap Power ("Wataynikaneyap Power") has been designated by the province as being required to develop the Wataynikaneyap Transmission Project in accordance with the recommended and supported scope developed by the Independent Electricity System Operator ("IESO"), which includes a requirement for Watay Power to facilitate backup power supply for the remote communities served by the project. The following requirement has been identified as part of the IESO supported scope with respect to the remote connection portion of the project:

> Facilitate the arrangement of backup electricity supply resources for connecting communities where: such facilities do not already exist, other arrangements have not been made or the community has not specifically requested an exemption. The backup supply resources, at a minimum, will maintain supply to essential loads within critical infrastructure (nursing station, airport, water treatment plant, and at least one of school/band office/community centre) in each community, consistent with each community's Emergency Preparedness Plan.

This report has been prepared to assist Watay Power in fulfilling the requirement to facilitate backup supply for the Remote Communities.

The Wataynikaneyap Transmission Project includes two separate, radial transmission systems connecting to the provincial transmission grid at Red Lake and Pickle Lake and serving Remote Communities north of those locations. Communities to be served by the Project are therefore delineated into either the Red Lake cluster or Pickle Lake cluster.

> BBA has been mandated by WPLP to propose and analyse different scenarios that could be considered for backup power for the communities during grid outages. BBA's report will be used as a guideline during further discussions between stakeholders and the remote communities to identify scenarios that may meet the specific needs of each community.

The study has been divided in three stages:

Stage 1: Identification of study requirements

In Section 4, the baseline data provided by the study group are analysed to provide a quick overview of the conditions for the 16 communities.

Stage 2: Identification of backup power scenarios

In Section 5, BBA and the project group have shortlisted five scenarios, using diesel generator technology, to be developed that meet the backup power requirements immediately after connection. Additional scenarios that could become interesting in the near future were listed for which business cases should be developed, based on each community's interest and need.

Stage 3: Perform scenario evaluation

In Section 6, the scenarios are described to identify the requirements in terms of critical infrastructure and community backup power infrastructure based on full or partial backup scenarios and outage coverage requirements. A Net Present Cost (NPC) analysis was developed to evaluate the 40-year cycle cost of the project (in 2021 dollars). Assumptions were made to compare the scenarios at a planning level of accuracy. Cost evaluation criteria were used to identify the benefits and risks of each scenario. It is worth mentioning that the intent is not to recommend one scenario applicable for all communities or for a specific one, but to provide the relevant information to the First Nations and other stakeholders to allow them to make the right decisions and plan the post-connection period accordingly.

In Section 7, potential ownership and operating structures for the backup power equipment are discussed.

In 2015, a previous report, *Diesel Backup Study Report for Remote Communities in Northwestern Ontario Post-Grid Connection* (the "2015 Draft Report Study"), was prepared by the IESO, Hydro One Remote Communities Inc. (H1RCI), the former Aboriginal Affairs and Northern Development Canada (AANDC) now known as INAC and a First Nation proponent for the lines to connect the remote communities, Wataynikaneyap Power ("Watay Power"). The following paragraph summarises the scope of this study.

The purpose of this study was to assist in refining the assumptions made in the Remote Community Connection Plan for diesel backup generation in remote communities that are planned for connection to the Ontario transmission system by:

- Outlining the technical options available for achieving the backup service
- Estimating the costs, benefits and risks of these technical options
- Developing the potential ownership structures and any related regulatory barriers

To achieve the above, the current baseline was documented to have an understanding of the existing diesel generating systems in the communities and the demand forecast for the communities post-connection were evaluated.

Technical options for diesel backup supply were developed using information gathered. The technical options that are considered in the study have been developed at a planning level of accuracy:

1. Retaining existing community-wide generation facilities, with no future expansion, but with replacement of existing facilities at end of life. Some buildings will continue to have backup generators.
2. Decommissioning existing community-wide generation facilities and utilizing only building backup generation for critical infrastructure.
3. Retaining existing community-wide generation facilities, with no future expansion or replacement and a diligent maintenance regime. Decommissioning existing community-wide generation facilities at end of life and utilizing only building backup generation for critical infrastructure.

The evaluation shows that option 3 provides the greatest balance of the attributes considered in this study.

2. BASIS OF STUDY

The following key assumptions underlie this backup power plan analysis:

Requirements for the emergency power systems should be defined by the Chief and Council of each community. CSA standards (C282, Z32) and National Building Code (NBC) of Canada provide general requirements that should be used as guidelines in preparing an Emergency Preparedness Plan by the community. The backup power profiles by community detail the critical infrastructure requiring emergency power or dedicated energy systems. These facilities are required by the National Building Code in any scenario, i.e. are common operating and maintenance costs in all scenarios. The initial investment required to install a backup generator at the locations where none currently exist is covered separately since funding can come from a separate entity.

The load demand for the first five years following transmission line connection 2021-2025 is based on the load demand forecast provided for this study and considers an annual growth rate of 4%. An updated report should be prepared for the following period (2025-2030) to consider the recorded outage data from the first five years of service of the transmission lines, advancement of technology, etc. Each community will also decide how they will manage heating loads (fuel type or electricity use or other considerations). This will significantly influence the community load demand forecast.

The following applies to the Capital Diesel Generator Cost. In a year where peak demand exceeds 85% of the installed capacity in a H1RCI community, a new generator is installed with capacity to meet peak demand 10 years beyond. Existing generators are assumed to remain in service for the entire study period. In an IPA community, diesel generators are replaced in Year 0 by a diesel generator with capacity equal to the peak demand forecast 10 years beyond (when applicable, except for Scenario 3).

By extending the Ontario transmission line network to connect the remote communities, the Ontario grid provides the **prime** power to the remote communities. The intent of this study is to propose different scenarios to fulfill the **backup** power needs of the remote communities; consequently, no micro-grid option has been considered.

Some potential backup power solutions could have the capability to generate additional capacity for the grid. Providing a local source of power can both address the need for power in the event of a line outage and provide a source of revenue/reduced cost for day-to-day use of energy in the community and other nearby communities. However, in Ontario the generator would need a Power Purchase Agreement (PPA), but cannot be owned by a transmission company. These initiatives would need to come from an Independent Power Producer (IPP), industrial companies or another entity allowed to connect generation to the grid (at the transmission or distribution level).

Transmission line design integrates good practice to minimise outage scenarios.

As stated in the 2015 Draft Report Study, diesel generators in H1RCI communities at the time of connection are assumed to have a remaining life of 25 years. However, it is assumed in the current analysis that this prediction can be extended to 40 years at least when used as backup power and when maintenance is performed as per schedule. Due to the generally poor condition of equipment in Independent Power Authorities (IPA) service areas, these generators are assumed to have a remaining life of 5 years. H1RCI will be the Local Electricity Distribution Company (LDC) for all those communities, but it is not clear if they will continue to own the existing Diesel Generating Stations (DGS) as part of their new roles and responsibilities.

As stated in the 2015 Draft Report Study, H1RCI's and IPA's fuel storage equipment are in good enough condition to be considered reliable backup power on day one (however, no information was available for the ones installed at Pikangikum and Keewaywin, which were also assumed to be in good condition).

The complexity of delivering fuel to the remote communities will become increasingly more complicated considering that 15 of the 16 communities are only accessible through winter roads. Recent climate change is leading to these roads being available for fewer weeks per year and this trend is continuing (e.g., a road available for 10 weeks 10 years ago may only be available for 6 weeks today and 4 in five years). This complexity is recognized by this study. With that said, delivery of diesel fuel on an annual basis is considered acceptable.

In order to properly recognize the interests of the various parties involved in the implementation of the backup power plan, a First Nations and stakeholder matrix has been developed at the early stage of this study.

Table 1: First Nations and Stakeholders matrix

First Nations and Stakeholders	Role	Interest
Remote First Nation Communities	▪ End-user of electricity. ▪ Manage the lands and resources within individual communities as well as homelands.	▪ Improve reliability of electricity supply by reducing power outage frequency and duration. ▪ Increased economic development opportunities ▪ Reduced environmental impact ▪ Invest in people (e.g., skills and employment) ▪ Improve their social and living conditions
Watay (WPLP) 51% FN, 49% Fortis	▪ Owner, developer, operator and maintainer of the transmission line. ▪ Mandated by the IESO to facilitate backup power supply for communities to be served by the Project.	▪ Provide a power backup plan report to the provincial regulatory authority. ▪ Develop a transmission line network that will limit outages (planned and unplanned).
Opiikapawiin Services LP (OSLP)	▪ Collectively represent 22 First Nations' interests including the 16 impacted by the new transmission lines.	▪ Ensure that the report will provide an accurate and efficient guideline to individual FNs. ▪ Offer support to identify proper energy solutions for Indigenous communities.
H1RCI	▪ Existing LDC for 10 of the remote FN communities. ▪ Will maintain this role after construction of the transmission line and with respect to the distribution network, and will assume the role of LDC for current IPA communities.	▪ May need to maintain the backup power system. ▪ Facilitating the removal of connection restrictions for the majority of customers; thus, allowing the communities to grow. ▪ Need to upgrade their existing distribution system to adapt to the new transmission system.
IPAs	▪ Existing LDC for 6 remote communities, own the distribution system (will not maintain their role as LDC).	▪ May need to maintain backup power system. ▪ Need to upgrade their existing distribution system to adapt to the new transmission system.
IESO	▪ Independent Electricity System Operator	▪ Ensure reliable and sustainable electricity service to the community. ▪ Ensure that arrangement of backup electricity supply resources is facilitated as per the supported scope
OEB	▪ Ontario' independent energy regulator	▪ Work to ensure a sustainable and reliable energy sector that helps consumers get value from their natural gas and electricity services – for today and tomorrow.
CIRNAC and Indigenous Health Canada (formerly INAC)	Newly created federal ministries that support the Government of Canada in renewing the nation-to-nation, Inuit-Crown, and government-to-government relationship between Canada and Indigenous peoples. ▪ Potential source of funding for some initiatives.	▪ Support the First Nations in the transition from diesel to transmission line connection.
Provincial and Federal Governments	▪ Providing acceptable living conditions to the population.	▪ Serve remote communities currently living with limited services. ▪ Provide economic development and growth opportunities.

3. STAGE 1: IDENTIFICATION OF STUDY REQUIREMENTS

3.1 Baseline data collection

As input to this study, the following documentation has been provided by the study group:

- Diesel Backup Study Report for Remote Communities in Northwestern Ontario Post-Grid Connection (the "2015 Draft Report Study");
- Backup Power Profile developed by Hoshizaki Development 2017 for each of the seventeen communities;
- UPDATED ANALYSIS - Capital Cost ($) / kW Capacity, AANDC Ontario Sample DGS Projects – Updated April 2015 (CIDM 572508);
- INANC infrastructure table.

The following information has been recorded in map form to provide a quick overview of the conditions for the 17 communities:

- Load demand for the studied period, i.e. 2021 and 2025;
- Capacity of presently installed diesel generators;
- Present LDC, i.e. H1RCI and IPA;
- Population (based on information from "Registered On Own Reserve" reference data) and number of houses;
- Need for reactive support;
- Potential future hydro capacity nearby (in capitals).

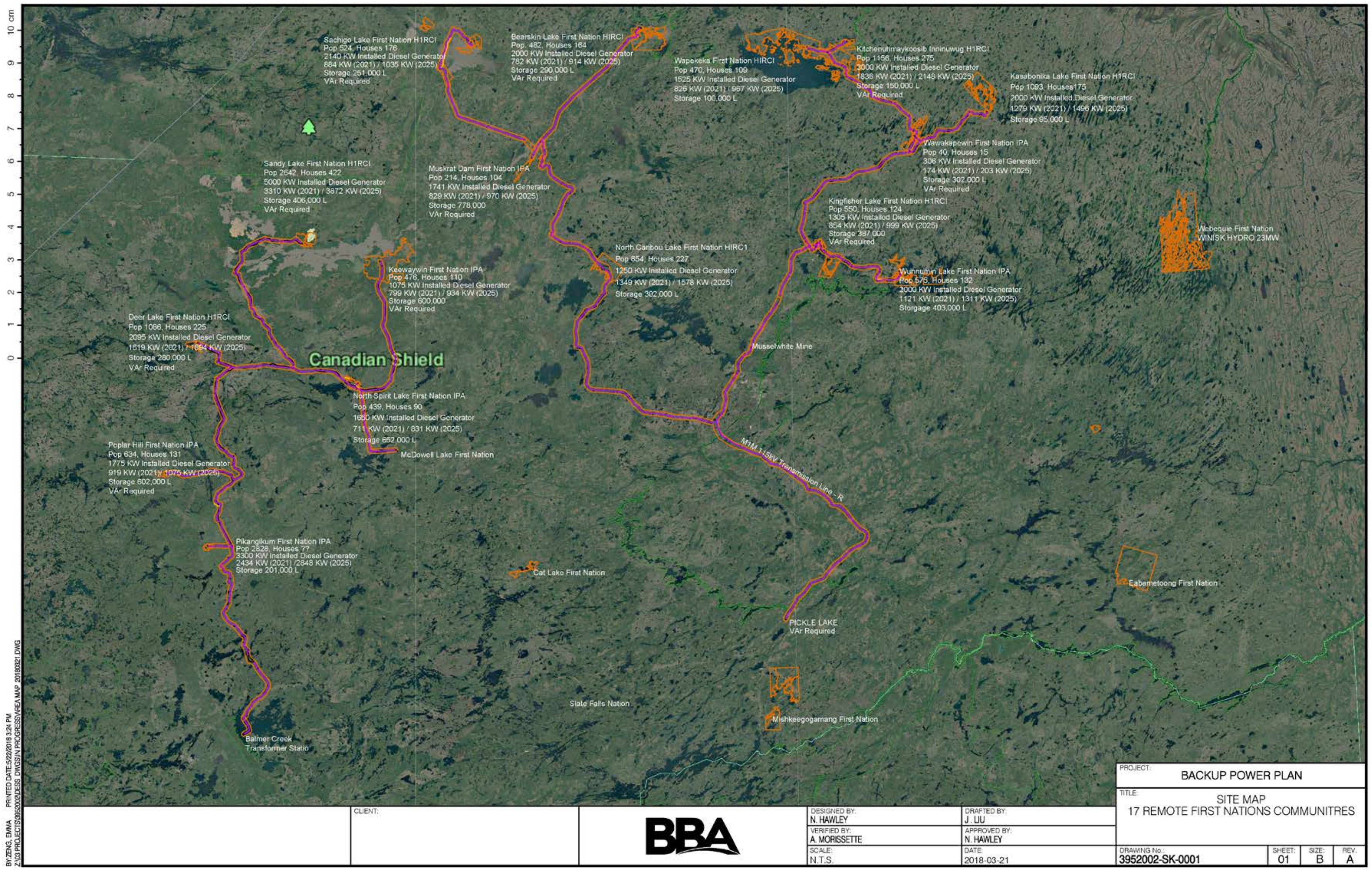

Figure 1: Overview of Community Conditions

The existing community assets and infrastructure are shown in Appendix C within summary tables following the compilation of surveys issued to all 16 communities. However, it would be important to confirm the validity of the information provided which influences the investment cost required to provide emergency power to critical infrastructure. Additional information was provided along the study from the INAC survey to provide more accurate base line data. Some discrepancies have been identified between the different sources; however, some information was still unavailable, as highlighted in Figure 2.

3.2 Forecast line reliability and community outages

To be able to define the autonomy required per community in terms of backup power, transmission outage scenarios have been established using information provided by Five Nations, Yukon Energy, the OEB's yearbook structure and experience from previous projects, such as BBA's experience in the remote communities of British Columbia.

From analysis performed in the past, transmission system outages have been evaluated a few times leading to different forecasts. The previous report established that remote communities could experience transmission system outages approximately 2% of the time. Furthermore, the OPA connection plan states that backup power could be required 5% of the time. The basis of the present analysis must be well understood in order to interpret the statistics:

- Average annual frequency and duration; i.e. that one event can last longer if its probability of occurrence is once every five years. Since the table shows average annual values, the 1:50 year probability of facing a one-week outage due to major damage to the transmission line with limited access, for instance, is hidden in the statistics.
- Good practices are considered in designs such as ring bus configuration, redundant substation transformers and single-pole switching, which significantly improve outage rates and recovery time, as per Table 3.
- The outage statistics used in the outage matrix (Appendix D) represent the outage probability for the first 10 years of operation. However, probability will vary over time (often known as the bathtub failure curve) e.g. the first three years will have more and longer outages as equipment wears in and design/construction issues are identified. Then a relatively stable, low outage period sets in, followed by more equipment failure after 20-30 years of operation as equipment ages and wears out.
- The backup power system will start up to cover outages lasting longer than one hour; community outages will be assessed accordingly. In addition, in order to restore the complete network following a blackout of the entire system, the community will see a second outage lasting between 30 to 90 minutes, approximately.

BBA outage evaluation matrix is available in Appendix D.

The location where the disturbance event occurs allows grouping of the outage scenarios into three types to be faced by the communities and which may need to be addressed differently.

Table 2: Types of Outage

Type	Description	No. of communities impacted	Return to Service (RTS) time	Frequency	Maintenance required
1	On main transmission line, before the first community	High	High Transmission line more exposed, requires delay to identify the location and to access, may be severe damage due to storm/icing	Low	Important to build in a large set back and to maintain the clearing and slashing
2	On a transmission line branch feeding community(ies)	Low to Medium	Medium to High Requires delay to identify the location and to access, may be severe damage due to storm/icing	Low	Important to build a large set back and maintain the clearing and slashing
3	On the distribution feeders in the communities	Low	Easier to locate and to access	Medium to High	Monitor and prune problem trees

The following summary table has been developed to assess the impact of the total outage duration on each community and the required autonomy.

Remote Communities

Peak Demand (kW)

		Actual Situation																	Based on Load demand of 2025 (5-year plan)							
Cluster	Communities	LDC	Population	Number of houses	Critical infrastructure in the community equipped with emergency generator							Other infrastructure in the community equipped with emergency generator					Installed community diesel generator	Storage tank capacity	Forecast load demand	Forecast outage duration		Autonomy available (based on storage tank)		Autonomy required to meet forecast load demand		
					SP	NS	A	WT	CC	AR*	SCH*	ST	NR	PS	BO	PW	(kW)	(l)	(kW)	(hr/year)	(% yearly)	(hr/year)	(% yearly)	ENERGY (MWh)	STORAGE (% storage)	GENERATORS (Installed kW)
Red Lake Cluster	Deer Lake	H1RCI	1,320	225	Y	Y	Y	Y	-	N	N	N	N/A	N	N	N	2,095	276,141	1,894	88.75	1.0%	701	8%	168	13%	2,228
	North Spirit Lake	IPA	509	90	N	Y	N	N	N	N/A	N	N	N/A	N	N	N	1,650	651,800	831	96.50	1.1%	3767	43%	80	3%	978
	Poplar Hill	IPA	635	131	Y	Y	Y	Y	N	-	N	N	Y	N	N	N	1,775	602,274	1,075	81.00	0.9%	2693	31%	87	3%	1,265
	Pikangikum	IPA	2,300		N/A	Y	N/A	Y	N/A	N/A	Y	N/A	N/A	N/A	N/A	N/A	3,300	200,670	2,848	65.50	0.7%	339	4%	187	19%	3,351
	Keewaywin and Koocheching	IPA	794	110	N	Y	Y	Y	N	-	N	Y	N/A	N	N	N	1,075	602,270	934	104.25	1.2%	3097	35%	97	3%	1,099
	Sandy Lake	H1RCI	3,048	422	N	Y	Y	Y	N	N	Y	N	N/A	Y	N	N	5,000	406,304	3,872	104.25	1.2%	504	6%	404	21%	4,555
	Red Lake Total		***8,606***	***978***													***14,895***	***2,739,459***	***11,454***							
Pickle Lake Cluster	Kingfisher Lake	H1RCI	594	124	N/A	Y	N/A	Y	N/A	N/A	N	N/A	N/A	N/A	N/A	N/A	1,305	387,048	999	102.25	1.2%	1861	21%	102	5%	1,175
	Wawakepewin	IPA	72	15	N	Y	-	Y	N	-	-	Y	N/A	-	Y	N	306	301,870	203	117.75	1.3%	7128	81%	24	2%	239
	Kasabonika Lake	H1RCI	1,156	175	N/A	Y	N/A	Y	N/A	N/A	N	N/A	N/A	N/A	N/A	N/A	2,000	95,318	1,496	144.25	1.6%	306	3%	216	47%	1,760
	Wunnumin Lake	IPA	694	132	Y	Y	N	Y	N	N	N	N	N/A	N	N	N	2,000	403,405	1,311	128.75	1.5%	1478	17%	169	9%	1,542
	Wapekeka	H1RCI	461	109	Y	Y	N	Y	N	N	N	N	N/A	N	N	N	1,525	100,274	967	125.50	1.4%	498	6%	121	25%	1,138
	Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	H1RCI	1,682	275	N	Y	Y	Y	N	N	Y	Y	N/A	Y	N	N	3,000	150,411	2,148	125.50	1.4%	337	4%	270	37%	2,527
	Bearskin Lake	H1RCI	930	164	Y	Y	N	N	N	Y	N	N	N/A	N	N	N	2,000	290,688	914	133.25	1.5%	1527	17%	122	9%	1,075
	Muskrat Dam	IPA	435	104	N	Y	N	N	N	N	N	N	N/A	N	N	N	1,741	778,405	970	117.75	1.3%	3856	44%	114	3%	1,141
	Weagamow (North Caribou Lake)	H1RCI	1,143	227	N	Y	N	N	N	N	N	N	N/A	N	N	N	1,250	302,634	1,578	110.00	1.3%	921	11%	174	12%	1,856
	Sachigo Lake	H1RCI	930	176	N	Y	N	Y	N	N	N	N	N/A	N	N	N	2,140	250,685	1,035	133.25	1.5%	1164	13%	138	11%	1,218
	Pickle Lake Total		***8,097***	***1,501***													***17,267***	***3,060,738***	***11,621***							
	Watay Total		***16,703***	***2,479***													***32,162***	***5,800,197***	***23,075***							

Legend

Critical infrastructure:

SP: Sewage plant
NS: Nursing station
A: Airport
WT: Water treatment
CC: Community centre

*** Becomes a critical infrastructure if there is no community center:**

AR: Arena
SCH: School

Other infrastructure:

ST: Store or other building
NR: Nursing residences
PS Police station
BO Band office
AR Arena
PW Public works building

N: When presently **not** equipped with emergency generator
Y: When presently equipped with emergency generator
N/A: When information not available
- : When infrastructure not present in the community
When there is a discrepancy between data sources. Information to be validated.

Figure 2: Information on Remote Communities

In order to limit the use of a power backup system and thus provide the community with a more reliable power source, the following considerations must be taken into account:

Table 3: Key Factors to Limit Outages

Key factor	Control means
Limit the number of repairs on the transmission line	▪ Implement a robust design (e.g. steel cross-arm and steel cross-brace, use glass insulators at 115 kV). ▪ Avoid implementation in permafrost. ▪ Rigorous construction supervision. ▪ Rigorous inspection plan more specifically in the first 5 years of operation. ▪ Identify the location subject to woodpecker damage and implement a mitigation plan. ▪ Maintain the clearing and slashing to limit forest fire damage.
Limit the number of trip events	Implement an optimised protection and control scheme to maintain the continuity of service, such as: ▪ Single-pole switching to clear most of the transient faults (80% approx.) without interrupting the service. ▪ Selectivity and coordination of the protection settings. ▪ Install a counterpoise ground when installing the line as required improving ground resistance and limiting the number of lightning trip events).
Limit the trip events duration	▪ Implement troubleshooting tools throughout the SCADA system to quickly identify the root cause of a trip prior to manually reclosing an interrupting device (e.g. Implement fault locator and/or fault distance estimation in relays) to quickly identify the location of a fault). ▪ Standardization of the design, which will facilitate the understanding of the crew during an intervention between substations.
Reduce the restoration time following a transmission outage (Note 1)	▪ Build a maintenance shop at strategic locations supplied with equipment and key spare parts to allow timely repair of the transmission line. ▪ Train and organise lineman crew available in proximity to intervene within acceptable delays. ▪ Consider standby arrangements with helicopter operators to expedite patrols and delivery of materials.
Limit planned outage	▪ Build transmission stations with ring-bus configurations to allow maintaining equipment on the transmission network without interrupting the service. ▪ Implement redundant configuration in substation design (transformers, reactive support, etc.).
Note 1: As understood, a new infrastructure and O&M team would need to be organized since no power line technicians (PLT) are currently available in proximity to the communities.	

Knowing that design, construction and O&M considerations clearly have the potential to impact reliability of the network, BBA is convinced, based on its experience, that outages requiring the backup power system can be reduced up to 50% by implementing the good practices described in the table above in design and O&M of the line.

3.3 Community backup power requirements

Based on the review of the backup power profiles of each community, evaluation of the outage scenario matrix, benchmarking and BBA's experience, the following backup power requirements have been defined:

- If power cannot be provided to homes, furnaces go down and the houses will get very cold quickly, pipes will freeze and damage will occur when they thaw, there will be no ability for electronic communication, cooking will not be possible, food will be lost due to freezers not working (in homes, restaurants and stores), medical supplies (vaccines, etc.) will be destroyed if the fridges are not working, sewage and water supply systems will not function, etc. In addition, people may be in contact with electrical equipment when it is re-energized and will suffer serious injury. Therefore, a community must establish what is critical to remain powered from a safety point of view. The following table highlights what can be considered as critical, essential loads and non-essential loads that can be shed during backup operation. Considering the electrical heating load in all community homes for the sizing of the backup power generator would lead to oversizing of the infrastructure.

Table 4: Critical and Essential Facilities

Critical loads (Managed under the *Emergency Preparedness Plan)*	Essential Loads	Non-essential Loads (Potential shedding load during backup operation)
▪ Nursing station where there is paramedic/nursing employees on a permanent basis ▪ Water/sewer services ▪ Airport ▪ One community meeting place (community center or another building among the essential loads)	▪ Homes ▪ Stores ▪ Police station ▪ School ▪ Band office ▪ Public works building	▪ Electrical heating in homes

The IESO states in their scope of work that as a minimum, critical infrastructure must be covered by the backup power plan. However, to manage the first years of post-connection where outages would be more frequent and will probably last longer due to adjustment on the system once in service, it is recommended to implement a reliable solution to provide backup power to the entire community during longer period of time than what is planned once the system will be tuned.

- Since backup power systems are usually started one hour after a power outage, the scenarios only cover outages that last more than one hour;
- Each community must evaluate their acceptable level of risk to face different types of outages in order to identify their requirements i.e. solution or set of solutions.

3.4 Backup power solutions in other jurisdictions

The benchmarking exercise focused on identifying the technology, approach (centralised by community or distributed / de-centralised) and ownership used in other jurisdictions.

The benchmarking exercise includes taking advantage of BBA's project experience dealing with other utility networks, market knowledge, discussions with different transmission managers dealing with comparable network configurations and/or conditions in the course of this study, as well as available public documentation to gather intelligence on the present market.

The table below represents a portrait of three similar networks that we can use as reference for the backup power plan. In addition, Appendix B presents results from a benchmarking exercise and provides an overview of the potential options that can help in the development of this backup power plan.

Omushkego Ishkotayo - Five Nations | Northern Ontario
DESCRIPTION
Grid connection project (270km of 115 kV line) of Fort Albany, Kashechewan and Attawapiskat with Moosenee Hydro One's facility. Project ended in 2003.
BACKUP POWER TECHNOLOGY
Diesel generators for 2 out of 3 communities connected to the grid
APPROACH
Existing diesel generators were kept as community backups in Kashechewan and Attawapiskat while decommissioned in Fort Albany when the power plant reached its end of life. Diesel generators are rarely used since a section of the transmission line was doubled in 2015. Their capacity was not increased while the load did due to residents converting to electrical heating, thus sequencial load shedding was required during extended outages from the grid.
OWNERSHIP
Existing diesel power plants are now owned by the community and operated by LDC. Maintenance of the generators is shared between the LDC and Five Nations Energy Inc., the transmission line operator.
MISCELLANEOUS
- Reliability was constantly improved due to the installation of redundant transformers, looping of the distribution network, eliminating single points of failure, and construction of a twin transmission line in 2015 that greatly improved source reliability. - The operations manager greatly emphasized the need to design the power line to allow the ability to restore the power easily and rapidly. - The load increased during the first few years partially due to electric heating conversion of houses. - Telecommunication cable was not part of initial project due to financial reasons. It was later part of an agreement with DeBeers to be included in the new power line.

Figure 3: Similar network – Omushkego Ishkotayo

Yukon Energy | Yukon
DESCRIPTION
Islanded network composed of 1100 km of power line, 131 MW of production capacity, Peak load of 82 MW (2015). Base load by hydroelectrical generation, peak load by diesel generators. There is a 20 MW (15min) battery storage, a wind turbine generator (0.8MW) and very few solar panels connected to the grid.
BACKUP POWER TECHNOLOGY
Diesel generators for 10 out of 14 communities connected to the grid
APPROACH
For future production and depending on load growth, they envision NG engine, battery storage, hydro upgrade and refurbishment, small hydro and additional diesel.
OWNERSHIP
Yukon Energy
MISCELLANEOUS
- Not all communities linked to the grid have their own diesel power plant for backup power. - Considering future production requirements, Yukoners prefer several small projects over one large project. - A survey indicated low support for thermal (diesel, LNG). However, many Yukoners said they understood why Yukon Energy is proposing thermal resources for backup and to meet peak demand. - There is broad interest in a variety of Energy technologies, especially wind and solar to further reduce dependence to fossil fuels even if it represents less than 5% annually of total energy produced for the grid. - Genreally, road systems are well developped to transport fuel on site year-round.

Figure 4: Similar network – Yukon Energy

Menihek Hydroelectric Generating Station | Shefferville, Quebec
DESCRIPTION
Islanded network composed of a hydroelectric generating station (16MW capacity) supplying electricity (12MW load) to Schefferville and the Matimekush - Lac John community (60km power line) and then to the Kawawachikamach community (25km power line).
BACKUP POWER TECHNOLOGY
Diesel generators at centralized at Schefferville
APPROACH
Schefferville: centralized diesel backup generator units located at utility substation. Few buildings have local emergency diesel generators. Kawawachikamach: Mainly local emergency diesel generators at major/critical buildings and services.
OWNERSHIP
Distribution network (located in Quebec) owned and operated by Hydro-Quebec Distribution, hydroelectric generating station (located in Newfoundland) owned by Newfoundland power utility.
MISCELLANEOUS
- Diesel generators capacity is lower than the load thus sequential load shedding is required during winter power outage in Schefferville. - No backup is present for the Kawawachikamach community.

Figure 5: Similar network – Menihek Hydroelectric Generating Station

Canadian Public Utility Company | Northern region - Canada
DESCRIPTION
25 off-grid communities located in northern Canadian regions are locally supplied by diesel generators.
BACKUP POWER TECHNOLOGY
Modular self-contained diesel generators
APPROACH
Centralized energy production and backup
OWNERSHIP
The Public Utility owns and operates the generators and distribution network. The Public Utility does not own private building emergency generators.
MISCELLANEOUS
- As a priority, the Public Utility installs these backup generators in communities where larger aircrafts cannot land in an emergency. - Backup diesel generator capacities are sized to feed the largest feeder in the community. - Backup diesel generators can connect to the power station to supplement power if needed. - Upon power conservation conditions, the Public Utility calls out for private generator owners to run them in order to minimize community load requirements from the Public Utility backup generators. - New power plants are being designed to allow future integration of renewable energy sources

Figure 6: Similar network – Canadian Public Utility Company – Northern region – Canada

The following can be considered as an overview of the findings during the benchmarking exercise:

- Most of the remote communities integrated to the grid over the last 20 years in the Yukon, Northern Québec and other northern territories have been radially fed. They usually kept their old diesel installations as a de-energized backup supply, which tend to be almost never used after the integration to the grid (after the first three years where initial issues have been fixed). Due to the high reliability of the grid, some remote communities have decided to decommission their diesel power plants at the end of their useful life and not replace them. However, mitigation means have been put in place to limit the outage duration and recovery time, such as looping configuration of the transmission and/or distribution line, construction of garage to act as a service center, implementing redundant equipment in substations, etc.;
- In the Five Nations transmission networks located in Northern Ontario, it was noted that grid reliability consistently improved over time through measures like installing backup transformers in power stations, looping the network to create multiple sources of current to allow maintenance without power outage, taking care of single point of failures and building a twin line to secure the supply source. The operations manager greatly emphasized the need to design the power line to allow the ability to restore the power easily and rapidly. Note that these design considerations have already been addressed in the current design for Wataynikaneyap Transmission project in form of a ring bus configuration and redundant stepdown transformers;

- Yukon's power grid is an islanded grid in the way that it is not connected to the North American power grid. Yukon Energy produces half of its power from hydroelectric generating stations and half from LNG generators while diesel generators located in communities are conserved mostly for peak demand and backup power. In remote off-grid communities or industrial mining sites diesel is usually the primary source of energy and backup power comprises either separate emergency diesel generators or redundant diesel generators located in the main power plant. Without very large and expensive battery energy storage systems renewables such as solar panels and wind turbines, which only supply a maximum of up to 20-30% of the load are not usually considered as backup power;
- Renewable and alternative energy projects that were undertaken with community engagement and co-investments offered economic development opportunities and social benefits in the communities while reducing their dependence on fossil fuels. Energy storage installations are listed as reference in Appendix B but very few are used for back-up power. Most of the time, energy storage is used for the short period during transfer to another backup source such as diesel or hydro during an outage. They are not in themselves long term energy backup sources yet;
- The replacement of diesel with LNG is also seen in other jurisdictions; however, procurement from the south remains problematic in those areas and the existing installations would all need to be replaced to meet LNG requirements (e.g. storage tank, LNG liquefied plant, etc.), making this an unattractive scenario in the course of the development of a backup power plan.

3.5 Evaluation of available technologies

Various technologies have been studied in order to assess their potential to be selected within the backup power scenarios. Diesel generators, biomass (using steam turbine), hydro, solar, wind and two battery storage technologies have been evaluated on the following criteria:

- Network performance;
- Global conversion (process efficiency);
- Regulatory consideration;
- Environmental consideration;
- Technology maturity;
- Availability of the resource during an outage;
- Autonomy;
- Response time;
- Footprint;
- Lifespan;

- Procurement of resource;
- O&M;
- Investments (CAPEX and OPEX);
- Carbon tax-related fees;
- Local employment opportunities and benefits for the communities;
- Deployment time;
- GHG.

The table can be found in Appendix A.

Diesel generators present the most benefit for being integrated into the backup power plan, while hydro-generating stations are considered if they can also be used for other system purposes (e.g. to provide reactive support to the grid or be operated to generate power for own use/sale). However, on day one, diesel generators remain the technology with the highest viability rate. This evaluation is performed with the information available as of today (related to needs and demand) and considering the actual enhancement of the technology. Considering that need, demand and technology will substantially evolve over the next few years, at which time business cases for other potential solutions should be considered. Examples of the identified business cases are presented in Section 5.2.

This benchmarking exercise should be revisited within the next few years as these technologies are quickly evolving and will shortly experience a turning point, which will make them accessible and viable for such application. For instance, compressed air storage, hydrogen or other types of battery systems have not been considered to date as the technology is considered immature and expensive, especially for remote areas. However, they should be considered in the next round since pilot projects have started, which will provide benchmarking reference in the future.

4. STAGE 2: IDENTIFICATION OF BACKUP POWER SCENARIOS

Among the scenarios identified by the Diesel Backup Study and other potential alternatives raised by BBA expertise with technical and economic considerations, BBA and the project group have shortlisted five scenarios to be further developed to meet the backup power requirements identified.

The relevant backup power scenarios were determined based on the following information identified in the first stage:

- Community backup power requirements: the combined peak loads of the Pickle Lake line will be approximately 11MW in 2025; the Red Lake system will be similar;
- Forecast community outage scenarios, which ultimately provide the required energy storage or autonomy to be considered in the scenario;
- Techno-economic-social evaluation of available technologies that can be used as backup;
- Benchmarking of power systems (used as backup and/or other needs) used in other jurisdictions.

4.1 Scenarios developed

The following scenarios have been shortlisted and will be further developed to meet the backup power requirements identified.

1. Diesel generators must serve 100% of community load demand (full backup);
2. Diesel generators must serve 50% of community load demand (i.e. partial backup which means limiting demand during an outage by shedding some type of load or applying sequential load-shedding scenarios in the event of an extended winter outage to avoid damaging community infrastructure);
3. Existing diesel generators used only until end of life, then only provide critical infrastructure backup;[1]
4. Diesel generators only for critical infrastructure;
5. Multi-community solutions, where one diesel generator may be able to supply multiple communities in lieu of retrofitting/replacing another DGS unit. Clusters of communities being geographically and electrically situated for such scenarios were considered.

[1] Note – in the absence of detailed condition assessment data, this scenario uses the year in which the generator is no longer able to meet 100% of community load demand as a proxy for end of life for the purpose of this report. In reality, some generators may fail or require significant overhauls at an earlier date. In other cases, keeping generators in service past this date may be warranted to provide less than 100% backup as long as maintenance and operating cost remain low. The expectation is that decommissioning decisions would be re-evaluated on a community-by-community basis at regular intervals, based on condition, costs, actual load growth, and operating considerations.

Scenarios	Description	Existing DGS - Actually served by H1RCI	Existing DGS - Actually served by IPAs	Emergency power system for critical infrastructure (Note 1)	Upgrade of community generation capacity	Outage coverage
1	Diesel generators must serve 100% of community load demand (full backup)	Existing generators are considered to be used for the entire project life cycle (40 years).	Replaced at year 0 (to match 100% of load demand in Year 10)	Existing at year 0 for all critical infrastructure.	Adding a new generator when community load demand reaches 85% of installed capacity. When replaced, sized to meet 100% of the load growth 10 years plus, without considering demand growth past Year 40	Back up DGS supplies power for the entire outage period, assumed at 65% of utilization factor.
2	Diesel generators must serve 50% of community load demand	Existing generators are considered to be used for the entire project life cycle (40 years).	Replaced at year 0 (to match 50% of load demand in Year 10)	Existing at year 0 for all critical infrastructure.	Adding a new generator when 50% of community load demand reaches 85% of installed capacity (new generator sized as per half of the load growth 10 years plus, without considering demand growth past Year 40).	Back up DGS supplies power for the entire outage period, assumed at 33% of the Peak Demand.
3	Existing diesel generators used only until end of life, then only providing critical infrastructure backup	Existing generators decommissioned when community load demand reaches 100% of installed capacity.	Use existing generators for their remaining life cycle.	Existing at year 0 for all critical infrastructure. Each critical buildings DGS are sized at 125 kW.	No upgrade of the community DGS.	Before decommissioning, DGS supplies power for the entire outage period, assumed at 65% of the Peak Demand. After decommissioning, Critical Infrastructure DGS supplies power for the for the entire outage period, assumed at 65% of the installed capacity
4	Diesel generators only for critical infrastructure	Decommissioned at Year 0.	Decommissioned at Year 0.	Existing at year 0 for all critical infrastructure. Each critical buildings DGS are sized at 125 kW.	None.	Critical Infrastructure DGS supplies power for the for the entire outage period, assumed at 65% of the installed capacity

Note 1: As per study baseline, all critical infrastructure are equipped with emergency generator. Capital cost at Year 0 to comply with this baseline is presented separately.

Note 2: As discussed further in Section 5.2.1, considering the relative reliance on the prime (transmission) vs backup supply, Scenario 1 leads to over-investment in the backup supply, and is therefore not recommended. Scenario 1 should be considered as a baseline against which the relatives costs and benefits of other scenarios can be compared.

Note 3: In Scenarios 1 and 2, the 85% factor is considered to ensure that generators are always capable of meeting 100%/50% of peak load, with a margin to mitigate risk associated with delays in procurement/installation of replacement generators, as well as risk associated with discrepancies between actual and forecasted load in any given year. This assumption could be revised to be less conservative in future studies.

Figure 7: Identification of Power Backup Scenarios

In addition to the scenarios defined in the above table, the following should be taken into account:

- Existing hydro generating stations should be considered to be connected to the grid and used as backup power during an outage if the application allows (i.e. no freeze up in winter);
- In addition, it is encouraged to pursue the implementation of distributed energy resources ("DER") through incentive programs to reduce overall load on the system.

The preferred approach would be to develop a global network scheme as opposed to only reviewing one community at a time, but does not prevent addressing each community's needs independently. The line damage can occur anywhere along the length of the line. The nearer the "end of line" a community is, the more outages they will experience. The duration of the outage will depend on the accessibility to the damaged section of the line. The further along the line, the longer the outage will be. To mitigate the impact of the outage, a community will require its own source of backup power. However, a single source of power could supply two (or more) communities if they are prepared to accept a slightly higher percentage of outage time (related to the transmission line section connecting communities).

In the event of a power outage, two levels of power supply must be considered:

a) Backup power: A local source of power with frequency-keeping ability that supplies power to all or part of the community in the event of a line outage;

b) Critical Infrastructure (emergency) power: Per the National Building Code (NBC), certain buildings are nominated critical infrastructure. These buildings must (by code) have their own emergency power source (usually a diesel or gasoline generator). This source of power provides minimal power to the building for the duration of the outage to ensure that residents have food, warmth and light when in the emergency shelter building (which could be a gym, arena, band office, community hall, etc.). It is labour-intensive equipment to run but a very low capital cost to purchase and quick to mobilise.

4.2 Additional scenarios

Considering that need, demand and technology will substantially evolve over the next few years, developing business cases for potential upcoming solutions should be considered. The following scenarios that may become quickly more interesting should be considered:

- Hydro-generating stations: Developing large hydro plants can take between 5 and 10 years. The timeline is may be shorter for small hydro plants. Two approaches are possible: either build one or two large plants near the end of the line; or build up to 15 small hydro plants in proximity to each community. Both scenarios may be able to supply power to the grid in the event of an outage and provide reactive support during normal operation. In all cases, it should be validated that the river has substantially more flow than required to power the community.

The business case for hydro-generating stations should consider the following, without limitation:

- The communities' strong interest in economic development opportunities. Being ready when the needs and demands arise is recommended. Small hydro projects are less costly than large hydro which are connected to the transmission network;
- Connection point on the distribution or transmission network (cost, performance, etc.) considering the current climate in Canada, which may provide challenges for constructing hydro with storage facilities;
- Capacity (i.e. available flow) of the river.

Other business cases should also be developed based on the following solutions and technologies, which should be considered at the time of the next study:

- Transmission line looping: Looping the transmission line at a strategic and economic tie-point (e.g. build an 80 km long 115 kV alternate line between Muskrat Dam and Keewaywin). When discussing with transmission network operators, looping in the transmission and distribution networks is a shared valuable approach to enhance flexibility and reduce the outages seen by the end users. For the Wataynikaneyap network, looping could be possible to cover for some outage scenarios. At some point in time where the load demand would reach network operating limits (approx. 2040), load restriction could apply. However, even with load restriction, this solution remains valuable to provide coverage for longer outage scenarios;
- Biomass: If sufficient wood resources are available near a community to sustainably log enough wood to provide the necessary energy, tree-cutting licenses available, capacity and skills exist within the community to operate the plant and community support for logging, biomass could also be considered as an interesting source of backup power, which can also contribute to increasing the network performance (through the use of synchronous machines). However, note that outages usually occur during severe weather conditions. This may not be a good time to start moving wood to a hopper and firing up a complex piece of engineering;
- Solar and Wind: Solar and wind farms by themselves cannot be considered as backup power systems as they presently require expensive large battery energy storage systems (BESS) in order to be considered prime power and thus do not meet the required accessibility criteria of a backup solution. In addition, solar or wind farms should not be seen as a suitable solution since this technology does not present any advantage in improving the network performance. Moreover, the inverter technology used in wind and solar farms may bring some integration challenges, depending if they are connected on the distribution or transmission network.
  As seen in other jurisdictions, wind and solar are therefore not usually considered as part of the backup power but rather as fuel replacement in order to reduce their dependence on fossil fuels.

BBA believes that the above business cases should be developed to assess the potential of those solutions in the medium to long term. Given the timeline to implement, those solutions could not be justified at this time as a solution for day one without further analysis, but BBA believes that some of them can eventually contribute to the backup power plan. Moreover, the cost of technologies such as batteries has reduced dramatically over the years, which may allow defining a business case in future.

5. STAGE 3: PERFORM SCENARIO EVALUATION

The following criteria were identified as relevant to be considered as differentiator factors for the evaluation of the five studied scenarios: cost, capacity to meet demand, outage mitigation and safety.

5.1 Net present cost

To estimate the investment and operating cost for each five scenarios, a net present cost (NPC) analysis was performed for each community. Appendix E presents a summary table of the investment in 2021 dollars. The following assumptions were considered part of the NPC analysis, which can be refined over time with additional available information:

- Usually, the life of a generator is mainly related to the number of hours it has operated and maintenance program performed rather than years of service. For generators used as a backup power system, their life could last for substantially more than 40 years. However, since no maintenance records are currently available for the existing generators, the following has been assumed:
  - For reliability purposes and since no detailed information about the maintenance record sheet and the condition are available, the existing generators with more than 50,000 hours were not considered part of the installed generation capacity;
  - A new generator would be installed in addition to the existing ones when community load demand reaches 85% of installed capacity. Load demand at Year plus 10 is used to size the new diesel generator.
- Generators in H1RCI communities at the time of connection are assumed to remain in service for the entire project life cycle (i.e. 40 years) when used as backup power system and when maintenance is performed as per recommended schedule. An exercise could be carried out in the future to optimise this assumption by implementing an asset management program, i.e. performing a technical assessment of the actual condition of each generator and reviewing their maintenance record sheet. Once community load demand has been reached, generators with a remaining life expectancy could then be installed in another community that requires additional installed capacity;

- Regarding DGS in IPA communities, even though the previous study considers a remaining life of 5 years, the present study considers for most cases (scenarios 1, 2 and 5) replacing them at Year 0 to avoid upgrading the units to meet the new owner's standards as well as to avoid the complication of transferring the ownership to a new entity for the few remaining years before being replaced when they have reached their end of life. For Scenario 3, investing in new DGS at Year 0 is not aligned with the scenario definition in itself, which leads to considering using the existing IPA's DGS until their end of life. Ownership would need to be addressed separately (e.g. IPA could remain active for a few years to own existing DGS for their remaining life);
- For simplicity, as the analysis was not highly sensitive to these costs, critical loads were not forecasted to grow; 125 kW of installed capacity per critical infrastructure was considered, without growth factor;
- The following costs were not considered at this stage of the study stage:
  - Decommissioning cost of existing DGS when applicable;
  - Land and environmental remediation of existing generation facilities;
  - Fuel storage replacement due to wear or to comply with new standards were not considered.
- No longer a need for an N+1 redundancy configuration; N configuration is considered for backup power purposes, i.e. capacity equals peak demand;
- NPC scenarios calculated as a 40-year project; assets have no residual values at Year 40;
- Fuel price forecast (based on the 2014 Draft Remote Community Connection Plan[2]) of $1,360/MWh (in 2023 dollars);
- A real social discount rate of 4% and inflation of 2% as per previous report;
- Utilization factor of 0.65%;
- Replacement Capital Diesel Genset capital cost of $7,500/kW based on information provided by the project (ref AANDC) during the study.

It is worth mentioning that the Replacement Capital Diesel Genset capital cost and the load growth factor both significantly impact the NPC. For most cases, a 50% change on one of those two factors roughly impacts the NPC by 50%.

The following table shows a summary of the NPC by community for each scenario.

[2] http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Remote_Community/OPA-technical-report-2014-08-21.pdf

SCENARIOS		EVALUATION CRITERIA			SAFETY
No.	**Description**	**Net Present Value[1]**	**Capacity to meet community load demand**	**Outage mitigation[2]**	
1	Diesel generators must serve 100% of community load demand	High	Highest Meets 100% of the community load demand for 40 years	Essential loads are covered for outages occurring on the transmission line (Types 1 and 2) Critical infrastructure are covered for Types 1, 2 and 3	Minimal safety concern
2	Diesel generators must serve 50% of community load demand	Medium	Medium Meets 100% of the community load demand for the first years, then at least 50% of the demand through a load shedding scheme to be implemented	Essential loads are covered for outages occurring on the transmission line (Types 1 and 2) Critical infrastructure are covered for Types 1, 2 and 3	Increase the risk due to the use of alternative heating source
3	Existing diesel generators used only until end of life, then only providing critical asset backup	Medium	Medium to Low Meets 100% of the community load demand for the first years until load demand reaches the installed capacity; the service is then curtailed.	Covers outages occurring on the transmission line (Types 1 and 2) for only a few years Critical infrastructure are covered for Types 1, 2 and 3	Increased risk due to the use of alternative heating source Increased risk due to the use of portable generators (intoxication from CO) for the ones that do not have access to minimum backup service
4	Diesel generators only for critical infrastructure	Low	Low Coverage for critical infrastructure only, no coverage for community load demand for the entire 40 years.	Critical infrastructure are covered for Types 1, 2 and 3	Potential for community-wide issues with respect to heating and sanitation issues requiring increased emergency response efforts. Increase the risk due to the use of portable generators (intoxication from CO) for the ones that do not have access to minimum backup service
5	Multi-community solutions, where one diesel generator system supplies 100% of load demand for all communities	Mostly equivalent to Scenario 1	High Meets 100% of the community load demand for 40 years through cluster configuration.	Essential loads are covered for outages occurring on the transmission line (Type 1) but not for Type 2 since outlying communities may be cut-off from central DGS Critical infrastructure are covered for Types 1, 2 and 3	If the interconnection network between communities is unavailable: Potential for community-wide issues with respect to heating and sanitation requiring increased emergency response efforts. Increased risk due to the use of portable generators (intoxication from CO) for the ones that do not have access to minimum backup service

Note 1: Refer to Appendix E for detailed NPC per community per scenario.

Note 2: Refer to Table 2 in the report "Types of Outage Scenarios"

Figure 8: Evaluation Criteria

5.2 Analysis and recommendations

The intent of this report is not to recommend one scenario applicable for all communities or recommend a scenario per community, but to provide the relevant information to the First Nations and stakeholders to allow them to make the right decisions and plan the post-connection period according to their own economic and social development plan, which has not been communicated as part of this study.

5.2.1 By scenario

Scenario 1 provides the most coverage to the community by installing backup power to meet 100% of the community load demand over the entire 40 years of the project. This requires installing large generators, which involves substantial investment. For instance, at Sandy Lake, total diesel generators capacity of 18 MW would be required to meet 100% of the demand in 2060, for a NPC in 2021 dollars of $82M with investment each 10 years starting in 2028). The total NPC cost of Scenario 1 is $575M. This is a significant amount of money, which can probably be better invested in alternative solutions for network reliability improvement. Consequently, Scenario 1 would soon lead to over-investment in the backup system compared with investment in prime supply, and is not recommended.

For Scenario 1, based on this study, the following communities would need to invest in their community DGS during the first year to meet load demand: all IPA communities, Kasabonika Lake and North Caribou Lake. In 2023, Deer Lake would be the next one before further communities a few years later.

Scenario 2 provides sufficient installed capacity to meet 50% of the community load demand. Initially, existing diesel generators would provide full back up until load growth reaches 85% of the installed capacity where the backup capacity will be reduced and maintained at 50%). Such a partial backup scenario could be considered in a configuration with substantial investment, the electrical heat, for instance, can be shed during an outage and houses rely on their conventional backup heating system (e.g. wood or oil). Alternatively, sequential load shedding, as previously seen in some communities, could be applied (feeder by feeder). Otherwise, it does not seem a viable approach for a community service provider to offer partial backup power to its community. The total NPC cost of Scenario 2 is $248M, which does not include the additional investment in specific load shedding technologies, and would therefore require operators to implement sequential load shedding.

From a cost perspective, except for the IPA communities that would still require investment at Year 0, the generator capital cost could differ by ten years compared with Scenario 1.

Scenario 3 considers using the existing DGS (in H1RCI communities) until community load demand reaches 85% of the installed capacity (as an alternative in a future analysis, this could also be used until end-of-life with load shedding scenario) at which point only critical infrastructure would be served. In this scenario, only Kasabonika Lake and North Caribou Lake (H1RCI) would require capital investment during the entire 40-year period. The total NPC cost of Scenario 3 is $41M, and this scenario would allow coverage for more frequent and longer outages that communities will have to face over the first years of service of the transmission line. Afterward, only the critical infrastructure would be equipped with backup diesel generators.

Scenarios 1, 2 and 3 would all allow coverage for more frequent and longer outages that communities will have to face over the early years of service of the transmission line.

Scenario 4 does not involve any community backup system, only critical infrastructure equipped with their emergency diesel generators. The community DGS would not be transferred and would be decommissioned. This scenario is the one with the lowest investment ($31M), but does not provide any coverage during outage for the community at any time after connection.

Scenario 5 would require the construction of a centralised DGS and interconnection of clusters of communities using a distribution line from community to community. As a full backup solution does not use the prime network (i.e. transmission network), an alternative path should be considered. If a transmission network is used, large hydro (larger than 8 MW) would need to be considered as a partial backup solution.

The following clusters have been identified for this scenario:

- Kitchenuhmaykoosib Inninuwug (Big Trout Lake) and Wapekeka (and maybe with Wawakapewin and Kasabonika): Kitchenuhmaykoosib Inninuwug (Big Trout Lake) and Wapekeka communities, the DGS in Kitchenuhmaykoosib Inninuwug have the capacity to support both communities for the first years;
- Sandy Lake, Keewaywin, North Spirit: Sandy Lake is the largest H1RCI community, and Keewaywin is a smaller IPA community;
- Wunnumin and Kingfisher Lake: Relatively close, Kingfisher is an H1RCI community and Wunnumin an IPA;
- Deer Lake, Pikangikum, Poplar Hill.

This scenario could allow reducing the investment when installed capacity is higher than the load demand but would leave communities in the cluster vulnerable should the distribution connection fail along with the transmission line. The NPC is not deemed accurate enough to be presented with the information available, but the analysis does not indicate any significant savings or benefit to be further considered.

In all scenarios, it is recommended to consider making provision for automatic load shedding with load type and customer priority in each community prior to connecting to the grid. This would be highly beneficial when facing high growth rate or to easily adapt to different backup solutions to minimise the investment and to afford contingency conditions.

Considering a Replacement Capital Diesel Genset Cost of $7,500/kW based on information provided by the project (ref AANDC) in the course of the study (even higher in some cases), before installing new diesel generators, when community load demand is reached starting in 2025, a business case should be performed to consider other technology.

5.2.2 Emergency power for critical infrastructure

Regarding backup generator requirements for critical buildings, some communities would need to invest now to comply with CSA standards (C282, Z32) and the National Building Code (NBC) of Canada. Appendix E provides budget estimate per community to bring each critical infrastructure compliant with actual standards. The condition of the existing backup generators is currently unknown and would need to be assessed. Replacement cost for the existing backup generators would then need to be considered, which was not assessed in the present study.

6. OWNERSHIP AND OPERATION

Based on the benchmarking exercise and BBA's experience, the ownership of the backup power infrastructure can take several different approaches. Ownership of the back-up power can be by in the community, the LDC and/or the Transmitter.

In other jurisdictions, having the Transmitter accountable, for the backup plan, can be more efficient in terms of capital expenditure and operations. However, in Ontario, the regulation does not allow a Transmitter to own or operate generation. This limits the contribution of the Transmission line operator.

Transferring the ownership of the equipment initially owned by H1RCI could require substantial regulatory and legal effort, which would be avoided if H1RCI retains ownership. Note that an entity who owns the generation assets will not necessarily be directly be responsible for the costs associated with operation and maintenance of the facility. Those costs can be shared with or totally assumed by another entity.

The previous report (Section 6) provided a detailed analysis of the potential challenges that should be considered to establish the ownership and operation structure.

Developing the ownership and operation structure must be addressed separately in a subsequent study with the different parties involved.

7. CONCLUSION

The current study was commissioned by Wataynikaneyap Power to provide information that could be communicated to relevant stakeholders and First Nations to facilitate future dialogue. The study scope included consideration of backup supply issues assuming the connection of 16 communities to the grid starting in 2021.

Diesel is considered the only efficient technology currently available to provide reliable backup power services on day one after connection. Hence this study has focussed on the use of diesel generators in the five scenarios considered. Other power sources could contribute to the backup plan, but implementation time and cost were constraints in the development of the business case.

Reactive power support will likely be required in 2030. So, investment in synchronous machines could provide common benefits for both backup power during outages, and reactive power support during normal operation of the transmission system. (starting in approximately 2030). A long-range reactive power compensation study completed during the course of this backup power study has confirmed the necessity of reactive power support. The next update of this study, recommended to occur before 2025, should consider potential common use of reactive support and backup power needs.

A backup power system should not fully substitute the prime supply, leading to more investment in the backup power system than in the prime supply, money that could probably be better invested in alternative solutions for network reliability improvement. The intent of the backup power system should be to provide a backup power service that meets each community's needs when considering the various outage scenarios. The seven IPA communities will require investment in backup power immediately after connection. Kasabonika Lake, Weagamow and Deer Lake also need to identify their preferred scenario for a backup power plan since they will be the first H1RCI communities reaching installed capacity within the study period (before 2025) t. In addition, Kasabonika and Big Trout Lake have less installed storage capacity (47% and 37% of capacity respectively, based on estimated outage duration), which may require upgrade and should be assessed in the short term.

8. RECOMMENDATIONS

Backup power planning must also consider community preferences. The following recommendations have been provided to allow the development of a backup power plan that meets each community's needs:

- During the Project design phase, ensure that transmission line design integrates best practices to minimise outage scenarios (as presented in Table 3);
- Develop grid outage response recommendations that can be integrated into community Emergency Preparedness Plans;

- Refine capital investment estimates by reviewing available community infrastructure data to verify completeness and eliminate discrepancies;
- Identify viable alternative technologies (i.e. renewables) considering the high replacement cost of diesel generators (average $7.50 per installed Watt). Then re-evaluate the costs of these technologies periodically to determine whether and when business cases are worth pursuing with consideration of available incentive programs, transmission line performance, VAR support requirements, capacity requirements, socioeconomic benefits, etc.;
- Achieve consensus on responsibilities for investment, ownership, and operations and maintenance of backup supply options throughout the life cycle of the project;
- Regularly review NPC assumptions. The load growth factor (4%) and the replacement diesel generator capital costs significantly influence the NPC, so it is important to keep these accurate and updated;
- Evaluate the requirements for implementing automatic load shedding with load type and customer priority in each community prior to connecting to the grid. This would be highly beneficial when facing high growth rates or to easily adapt to different backup solutions to minimize the investment and to afford contingency conditions;
- This study should be revisited few years after connection date (before 2025), once historical outage duration and frequency data is available. Load growth should be reviewed based on new living habits of the communities post-connection (such as the use of electrical heating). Additional data should be gathered on the existing diesel generator’s condition, and business cases developed to consider new technologies. This backup power plan study should be considered as part of planning and decision making around near term investments in remote First Nation diesel generating systems.

Ultimately, each community must establish what is critical to remain powered from a safety point of view and evaluate their acceptable level of risk to face different types of outages in order to identify their requirements, i.e. solution or set of solutions

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Appendix A: Evaluation of Available Technologies

	Diesel generator	Biomass (Steam turbine)	Hydro generator (run-of-river)	Solar panel (PV)	Wind turbine generator	Storage – Battery Lead Acid	Storage – Battery Li-Ion
1. Network performance							
1.1 Short-circuit contribution for protection coordination and power quality	Good	Good	Very good	Poor	Poor	Poor	Poor
1.2 Frequency control	Very good	Poor - to - Fair	Very good	Poor or inexistent	Poor or inexistent	Poor or inexistent	Poor or inexistent
1.3 Reactive support (Voltage support)	Very good	Very good	Very good	Good	Good	Good if present	Good if present
1.4 Spinning reserve	Yes when synchronized with the grid	Yes, but slow to react	Yes	Emulated	Emulated	Emulated	Emulated
2. Global conversion (Process efficiency)	Poor (33%) whitout heat recovery [3.45 kW/L [2]]	Comparably poor without the heat recovery	Very good	Good when available	Good when available	Poor, because of double conversion (Cycle charging efficiency)	Poor, because of double conversion (Cycle charging efficiency)
3.Environmental consideration	GHG emissions, risk of fuel spills, noise pollution, reduced social acceptance	GHG is carbon neutral, noise pollution, improved social acceptance	GHG during construction, aquatic impacts are mitigable, socially supported	Footprint is scale=dependent, PV cell disposal at the end of life, socially supported	Visual and noise pollution, improved social supported	Hazardous waste disposal at the end of life, improved social supported	Disposal at the end of life, improved social supported
4. Technology maturity	Very high	High	Very high	Average	Average	Low	Low
5. Availability of the resource during an outage	Immediate, if fuel reserve has not been used for another purpose than backup purpose and if fuel is in good condition.	Immediate if feedstock is available	Immediate, except in case of annual frazil ice where the generator could be unavailable for one day or so	Intermittent, dependent on the sun.	Intermittent, dependent on the wind forecast.	Immediate if loaded	Immediate if loaded
6. Autonomy	Many hours, Dependant on the fuel storage size, refill capability and connected load. [Utilisation factor of 90%]	As high as feedstock is available [Utilisation factor of 80%]	Many days, as long as the river is not frozen (site selection should be done accordingly) [Utilisation factor > than 60%]	Low, must be installed with storage [Utilisation factor of 40%]	Low, must be installed with storage and not available below 30 deg C [Utilisation factor of 40%]	Low, not well-scaled to MW for many minutes. Must be recharged (hours) before re-use. [Utilisation factor of 40%]	Low [Utilisation factor of 40%]
7.Response time (delay before power can be restored to community)	Very fast (few minutes/seconds)	Very slow, 6 hours after cold start. Available if used in stand-by / interconnected mode	10 minute delay, if at standstill and already available if used in interconnected mode	Readily available if used in interconnected mode and sun is shining	Readily available if used in interconnected mode and wind is blowing	Readily available if used in interconnected mode and charged	Readily available if used in interconnected mode and charged
8.Footprint	Small	Medium	Medium	Large	Large	Small	Small
9.Lifespan	Long, if only used in backup [30 years]	Long [20-25 years]	Very long [40 years min]	Average [20 years]	Average [20 years]	Low [5-10 years]	Low [5-10 years]
10.Procurement of resource (from South, not locally)	Annual when used with proper sized fuel storage	Annual if needed	N/A	N/A	N/A	N/A	N/A
11.Operation and maintenance (frequency and level of complexity of the required manpower)							
11.1 Operation (daily/weekly involvement)	Simple	Medium-to-High	Simple	Simple	Simple	Simple	Simple
11.2 Maintenance	Simple	High	Medium	Medium	Medium	Medium	Medium
12.Initial investment (CAPEX) - 1 MW installed	$ Low in case of standby unit at 1800 rpm [1.2-1.6 M$]	$$$ Moderate especially for feedstock storage [4-5 M$]	$$$ Moderate, because of the infrastructure [4-5 M$]	$$$ Moderate [5-7M$]	$$ Moderate [3-4 M$]	$$$ High [8-10M$ for installed 5-6 MWh]	$$$ High [10-12M$ for installed 5-6 MWh]
13.Operation cost (OPEX) - 1 MW installed	High	Moderate	Low	Low	Low but high tech staff	Moderate, but high tech staff	Moderate, but high tech staff
14.Carbon tax related fees	To be considered, but less important if standby only	Minimal and temporary during installation	Construction phase is carbon intensive, but temporary	Minimal and temporary during installation	Minimal and temporary during installation	Minimal and temporary during installation	Minimal and temporary during installation
15. Local employment opportunities and benefits for the communities	Low	High	Average	Average	Average	Low	Low
16. Deployment time	1 year project	2 year project	5 year project	2 year project	3 year project	1 year project	1 year project
Life Cycle analysis of GHG Emissions (20 year period) - if used as a main energy source and not as back-up (kg CO2 eq./MWh) [1]	1059	316	15	43	10	16	16

References:
1: Yukon Energy's 2016 Resource Plan, June 2017

Appendix B: Benchmarking Exercise Results

PROJECT NAME AND LOCATION	DESCRIPTION	TECHNOLOGY	BACK-UP TECHNOLOGY	APPROACH	OWNERSHIP	MISCELLANEOUS	REFERENCES
Lubicon Lake First Nation | Little Buffalo, Alberta	Grid connected community. Installation of a 20kW Solar PV farm to heat and light a community health center.	Solar panels	No mention of backup power in available documentation.	N/A	Many private and public contributors to raise 45k$.	Allowed to educate local population and participation in installing solar pannels. This project is aslo seen as a new way forward in a land that have seen detrimentals impacts from oils spills in Alberta.	http://www.cbc.ca/news/canada/edmonton/lubicon-lake-first-nation-using-solar-to-power-health-centre-1.3199688
Vuntut Gwitchin Government | Old Crow, Yukon	Off-grid diesel generation network. 1.1MW diesel power plant. New 400 kW Solar PV farm project including battery storage.	Solar panels	Diesel	Centralized (only one village)	Local First Nation Government would own the renewable solution. Atco Electric Yukon would purchase the power by means of a Power Purchase agreement, and would own and operate the energy storage and generation control system. Yukon and Federal Gvnmt would support project so renewable solution does not caus power rate increase over life of project.	The aim is to build renewable energy source to displace diesel power generation, lower GHG emissions and create local jobs and training opportunities.	http://www.atcoelectricyukon.com/Renewables/Displacing-Diesel
Lutsel K'e, | Northwest Territories	Off-grid diesel generation network. Diesel power plant. 300 inhabitants. Installation of solar panels representing up to 20% of village consumption (more realistically10-15%).	Solar panels	Diesel	Centralized (only one village)	350k$ for 35kW solar array. Owned by the community, with help of Bullfrog Power, ecoEnergy for Aboriginal 100k$ grant, NWT government grant. Agreement with NWT Power Corporation for diesel solar power offset.	Involvement of the entire Lutsel K'e community has led to pride of ownership of the new solar PV system. Four community members completed the five-day solar training course and two of these elected to work on the installation. Students in Grades 7 -12 learned about and discussed the new electricity generation system with the installers, AEA and the Lutsel K'e Dene First Nation senior administrative officer.	https://www.canada.ca/en/polar-knowledge/publications/polarleads/vol1-no4-2016.html http://www.cbc.ca/news/canada/north/lutsel-ke-power-business-1.3602415
Raglan Mine | Nunavik, Quebec	Off-grid network. Based on diesel power to supply electricity and heating. Load is much higher than a single village.	Diesel generators. 1x3MW wind turbine, 200kW Hydrogen 20h, 200kW battery 74min, 250 kW flywheel for 27 sec.	Diesel	Centralized (only one camp/mine site)	Privatly own. 18.9M$ wind demonstration project including 7.8M$ grant. Diesel power plant is privatly owned.	Demonstration project in conjunction with NRCan. Sub-grid in a micro grid to emulate 50% penetration of wind turbine. Hydrogen technology is not mature yet for remote cold climate.	
Ramea Island | Newfoundland	Off-grid wind-hydrogen-diesel energy system. Will allow shutting down diesel generators during low energy demand period.	Wind, Hydrogen, Diesel	Diesel	Centralized	Newfoundland and Labrador Hydro		
Hornepayne Sawmill, Co-Gen Plant | Ontario	Modernization of an existing sawmill and biomass cogen of 10 MW.	Cogen using sawmill residue	No mention of backup power in available documentation.	N/A	Alliance with three first nation communicites for 30% stakes in Hornepayne, who bought former sawmill from bankruptcy in 2016. 4M$ investment for modernization.	Sawmill employ 90 poeple, co-gen 17.	https://www.northernontariobusiness.com/industry-news/forestry/first-nations-take-ownership-stake-in-hornepayne-sawmill-co-gen-plant-778712
Fort McPherson Biomass Heating Project | NWT	Off-grid network with diesel generation. Biomass district heating system using locally harvested willow. Provide heat to bank office and selling heat to local health centre. 900 habitants.	Thermal biomass	No mention of backup power in available documentation.	N/A	Community own	Although thermal biomass is not applicable as ther is no electricity generation: the project align with traditional practices, cultural values and build local capacity and self-reliance, as harvesting and working with wood is an important part of the culture. When renewable and alternative energy projects are undertaken with earnest community engagement and co-investment they offer great opportunity to decrease northern dependence on imported fossil fuels, while fostering economic development and social benefit in northern communities.	https://www.canada.ca/en/polar-knowledge/publications/polarleads/vol1-no4-2016.html
Pagnirtung | Pagnirtung, Nunavut	Off-grid network. Diesel power plant 2x1300 + 1x680kW. Power plant caught fire. Emergency generator was not sufficient: Qullic Energy Corporation sent temporary diesel generators by plane for the two years of reconstruction	Diesel	Diesel emergency generator (725kW / 22%)	Centralized (only one village)	Qulliq Energy corporation owns and operates power plant. QEC is 100% own by Nunavut.	25 independant diesel power plants. No backup electrical network. No energy source nor regional distribution. Highly depend on fossil fuel	https://www.qec.nu.ca/node/191
Grise Fjord | Grise Fjord, Nunavut	Off-grid network. Diesel power plant 4x200kW. Power plant replacement. Backup is one of the 4 units	Diesel	Redundant diesel generator is considered backup (200kW / 25%)	Centralized (only one village)	Qulliq Energy corporation owns and operates power plant. QEC 100% own by Nunavut.	25 independant diesel power plants. No backup electrical network. No energy source nor regional distribution. Highly depend on fossil fuel	
Off grid mine | Meliadine, Meadowbank, Nunavut	Off-grid network consisting of a diesel co-generation power plant	Diesel	Redundant diesel generator is considered backup	Centralized (only one camp/mine site)	Private companies	Backup power is from emergency or N+1 generator set in power plant.	
Whitesand First Nation - Biomass | Ontario	Off-grid network. 3.6 MW wood cogenerator biomass project. Including a Diesel backup (less than 1% / yr) for maintenance and emergency	Biomass cogeneration power plant	Diesel	Centralized	The plant is community owned and operated. A 20 years renewable agreement was necogiated to secure financing for electrical generation. Government of Canada support of $1.1 million provided by Natural Resources Canada (NRCan) under its Indigenous Forestry Initiative through the federal Strategic Partnerships Initiative Community Opportunity Readiness Program, Indigenous and Northern Affairs Canada has provided $1.8 million FedNor's investment of $949,539 is provided through its Northern Ontario Development Program $949,539 is provided through the Northern Ontario Heritage Fund Corporation.	Wood pellet plant provide employement to 60 persons. Project under study since 1995	http://www.cbc.ca/1.4365135
Wemontaci | Quebec	Remote community connected (2008) to the power grid. Local diesel generators were then decommissioned.	Grid connection	Decommissioned diesel generators	N/A	N/A	Community has an emergency plan for survival of the people in case of a major power outage and critical/important buildings have their own diesel generators.	

ENERGY STORAGE INSTALLATIONS	POWER CAPACITY [MW]	STORED ENERGY [MWh]	PROJECT COSTS [$M]	APPLICATIONS
Flow Battery System				
Puerto Rico Electrical Power Authority (PREPA) – Puerto Rico	20	14	20.3	Frequency regulation Spinning reserve
Berliner Kraft-und Licht (BEWAG) – Berlin, Germany	17	14	14	Frequency regulation Spinning reserve
Golden Valley Electric Association (GVEA) – Fairbanks, Alaska USA	27	14.6	35	VAR support Spinning reserve Power system stabilization
AES Gener – Atacama Desert, Chile	12	N/A	N/A	Frequency regulation Spinning reserve
BC Hydro – Field & Golden, BC Canada (under construction)	1 each	N/A	N/A	Reduce peak-energy load Replace need for back-up generation
Sodium-Sulphur Battery System				
J Power – Subaru Wind Farm in Tomahae, Hokkaido, Japan	4	6	N/A	Wind energy storage Wind power stabilization
Hydro Tasmania - Huxley Hill on King Island, Tasmania Australia	0.2	0.8	N/A	Load levelling Wind energy storage Diesel fuel replacement
PacifiCorp – Castle Valley, Utah USA	0.25	2	1.6	Distribution line upgrade deferral Voltage support
Detroit Edison – Akron & Lum, MI USA	0.2	0.4	N/A	Peak shaving Voltage sag support
Sodium-Sulphur Battery Energy Storage Installations				
Japan Wind Development – Futamata in Aomori Prefecture, Japan	34	N/A	N/A	Wind energy storage Wind power stabilization
New York Power Authority – Long Island, New York USA	1.2	6.5	2.5	Load shifting
American Electric Power – N. Charleston, W. Virginia USA	1.2	7.2	4.3	Wind power stabilization Peak shaving
Presidio, Texas USA	4	32	25	Back-up power Load levelling
Luverne, Minnesota	1	N/A	N/A	Wind power stabilization Wind energy storage
Flywheel Energy Storage System				
ISO New England, New England, Massachusetts, USA	3	N/A	N/A	Pilot Program
Beacon Power Corporation,Stephentown, New York, USA (under construction)	20	5	69	Frequency regulation of the state electric grid
Diesel Rotary Uninterruptible Power Supply (DRUPS)				
Canadian Meteorological Centre – Dorval, Quebec Canada	N/A	N/A	N/A	Meteorological Centre
Montreal Data Center – Montreal, Quebec Canada	7 x 2.25 MW	N/A	N/A	Data Centre
365 Main – San Francisco, California USA	10 x 2.1 MW	N/A	N/A	Data Centre
Horizon – NoVa One Data Centre in Manassas, Virginia USA	25 x 2.1 MW	N/A	N/A	Data Centre
Pumped Reservoir Energy Storage Installations				
Ontario Power Generation – Sir Adam Beck Pump Generating Station in Niagara Falls, ON Canada	174 total	N/A	N/A	N/A
US Bureau of Reclamation – Grand Coulee Dam in Coulee City, WA USA	400 total	N/A	N/A	N/A
New York Power Authority – Lewiston Pump Generating Plant in Lewiston, NY USA	200 total	N/A	N/A	N/A
Brookfield Renewable Power Inc. – Bear Swamp	2 x 320	N/A	N/A	N/A
Compressed Air Energy Storage				
Alabama Electrical Corp., McIntosh, Alabama	110	N/A	65	Salt Dome of 538000m³
E.N Karftwerk, Huntorf, Germany	290	N/A	N/A	Salt Dome of 300,000m³
Hydrogen Production/Storage				
Newfoundland and Labrador Hydro, Ramea, NL Canada	0.25	N/A	N/A	Wind energy storage
Xcel Energy & NREL, Boulder, Colorado USA (Pilot Project)	N/A	N/A	N/A	Wind energy storage
Raglan Mine, Nunavik, Qc. Canada	0.2	4	N/A	Wind energy storage - Demonstration program

Appendix C: Community Assets and Infrastructure Summary

Summary of Backup Power Planning Sheets

Community:		Q1- Emergency Power Outage Plan?	Q2 - If yes, what is the plan?	Q3 - Buildings	School					Band Office					
				Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?
Bearskin Lake	1	Yes	Keep all generators running as long as possible, when safe to do so, within safety limits and policy; advise the Community Emergency Response Team of the status of the generators, or if there is a pending shut down of Hydro services; Communicate with	No						No					
Deer Lake	2	No		No						No					
Keewaywin	3	No	Keewaywin will have backup generators (total of 3)	No		backup lights (battery)				No					
KI	4	No		Yes	Battery	Yes	Yes	Yes	Yes	No					
North Caribou Lake	5	No		No						No					
Poplar Hill	6	No		No						No					
Sachigo Lake	7	No		No						No					
Sandy Lake	8	Yes		Yes, both elementary and high school	5 + years	Yes	Yes	No, main lights	Janitors	No, the BO has emergency lighting		Emergency lights are operated by battery			Trevor
Wapekeka	9	No plan in place as of yet		No						No					
Wawakapewin	10	No		No school		Yes	Yes	Yes	Ryan Jung	No		Yes	Yes	Yes	Ryan Jung
Wunnumin Lake	11	The community of Wunnumin Lake do not have an Emergencey Power Outage Plan. Wunnumin Lake is an IPA community and had chosen not to have a plan.		No						No					
Muskrat Dam	12	No		No						No					
North Spirit Lake	13	INCOMPLETE													
Kasabonika	14	INCOMPLETE													
Kingfisher	15	INCOMPLETE													
Pikangikum	16	INCOMPLETE													

Community:	Arena						Sewage Treatment Centre						Water Treatment Centre					
	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?
Bearskin Lake	Yes						Yes; at this time it only operates when the weather is warm. Issues		Yes		Yes	Plant Manager	No					
Deer Lake	No						Yes, not operational	Cummins 80 kilowatts	Yes		Yes	Operators	Yes	Cummins 100 kilowatts	yes	yes	yes	Operators
Keewaywin	No						No						Yes		Yes	Yes	Yes	Water Treatment Plant Operators
KI	No						No						Westend, yes; Mainland, no	diesel	Yes	Yes	Yes	?
North Caribou Lake	No						No						No					
Poplar Hill	No						Yes, DGS	Cummins, 20 kW, shared DGS	Yes	Yes	Yes	Ken Strang, Patrick Owen	Yes, DGS	Cummins, 20 kW. Shared DGS	Yes	Yes	Yes	Ken Strang, Patrick Owen
Sachigo Lake	No						No						Yes	Gen Make: Onan, Gen model: 100DGDB/80392K Gen serial			Yes	Cummins Mid-Canada Ltd. 489 Oak Point Hwy Winnipeg, Man R3C 3R1, ph # (204)632-5470, fax (204) 697-0367, servicing
Sandy Lake	No						No						yes	97	Yes		Yes	yearly check ups
Wapekeka	No						Yes	600 volts, 17 years, solar panels not working	Yes	Yes	Yes	Plant Maintenance	Yes	3 phase generator	Yes	Yes	Yes	Plant Maintenance
Wawakapewin	No						No		Yes	Yes	Yes	Ryan Jung	Yes		Yes	Yes	Yes	Ryan Jung
Wunnumin Lake	No						Yes						Yes	150 watts, Onon, Cummins Power Generation.			It provides full service power	Clifford Mamakwa and Ronnie Martin look after the water plant. If they are unable to fix the generator. Someone is
Muskrat Dam	No						No						No					
North Spirit Lake																		
Kasabonika																		
Kingfisher																		
Pikangikum																		

Airport

Community:	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?
Bearskin Lake	No					
Deer Lake	Yes	Trailblazer 440 Miller	Yes	Yes	Yes	Airport Foreman Mechanic
Keewaywin	Yes		Yes	Yes	Yes	MTO
KI	Yes					MTO
North Caribou Lake	No					
Poplar Hill	Yes, DGS	Kohler, 20 kW, 1989	Yes	Yes	Yes	Phil Howe, Robin Donsford
Sachigo Lake	No					
Sandy Lake	Yes		Yes	Only powers necessary lights. It probably can power heat	Yes but they only use it to power the lights and runway lights,	MTO worker. Forrest Kp
Wapekeka	No					
Wawakapewin	No					
Wunnumin Lake	No					
Muskrat Dam	No					
North Spirit Lake						
Kasabonika						
Kingfisher						
Pikangikum						

Community Centre

Community:	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?
Bearskin Lake	No					
Deer Lake	No					
Keewaywin	No					
KI	No					
North Caribou Lake	No					
Poplar Hill	No					
Sachigo Lake	No					
Sandy Lake	No if the power goes out they close the building					
Wapekeka	No					
Wawakapewin	No					
Wunnumin Lake	No					
Muskrat Dam	No					
North Spirit Lake						
Kasabonika						
Kingfisher						
Pikangikum						

Public Works Building

Community:	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?
Bearskin Lake	No					
Deer Lake	No					
Keewaywin	No					
KI	No					
North Caribou Lake	No					
Poplar Hill	No					
Sachigo Lake	No					
Sandy Lake	No					
Wapekeka	No					
Wawakapewin	No					
Wunnumin Lake	No					
Muskrat Dam	No					
North Spirit Lake						
Kasabonika						
Kingfisher						
Pikangikum						

Community:	Nursing Station						Police Station						Store 1/Organization with a backup genera				
	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?	Who Maintains?	Backup Generator?	Size, Type, Age	Emergency Lighting?	Heating/Cooling?	Full Service?
Bearskin Lake	Yes						No										
Deer Lake	Yes		Yes	Yes	Half of the building	Caretaker	?										
Keewaywin	Yes		Yes	Yes	Yes	Health Canada	No		Backup lights (battery)				Northern Store		Yes	Yes	Yes
KI	Yes	Diesel	Yes	Yes	Yes	?	Yes	Cannot give out info	Yes	Yes	Yes	?	Tikinagan		Basic needs lights		
North Caribou Lake	Yes						?						?				
Poplar Hill	Yes, DGS	20/300 kW, Kohler, 2015	Yes	Yes	Yes	Daniel Moose	No						Nurses' residence	20/300 kW, Kohler, 2015	Yes	Yes	Yes
Sachigo Lake	Yes	Pritchard Engineering Co. Ltd Winnipeg, Man. Canada Model # AD25D5.1 Serial # 39608690 RPM 1800,			Yes	Health Canada, Sioux Lookout Zone, maintenance PRG, Mat @ 737-6097, Leo Tait @ Sach. 595-2500	No										
Sandy Lake	Yes					Greg Linklater	Yes	not sure	Yes	Yes	Yes	Maintenance guy Gary Zimmerman in Thunder Bay ("parts	Air Sandy	10 years old	Yes but their main concern is the fridges and freezers	No	Probably but it is used of they expect like a full day power outage
Wapekeka	In Process	Unknown	Yes	Yes	Yes. Has to be the whole building		No										
Wawakapewin	No nursing station						No Police						FroggMart = Yes				
Wunnumin Lake	Yes	1988, AC Generator, Newage Sharp Ford			It provides full service power	The nursing station custodian maintains the equipment. Once the generator breaks down. Health Canada is notified	No										
Muskrat Dam	Yes	Onsite Energy Moel: MTU Roil 3-DS30 Engine: John Deere 404HF 285 RPM:1800	Yes	Yes	?	Morris Fiddler	No						Ochikan Atawagamic: Store: No				
North Spirit Lake																	
Kasabonika																	
Kingfisher																	
Pikangikum																	

Community:	ator	Q4 - Describe what sorts of problems happen to community buildings during power outages, or happen from a lack of back-up power:	Q5- Tell the story of the worst power outage your community has experienced. What year, how long was the power out, anc how did your community deal with it?		
	Who Maintains?		Month & Year:	How Long was the Power Out?	How did your community deal with it?
Bearskin Lake		If it is winter and the power goes out, the furnace goes out, then the pipes freeze and sometimes break, water pipes, sewer pipes. If this happens then there is the worry of unsanitary conditions; Community Store - frozen items thaw out, cash registers don't work, debit machines not operational, lights out, no heating; Band office - administrative equipment ceases to work. Computers, phones, faxes, photo-copiers. No lighting. No heating; Water plant - back generator stands up, needs maintenance and upgrade; Garage(s) - power equipment ceases to work. No lights. No heating; Community Buildings - lights, heating; School - water system. Lights. Heating. School	June 2016	12 hours	Band office - not much work that day, no work; Restaurant - no work; School - no school; Residential homes - outside cooking over fire pits, propane stoves or wood stoves, Coleman stoves, use of candles and flashlights; everything shut down
Deer Lake		Power outage during winter. Most houses now have only heaters. Some have wood stoves to warm their homes. Internet/cable usually has to be reset. Every time theres power outage	June 2013	2 Days	Store had to let frozen stuff go. Had Sales on frozen foods. Band office was closed one day. Houses had candles lit during nights. School was out for summer. People cooked over fires outside
Keewaywin	Northern Managers	Keewaywin has experienced power outages in the past, most recently during our last workshop; People without woodstoves find it hard to cook and to heat up water (cooking and washing). They also don't have heat for their homes; Some people go a bit crazy without the internet (haha!)	During the winter (2-3 days) a few years		It was in the dead of winter. The generator blew out! No heat for anyone. Everyone was depended on furnaces and heaters; As for me, I had to dig out my woodstove. It was buried under the snow, maybe 3 feet of snow; It was so hard to cook. People had to cook outside; The store remained open during certain hours. Supplies ran out. The school was closed; The elders were cared for.
KI		Dialysis machine with backup power at the moment but will move to health centre; water plant does have backup power only at west end and not main land; community shuts down stores, and schools close			Usually when power goes out for a long period of time most stores close due to no lights and can't do anything when it comes to rushing out. As for school, they close for the day. And other building such as old folks building from my knowledge they ride or go to their family homes during the winter months. Some residents pull out the Coleman stoves. During winter and summer months they'll have cookouts outside
North Caribou Lake		Office equipment (computer, printer) got cold and some froze for an extended amount of time; freezer and refridgerator lose their efficiency; One dialysis patient in community and unable to do their procedure on schedule. Very important	December 2013/January 2014	4-5 weeks	The community had rolling blackouts. One part of the community would receive power for a few hours while the rest of the community does not. School had extended holidays. Christmas did not feel like Christmas. Old people spoke of old days. Most people got plenty of rest as homes would be without power
Poplar Hill	Daniel Moose	No internet/cell service; no water/sewage on houses with water/sewage tanks; no heating/cooling; store closed; school closed; water pipes freeze during winter when power goes out; frozen food/meat spoil and melt when power is out too long; gas station closed	December 2004	Several days	The power went out at the worst time during the coldest days of December. The houses with no wood stove had to move to relatives with wood stoves. The school and store were closed and band office was still open but no power. The teachers went out of town til goes back on and Northern Store managers went as well. Many people had to wait it out, stay warm near wood stoves, water lines were frozen, the generators at the power plant were broken down, some people were unprepared for the power outage as they did not gather enough fire wood.
Sachigo Lake		Power outages are not as frequent as they were when power was first introduced to the community. Usually nowadays, it is down for half days at a time (about 4-5 hours) when necessary, such as when Hydro One does major repairs or connects new buildings. But still, there is an inconvenience to power outages. The store will close, the business centres close, even with back generator at the community clinic, services are limited. Food will spoil, etc			
Sandy Lake	The workers usually check every couple weeks. It depends on		Winter either 1996 or 1997	Approximately 3 days	the longest power outage to happen in Sandy Lake that affected the entire community was when one of the mair lines was cut. In the area known as "airport" construction for a house was underway. During the digging for the foundation, one of the main power lines were cut. This line happened to be one that services the whole community. The same one from Hydro 1 came in to fix it. There are several recounts of this incident happening in the winter, lasting approximately three days. When Hydro 1 flew in to fix it, they were able to but about a day lat
Wapekeka		For clinic if there was a emergency during the power outage, medical equipment can't be used; Homes without woodstoves, only using furnaces heated by water - hotel, senior complex, duplexes; Store - freezers and coolers, meat and milk products tend to spoil when power outage is for days; during winter is not a good time for a power outage because cold weather months, some homes only use furnaces and heated by water	Unknown	12 hours mostly	None of the community facilities has backup power installed. Like for instance, school, band office, store, memorial, community gym, radio station, band garage, churches; Only some people has Coleman stoves for cooking and boiling or propane stove or heaters, not everyone has these for emergency backups; but during summer its not that bad, can just go outside and make fire and have a cookout; that's why its so important for the band to have a backup plan, mostly for the sick and elderly
Wawakapewin		All communications other than battery operated satellite phones go out. All electric heating goes. Water pipes freeze and burst. Had to throw out food. Don't trust freezers after leaving too long. Canned foods rendered bad	Aug-12	A week	Had to throw out all spoiled foods. Luckily happened in summer and we cooked outside. No communications. No AC. There was an outage that required the town to be evacuated
Wunnumin Lake		Power outages happen on a regular basis, on average about 3 times a month. The length of the power outage is varies from a few minutes to one hour. There have only been a few occasions when the power was out due to shortage of fuel. But that rarely happens. Something when the power goes out in a few minutes apart. Some of the electronics break like tv's and so on. For those that use a furnace in their places is uncomfortable especially in the winter times because it their homes	The worst experience we've had in our community is about 8 years ago. I have asked around what year that was but no one seems to remember	Even though the power went out for about 5 days but it was the worst the community had to	It was during the deep freeze when the power went down. The community was using the back up generator and that broke down. The power plant has three generators and the 1000 kilowatt and 600 kilowatt generators were both out of commission at that time. The back up back up generator is a 400-kilowatt and that was the community was using that time. The community had been limiting how much power we were using. It was a dai Christmas without Christmas lights that winter. Finally that final generator broke down too
Muskrat Dam		Communications: During a power outage, communications go down within the community, whether it's the internet, land lines or even cell service. The only place that would have backup power is the nursing station. Service: When there is a power outage the store services slow down due to a lack of power. No gas services.			
North Spirit Lake					
Kasabonika					
Kingfisher					
Pikangikum					

Appendix D: Outage Evaluation Matrix

	115 kV HV Line (km)	Unit	0- Unknown	1- Scheduled Outage	2- Loss of Supply	3- Tree Contacts	4- Lightning	5- Defective Equipment	6- Adverse Weather	7- Adverse Environment	8- Human Element	9- Foreign Interference	**TOTAL (Hr/Yr)**	**TOTAL (% of year)**
Pikanjikum (115 kV)	114	Qty (115 kV)	1.00	1.00	3.00	0.50	1.00	0.33	1.00	0.10	1.00	0.10		
		Duration	1.00	8.00	12.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	36.00	4.00	0.50	4.00	6.00	4.00	1.00	1.00		
		Sub-Total:	**1.00**	**8.00**	**36.00**	**4.00**	**0.50**	**4.00**	**6.00**	**4.00**	**1.00**	**1.00**	**65.50**	**0.75%**
Poplar Hill (115 kV)	189	Qty (115 kV)	1.00	1.00	3.00	1.00	2.00	0.33	2.00	0.20	1.00	0.20		
		Duration	1.00	8.00	12.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	36.00	8.00	1.00	4.00	12.00	8.00	1.00	2.00		
		Sub-Total:	**1.00**	**8.00**	**36.00**	**8.00**	**1.00**	**4.00**	**12.00**	**8.00**	**1.00**	**2.00**	**81.00**	**0.92%**
Deer Lake (115 kV)	243	Qty (115 kV)	1.00	1.00	3.00	1.25	2.50	0.33	2.50	0.25	1.00	0.25		
		Duration	1.00	8.00	12.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	36.00	10.00	1.25	4.00	15.00	10.00	1.00	2.50		
		Sub-Total:	**1.00**	**8.00**	**36.00**	**10.00**	**1.25**	**4.00**	**15.00**	**10.00**	**1.00**	**2.50**	**88.75**	**1.01%**
North Spirit Lake (115 kV)	282	Qty (115 kV)	1.00	1.00	3.00	1.50	3.00	0.33	3.00	0.30	1.00	0.30		
		Duration	1.00	8.00	12.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	36.00	12.00	1.50	4.00	18.00	12.00	1.00	3.00		
		Sub-Total:	**1.00**	**8.00**	**36.00**	**12.00**	**1.50**	**4.00**	**18.00**	**12.00**	**1.00**	**3.00**	**96.50**	**1.10%**
Sandy Lake (115 kV)	346	Qty (115 kV)	1.00	1.00	3.00	1.75	3.50	0.33	3.50	0.35	1.00	0.35		
		Duration	1.00	8.00	12.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	36.00	14.00	1.75	4.00	21.00	14.00	1.00	3.50		
		Sub-Total:	**1.00**	**8.00**	**36.00**	**14.00**	**1.75**	**4.00**	**21.00**	**14.00**	**1.00**	**3.50**	**104.25**	**1.19%**
Kee-way-win and Koocheching (115 kV)	361	Qty (115 kV)	1.00	1.00	3.00	1.75	3.50	0.33	3.50	0.35	1.00	0.35		
		Duration	1.00	8.00	12.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	36.00	14.00	1.75	4.00	21.00	14.00	1.00	3.50		
		Sub-Total:	**1.00**	**8.00**	**36.00**	**14.00**	**1.75**	**4.00**	**21.00**	**14.00**	**1.00**	**3.50**	**104.25**	**1.19%**

	115 kV HV Line (km)	Unit	0- Unknown	1- Scheduled Outage	2- Loss of Supply	3- Tree Contacts	4- Lightning	5- Defective Equipment	6- Adverse Weather	7- Adverse Environment	8- Human Element	9- Foreign Interference	**TOTAL (Hr/Yr)**	**TOTAL (% of year)**
Weagamow (North Caribou Lake)	277	Qty (115 kV)	1.00	1.00	2.00	1.50	3.00	0.33	3.00	0.30	1.00	0.30		
		Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	12.00	1.50	4.00	18.00	12.00	1.00	3.00		
(230 kV + 115 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Sub-Total:	**2.00**	**16.00**	**20.00**	**12.00**	**3.00**	**8.00**	**27.00**	**16.00**	**2.00**	**4.00**	**110.00**	**1.26%**
Muskrat Dam	364	Qty (115 kV)	1.00	1.00	2.00	1.75	3.50	0.33	3.50	0.35	1.00	0.35		
		Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	14.00	1.75	4.00	21.00	14.00	1.00	3.50		
(230 kV + 115 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Sub-Total:	**2.00**	**16.00**	**20.00**	**14.00**	**3.25**	**8.00**	**30.00**	**18.00**	**2.00**	**4.50**	**117.75**	**1.34%**
Bearskin Lake	436	Qty (115 kV)	1.00	1.00	2.00	2.25	4.50	0.33	4.50	0.45	1.00	0.45		
		Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	18.00	2.25	4.00	27.00	18.00	1.00	4.50		
(230 kV + 115 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Sub-Total:	**2.00**	**16.00**	**20.00**	**18.00**	**3.75**	**8.00**	**36.00**	**22.00**	**2.00**	**5.50**	**133.25**	**1.52%**
Sachigo Lake	456	Qty (115 kV)	1.00	1.00	2.00	2.25	4.50	0.33	4.50	0.45	1.00	0.45		
		Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	18.00	2.25	4.00	27.00	18.00	1.00	4.50		
(230 kV + 115 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Sub-Total:	**2.00**	**16.00**	**20.00**	**18.00**	**3.75**	**8.00**	**36.00**	**22.00**	**2.00**	**5.50**	**133.25**	**1.52%**
Kingfisher Lake	245	Qty (115 kV)	1.00	1.00	2.00	1.25	2.50	0.33	2.50	0.25	1.00	0.25		
		Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	10.00	1.25	4.00	15.00	10.00	1.00	2.50		
(230 kV + 115 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Sub-Total:	**2.00**	**16.00**	**20.00**	**10.00**	**2.75**	**8.00**	**24.00**	**14.00**	**2.00**	**3.50**	**102.25**	**1.17%**
Wunnumin Lake	245	Qty (115 kV)	1.00	1.00	2.00	1.25	2.50	0.33	2.50	0.25	1.00	0.25		
		Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	10.00	1.25	4.00	15.00	10.00	1.00	2.50		
(230 kV + 115 kV + 44 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Hr/Yr (44 kV)	1.00	8.00	0.00	4.00	0.50	4.00	3.00	4.00	1.00	1.00		
		Sub-Total:	**3.00**	**24.00**	**20.00**	**14.00**	**3.25**	**12.00**	**27.00**	**18.00**	**3.00**	**4.50**	**128.75**	**1.47%**

	115 kV HV Line (km)	Unit	0- Unknown	1- Scheduled Outage	2- Loss of Supply	3- Tree Contacts	4- Lightning	5- Defective Equipment	6- Adverse Weather	7- Adverse Environment	8- Human Element	9- Foreign Interference	**TOTAL (Hr/Yr)**	**TOTAL (% of year)**
		Qty (115 kV)	1.00	1.00	2.00	1.75	3.50	0.33	3.50	0.35	1.00	0.35		
Wawakepewin	336	Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	14.00	1.75	4.00	21.00	14.00	1.00	3.50		
(230 kV + 115 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Sub-Total:	**2.00**	**16.00**	**20.00**	**14.00**	**3.25**	**8.00**	**30.00**	**18.00**	**2.00**	**4.50**	**117.75**	**1.34%**
		Qty (115 kV)	1.00	1.00	2.00	1.75	3.50	0.33	3.50	0.35	1.00	0.35		
Kasabonika Lake	336	Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	14.00	1.75	4.00	21.00	14.00	1.00	3.50		
(230 kV + 115 kV + 44 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Hr/Yr (44 kV)	1.00	8.00	0.00	4.00	0.50	4.00	3.00	4.00	1.00	1.00		
		Sub-Total:	**3.00**	**24.00**	**20.00**	**18.00**	**3.75**	**12.00**	**33.00**	**22.00**	**3.00**	**5.50**	**144.25**	**1.65%**
		Qty (115 kV)	1.00	1.00	2.00	2.00	4.00	0.33	4.00	0.40	1.00	0.40		
Wapekeka	400	Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
		Hr/Yr (115 kV)	1.00	8.00	20.00	16.00	2.00	4.00	24.00	16.00	1.00	4.00		
(230 kV + 115 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Sub-Total:	**2.00**	**16.00**	**20.00**	**16.00**	**3.50**	**8.00**	**33.00**	**20.00**	**2.00**	**5.00**	**125.50**	**1.43%**
		Qty (115 kV)	1.00	1.00	2.00	2.00	4.00	0.33	4.00	0.40	1.00	0.40		
Kitchenuhmaykoosib Inninuwug	400	Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
(Big Trout Lake)		Hr/Yr (115 kV)	1.00	8.00	20.00	16.00	2.00	4.00	24.00	16.00	1.00	4.00		
(230 kV + 115 kV)		Hr/Yr (230 kV)	1.00	8.00	0.00	0.00	1.50	4.00	9.00	4.00	1.00	1.00		
		Sub-Total:	**2.00**	**16.00**	**20.00**	**16.00**	**3.50**	**8.00**	**33.00**	**20.00**	**2.00**	**5.00**	**125.50**	**1.43%**
		Qty (230 kV)	1.00	1.00	0.00	0.00	3.00	0.33	1.50	0.10	1.00	0.10		
230 kV Line - 300 km		Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
(Watay SS to Pickle Lake)		**Hr/Yr (230 kV)**	**1.00**	**8.00**	**0.00**	**0.00**	**1.50**	**4.00**	**9.00**	**4.00**	**1.00**	**1.00**	**29.50**	
		Qty (44 kV)	1.00	1.00	0.00	0.50	1.00	0.33	0.50	0.10	1.00	0.10		
44 kV Line - 50 km		Duration	1.00	8.00	10.00	8.00	0.50	12.00	6.00	40.00	1.00	10.00		
(Wunnumin Lake & Kasabonika Lake)		**Hr/Yr (44 kV)**	**1.00**	**8.00**	**0.00**	**4.00**	**0.50**	**4.00**	**3.00**	**4.00**	**1.00**	**1.00**	**26.50**	

CAUSE OF INTERRUPTIONS	QTY/HR
<u>0- Unknown</u> No apparent cause that contributed to the outage	1 per year per community fed by a section of the 115 kV transmission line + 1 per 230 kV + 1 per 44 kV (when applicable) 1h per outage
<u>1- Scheduled outage</u> Disconnection at a selected time for the purpose of construction or preventive maintenance	1 per year per community fed by a section of the 115 kV transmission line + 1 per 230 kV + 1 per 44 kV (when applicable) 8h per outage
<u>2- Loss of Supply</u> Problems associated with assets owned and/or operated by another party (utility)	3 per year (Red Lake Subsystem) 12h per outage (Red Lake Subsystem) 2 per year (Pickle Lake Subsystem) 10h per outage (Pickle Lake Subsystem)
<u>3- Tree contacts</u> Faults resulting from tree contact with energized circuits	0.5 per year / 100 km HV Line (115 kV & 44 kV only) 8h per outage
<u>4- Lightning</u> Lightning failure involving the three phases, resulting in an insulation breakdown and/or flash-overs	1 per year / 100 km HV Line 0.5h per outage
<u>5- Defective Equipment</u> Equipment failures due to improper installation, deterioration from age, incorrect maintenance, or imminent failures detected by maintenance	0.33 per year per community fed by a section of the 115 kV transmission line + 1 per 230 kV + 1 per 44 kV (when applicable) 12h per outage
<u>6- Adverse Weather</u> Rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions	1 per year / 100 km HV Line (115 kV & 44 kV) 0.5 per year / 100 km HV Line (230 kV) 6h per outage
<u>7- Adverse Environment</u> Equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire.	0.1 per year / 100 km HV Line 40h per outage
<u>8- Human Element</u> Interface of staff with the system	1 per year per community fed by a section of the 115 kV transmission line + 1 per 230 kV + 1 per 44 kV (when applicable) 1h per outage
<u>9- Foreign Interference</u> Beyond the control of the utility, such as those caused by animals, vehicules, dig-ins, vandalism, sabotage and foreign objects	0.1 per year / 100 km HV Line 10h per outage

Appendix E: Net Present Cost (NPC) Table

Net Present Cost (NPC) Evaluation

Community Name	Emergency generator Capital Cost for critical infrastructure	Scenarios				Year First Investment in Community's DGS		Year Existing DGS Retired - critical infrast. back up only (Scenario 3)
		1	2	3	4	To meet 100% of load demand (Scenario 1)	To meet 50% of load demand (Scenario 2)	
	M$2021							
Deer Lake	0.47 $	$42	$15	$2.1	$1.6	2024	2042	2028
Kee-way-win and Koocheching	0.94 $	$31	$16	$2.0	$1.9	2021	2021	2029
North Spirit Lake	1.88 $	$26	$14	$2.3	$1.7	2021	2021	2043
Pikangikum	- $	$83	$43	$1.5	$0.6	2021	2021	2029
Poplar Hill	0.47 $	$33	$17	$2.0	$1.4	2021	2021	2038
Sandy Lake	0.94 $	$82	$26	$4.8	$2.2	2028	2046	2032
Bearskin Lake	1.41 $	$19	$5	$3.3	$2.8	2036	2053	2040
Kasabonica Lake	- $	$43	$18	$1.3	$1.3	2021	2029	2021
Kingfisher Lake	- $	$22	$8	$1.5	$0.9	2028	2046	2032
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	0.94 $	$31	$16	$3.0	$2.5	2030	2048	2034
Muskrat Dam	1.88 $	$31	$16	$3.0	$2.5	2021	2021	2040
Sachigo Lake	1.41 $	$18	$4	$3.9	$2.8	2040	2058	2044
Wapekeka	0.94 $	$22	$7	$2.9	$2.6	2028	2046	2033
Wawakepewin	0.94 $	$8	$5	$1.2	$1.4	2021	2021	2036
Weagamow (North Caribou Lake)	1.88 $	$41	$16	$2.3	$2.3	2021	2033	2021
Wunnumin Lake	0.94 $	$43	$22	$3.6	$2.7	2021	2021	2036
TOTAL	**15.0 $**	**575.4 $**	**248.2 $**	**40.7 $**	**31.2 $**			

BBA