TECHNICAL REPORT FOR THE CONNECTION OF REMOTE FIRST NATION COMMUNITIES IN NORTHWEST ONTARIO

FOR

NORTHWEST ONTARIO FIRST NATION TRANSMISSION PLANNING COMMITTEE

Contents

1.0 EXECUTIVE SUMMARY OF OPA'S TECHNICAL REPORT ON REMOTE COMMUNITY CONNECTION

This document summarizes the Ontario Power Authority's ("OPA") technical report to the Northwest Ontario First Nation Transmission Planning Committee (the "Committee"). The OPA's technical report provides a baseline of options for the remote community connection plan being developed by the Committee. The plan is intended to establish, at a planning level of certainty, the technical and economic viability of connecting remote First Nations communities to the provincial electricity grid.

There are 25 remote First Nations communities in northwestern Ontario. These communities are considered remote because they are not connected to the provincial electricity grid and because most do not have all-season road access. Electricity service within these communities is supplied by local diesel generators. Figure 1 shows the location of the northwest Ontario remote communities.

Diesel generation is in general the highest cost electricity generation resource currently supplying Ontario customers, typically costing 3 to 10 times more than the average cost of the provincial supply mix.

Figure 1: Northwest Ontario Remote Communities

Source: OPA[1]

<u>Existing Funding Structure</u>

The parties who currently fund the electricity systems in these communities are, most notably, the federal government (Aboriginal Affairs and Northern Development Canada - AANDC), Ontario electricity customers (through Rural and Remote Rate Protection - RRRP) and the provincial government (through the payment of Standard-A Electricity Rates for provincial facilities located within the Remote Communities). The remaining revenue is paid by community members who are regular retail and commercial customers

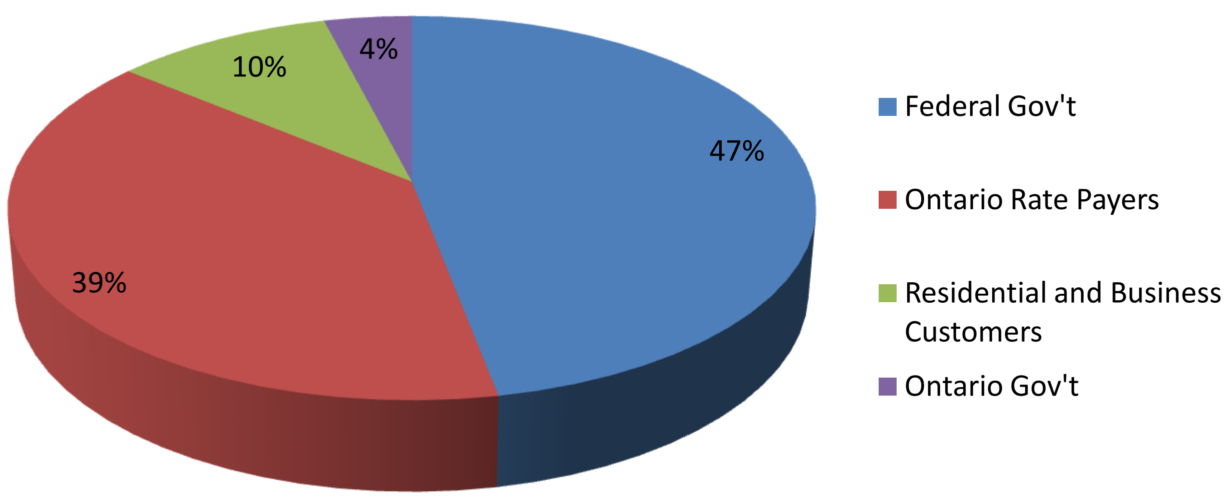
[1] Note: Whitesand First Nation and the Town of Collins are connected to the generating station at Armstrong

(non-standard A customers) and who pay rates similar to other Ontario rate payers. The estimated current allocation of the expense by funding party is illustrated in Figure 2.

Substantial near term investment will be required in order to realize the long term benefits of reduced diesel use in remote communities. In order to implement the project, the remote community funding parties as well as any industrial customers who wish to make use of the transmission assets will need to come to agreement on the allocation of project costs among them.

Figure 2: Estimated Current Share of Annual Cost of Diesel Generation in the 25 Remote Communities by funding source

Current Total Cost is estimated to be about $68 Million per year



Source: OPA[2]

Economic Analysis

The OPA has developed a detailed economic analysis comparing the avoidable cost[3] of continued diesel generation with the cost of transmission connection and supplying

[2] Note: IPA costs were estimated based on the assumption that they are equal to HORCI costs per MWh of consumption using values reported in HORCI's 2009 Cost of Service Application

electricity to remote First Nations communities from the provincial generation fleet. This analysis indicates that there is a strong economic case at this time for connecting 20 of the 25 remote First Nations communities in northwest Ontario to the provincial electricity grid. Analysis indicates that there are also opportunities for sharing transmission facilities between industrial customers and these remote communities.

Assumptions

For the purpose of this plan, the following key assumptions underlie the OPA's analysis:

- The nature of the power system remains the same as when the report was written
- An outlook or study period of 40 years (2013 to 2053);
- An average long-term inflation rate of 2%;
- Community annual electricity demand growth of 4% after 2015;
- Initially 50% of fuel will be delivered by winter road and 50% by air. Over the next 20 years the road delivered portion is assumed to decline to 40%;
- The OPA Ontario electricity price forecast (which is based on current energy sector plans and policies until 2031);
- A social discount rate of 4%, consistent with social-based analysis of this nature routinely conducted by the OPA.

Avoidable Diesel Costs

To compare the cost of continued diesel generation with the cost of transmission connection for the group of 20 communities, the OPA forecasted the diesel generation costs that could be avoided after the 20 communities are connected to the provincial transmission system. Communities are assumed to begin connecting to the provincial electricity grid after 2016, at which time the savings in avoided diesel generation could begin.

3 Avoidable costs of diesel operation are the generation related costs (fuel, variable operations and maintenance, variable overhead, etc.) that can reasonably be expected to be eliminated when an alternate supply source, such as a transmission connection, is used to supply electricity in remote communities.

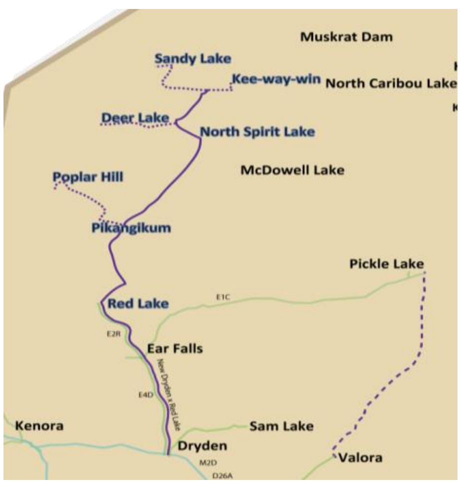
Transmission Supply Options

The OPA found that radial transmission configurations from Red Lake and Pickle Lake can best connect these communities, by providing the best overall balance of cost, operability and reliability[4]. The six communities north of Red Lake can be served by a single radial 115 kV line from Red Lake and the 14 communities north and east of Pickle Lake can be served by several 115 kV lines from Pickle Lake.

Red Lake Cluster

The supply option from Red Lake is designed to serve the six communities north of Red Lake with a new 115 kV single-circuit line. This new 115 kV line would extend the existing transmission system at Red Lake Transmission Station (TS) north toward Pikangikum First Nation, then to North Spirit Lake First Nation, terminating at a new TS south east of Sandy Lake First Nation. Figure 3 shows this connection concept.

Figure 3: Red Lake Cluster Connection Concept



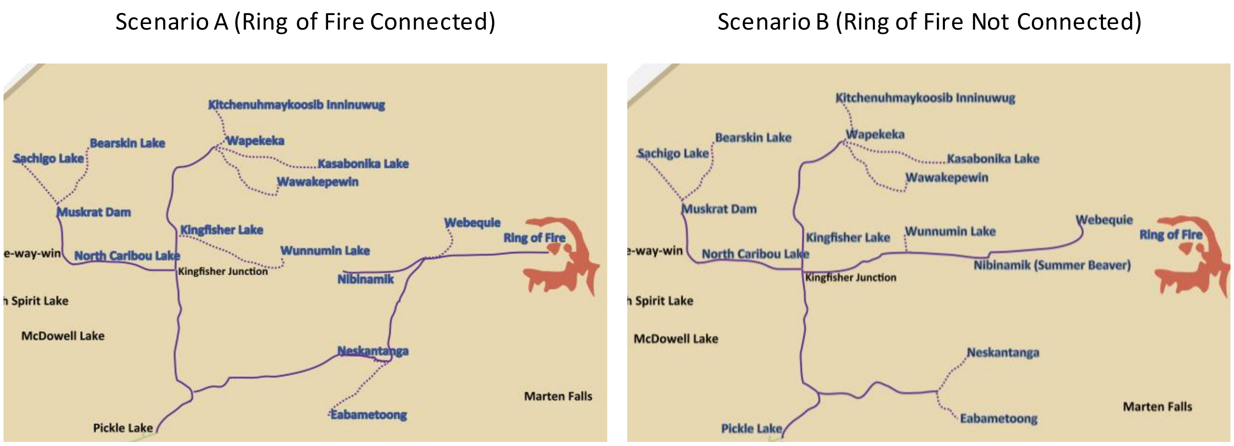
Source: OPA

Pickle Lake Cluster

[4] A radial transmission system is one where one or more customers (generators or load) are connected to a single point on an electricity system, which differs from a network system where there are multiple connection points.

Two potential configurations have been identified (shown in Figure 4) for the cluster of 14 communities north and east of Pickle Lake based on whether or not a new line from Pickle Lake will be built to supply potential mining developments at the Ring of Fire.

Figure 4: Pickle Lake Cluster Connection Concepts



Source: OPA

Scenario A, includes supplying all 14 remote communities north and east of Pickle Lake and the Ring of Fire from Pickle Lake. Scenario B includes only the 14 communities north and east of Pickle Lake and excludes connection at the Ring of Fire, which leads to a different connection configuration for the communities. This connection configuration is designed to minimize the cost for this scenario. With the connection of mines at the Ring of Fire, serving forecast load growth in Scenario A will require 230 kV supply at Pickle Lake. Therefore the new line to supply Pickle Lake in this scenario will be 230 kV. The load forecast for the Pickle Lake area in Scenario B indicates that it can be adequately served by a new 115 kV line until about 2033 if 20 MW of load is transferred from Pickle Lake to Ear Falls via E1C after a new line is built from Dryden to Red Lake. However, pre-building the new line to Pickle Lake to 230 kV standards and operating it at 115 kV may be worthwhile as preserves the option for the line to be operated at 230 kV in the future to serve Pickle Lake area load instead of requiring load to be transferred to Ear Falls. This would provide incremental capacity at Ear Falls to serve load growth in the Red Lake area for the long term. Maintaining the option of upgrading Pickle Lake to 230 kV supply would also ensure that load growth in the Pickle Lake area beyond the 2033 or unforeseen load growth in the near or medium term (such as a new mine development requiring connection) can be served adequately without having to build an additional line.

Total capital costs for Scenario A are about $50 million higher than for Scenario B, however, the cost attributable to the remote connection plan for Scenario A is estimated to be about $150 million less than for Scenario B due to the potential for cost sharing with the industrial customers sharing the proposed new facilities.

For this assessment, costs were assumed to be attributed to each party in proportion to the relative magnitude of load each is assumed to connect to the system. This methodology is consistent with the Ontario Energy Board's Cost Allocation Principles as defined in the Transmission System Code.

The scenarios identified in this plan require new transmission voltage lines (230 kV and 115 kV), new distribution lines (44 kV and lower) as well as 230 kV and 115 kV transformer stations. Table 1 summarizes the line distances and the number of transformer stations required for each remote community cluster and scenario.

Table 1: Scope of Proposed Remote Community Transmission Connection Plan

	Transmission Line (Km)	Distribution Line (Km)	230/115 kV Transformer Stations	Low Voltage Transformer Stations
Red Lake Cluster	**260**	**240**	**0**	**3**
Pickle Lake Cluster Scenario A	**1,120**	**580**	**1**	**7**
Pickle Lake Cluster Scenario B	**1,130**	**470**	**0**	**8**

Connection Project Capital Cost

Based on the line distances and the number of required station facilities identified in Table 1, the OPA developed a forecast of project capital costs using unit costs developed by an experienced third party engineering consultant (cost forecast is summarized in Table 2). Scenario A is forecast to cost approximately $1.3 billion, of which about $900 million is attributable to the connection of remote communities, while the remainder is assumed to be covered by participating industrial customers. Scenario B is forecast to cost approximately $1.2 billion, of which about $1 billion is attributable to the remote community connection project.

Table 2: Total Project Capital Costs and Contributions from Other Parties Sharing Assets

	Scenario A with RoF ($M)			Scenario B no RoF ($M)		
	Remotes	Other Parties	Total	Remotes	Other Parties	Total
Remote Connection Only Facilities ($M)	710	0	710	945	0	945
Shared Transmission Facilities ($M)	175	395	570	95	190	285
Total Project Capital Cost	885	395	1280	1040	190	1230
Load Growth (MW)	33	100	133	33	65	98
Cost per MW Served ($M/MW)	27			32		

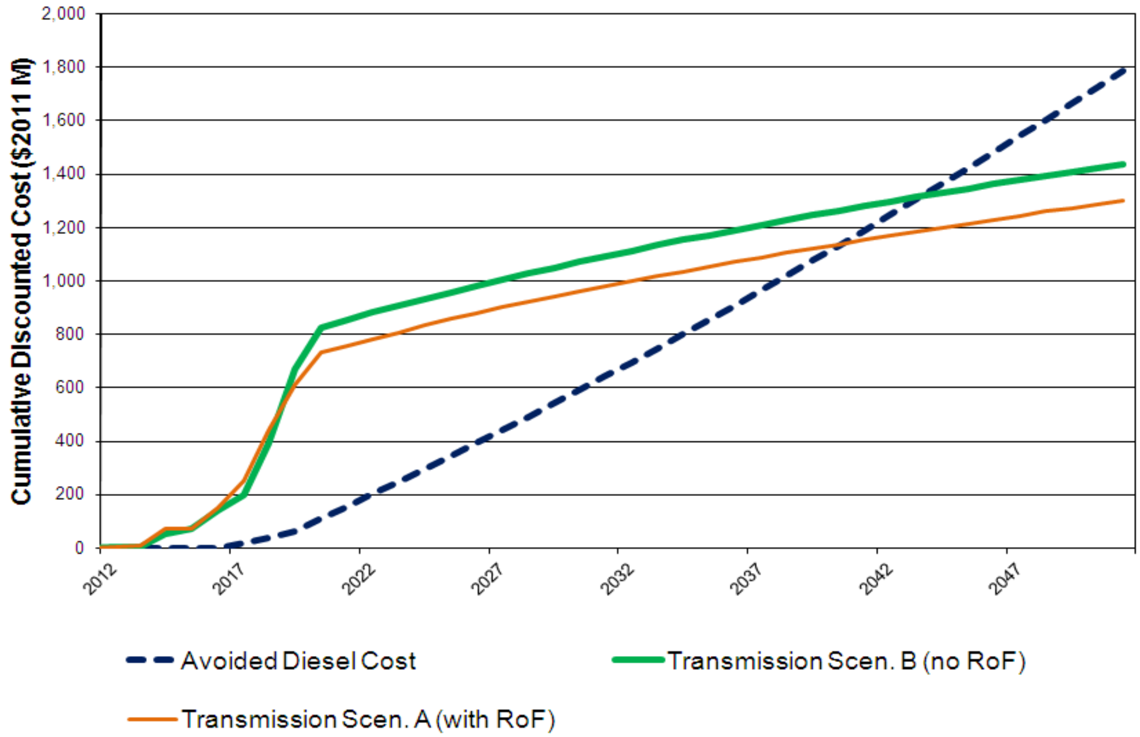
Source: OPA

Net Benefit

Based on the direct avoidable diesel costs assessed and the total cost of transmission connection, the combined connection project is expected to break-even 20-25 years after all of the communities are connected. The cost of connecting these communities is estimated to be 20% to 30% lower than the avoidable cost of continuing to power them with diesel generation until 2053. Figure 5 shows the cumulative costs of continued diesel supply, and the transmission connection scenarios.

A payback period of this duration (20-25 years) is reasonable for electricity infrastructure assets that are expected to last at least 50 years before requiring substantial reinvestment or refurbishment. In this area, transmission assets can last in excess of 80 years with proper operations and maintenance.

Figure 5: Cumulative Cost of Transmission Connection Vs. Cumulative Avoidable Cost of Diesel Generation



Source: OPA

The business case for transmission connection developed by the OPA is based solely upon direct avoided diesel costs and does not reflect the additional economic, social, developmental and environmental benefits that would also arise with transmission connection of remote First Nation communities, including: reduced infrastructure barriers to growth, increased economic development opportunities (both within the remote communities as well as regionally), improved social and living conditions for remote community residents, cleaner air and reduced greenhouse gas emissions, reduced future environmental remediation liabilities associated with diesel fuel spills, and improved reliability of electricity supply.

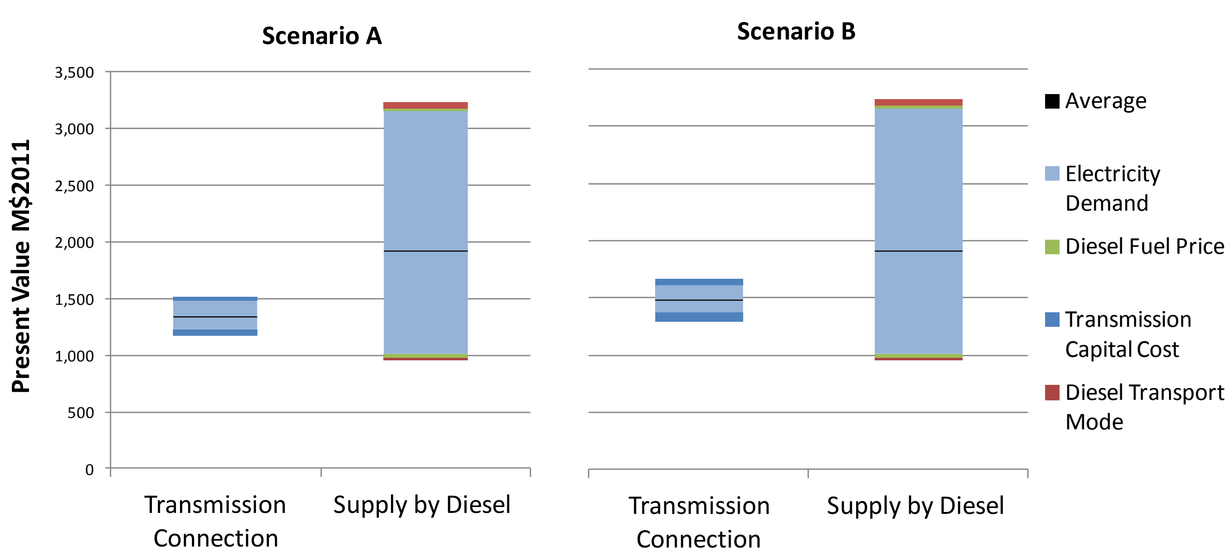
Uncertainty Analysis

To determine the degree to which the findings within this analysis are robust, the OPA conducted an uncertainty analysis. This analysis provides a statistical representation of the net present value of the business case over a wide range of assumptions for several key variables which were found to be the primary drivers for determining the outcomes. To conduct this analysis the OPA used a standard uncertainty analysis methodology (Monte Carlo Simulation) which is commonly used in business case analysis when there is uncertainty in the input assumptions of a model.

The range of costs for each transmission scenario is compared with the diesel case in Figure 6 below.

These findings indicate that under a wide range of probable input assumptions, both scenarios (A and B) are expected to cost less than diesel in about 75% of the scenarios tested. This finding is a strong indicator that net economic benefits will materialize before 2053 if transmission connection is pursued.

Figure 6: Distribution of Cost of Transmission Connection Vs. Avoidable Cost of Diesel Generation



Source: OPA

Integrated Renewables with Diesel Generation

A third strategic supply option that was evaluated for supplying remote communities was the utilization of the existing diesel generators in the communities integrated with local renewable resources, and battery storage, to minimize the use of diesel. In all cases diesel generation would still be needed to meet demand when variable renewable resources are insufficient or unavailable, such as when run of river hydro sites have insufficient flow to meet demand or wind is not available. Therefore continued investment in diesel capacity will be required to match load growth in each community.

The OPA has found it unlikely that all communities could be served economically by renewable generation integrated with diesel. However, in communities that are not currently economic to connect, renewable generation can economically reduce diesel consumption, improving local electricity supply and reducing the economic and environmental costs of diesel generation. Table 3 shows a cost comparison of the renewable supply options with diesel generation and transmission connection.

Table 3: Comparative Average Total Cost of Electricity Supply For Alternative Supply Technologies

	Average Total Cost of Supply to 2051 ($/kWh)		
	Low	High	Remaining on Diesel Supply
Diesel Generation	0.83	0.87	All
Isolated Wind Integrated with Diesel	0.59	0.63	All
Hydro Connected to Community Clusters	0.43	0.48	>10
Transmission Connection	0.39	0.43	5

Source: OPA

Conclusion and Summary

Transmission connection of Ontario's remote northwestern First Nation communities would avoid the loss of $430M to $580M in diesel costs that will otherwise be spent over the 40 year study period, while providing a cleaner and more reliable electricity supply, which in turn reduces environmental risks. Transmission connection will also improve the living conditions within the communities by removing barriers to community development. This includes enabling increases to the housing stock, expansion of community services and the development / expansion of local businesses. These factors are critical to capturing business opportunities as the mining sector expands in this area.

The financial benefits of connecting remote communities will accrue to the parties who currently fund their electricity systems, most notably the Federal Government and Ontario electricity customers. Discussions toward a funding agreement may find a starting point in the notion that costs ought to be borne proportionally to use. Extensive and early engagement among the negotiating parties will be essential to achieve a firm agreement on cost sharing and allocation that will enable this project to be realized.

2.0 INTRODUCTION AND BACKGROUND

This document describes the Ontario Power Authority's ("OPA") technical recommendations to the Northwest Ontario First Nation Transmission Planning Committee (the "Committee") regarding its development of a plan to connect remote First Nation communities in northwest Ontario. The Committee is a collaborative effort between representatives of affected First Nation Communities in northwest Ontario, and the OPA. The purpose of the Committee as stated in its Terms of Reference is as follows:

> …to develop a regulatory business case for the expansion of the Ontario electrical transmission system to the remote north. In developing the regulatory business case the Committee, by conferring with the communities, will undertake to capture the diverse needs of the communities and reflect those needs within the technical options for connecting to the provincial transmission system.

The OPA has developed this technical report to serve as a baseline of technical options for the remote community connection plan being developed by the Committee. This report is intended to establish at a planning level of certainty the technical and economic viability of connecting remote First Nation communities to the Independent Electricity System Operator ("IESO") controlled grid. In developing this report, the OPA has sought input from First Nation Committee members, who have contributed their technical and traditional local knowledge as well as the interests of their communities, while the OPA has provided expertise in power system planning. To ensure the transmission plan includes facilities required to effectively operate and maintain the system, the OPA also engaged the services of the IESO to conduct an operational feasibility study of the connection plan. The results of this study have been factored into the connection plan.

Members of represented communities have also served as community based researchers helping the Committee to assess the capabilities and condition of the electrical power systems in their communities and communicate the work of the Committee to interested parties within their communities. These contributions have been integrated into the analysis and the assessment of options that forms the basis of this technical report.

The technical report is supported by a detailed economic analysis which compares the avoidable cost[5] of continued diesel generation with the cost of transmission connection and supplying electricity to remote First Nation communities in northwest Ontario with the Provincial generation fleet. This analysis indicates that there is a strong economic case at this time for connecting at least 20 of the 25 remote First Nation communities in northwest Ontario to the IESO controlled grid. The cost of connecting these communities has been assessed to be 20% to 30% lower than the avoidable cost of continuing to power them with diesel generation between 2017 and 2053. Cost savings for benefitting parties are expected to begin to be realized within the first few years of connection, while project break even is expected within 20-25 years of project completion. The 20-25 year break even period represents less than half the average expected life of transmission and distribution assets such as those proposed to be installed and is therefore considered reasonable for such long lived assets.

It is important to recognize that the OPA's business case for transmission connection is based solely upon direct avoided diesel costs and does not reflect the additional economic, social, developmental and environmental benefits that would also arise with transmission connection of remote First Nation communities, including but not limited to: reduced infrastructure barriers to growth which may lead tonew economic development opportunities (both within the remote communities as well as regionally), improved social and living conditions for remote community residents, cleaner air and reduced greenhouse gas emissions, reduced future environmental remediation liabilities associated with diesel fuel spills, and improved reliability of electricity supply.

For the foreseeable future, expansion of the mining sector is expected to be a major economic driver of the northwest Ontario economy. Some of the remote First Nations may have the opportunity to participate in the economic activity created by mine development activity. Economic access to electricity in close proximity to a potential mine development is an important consideration for mine project developers in making the decision to invest in

5 Avoidable costs of diesel operation are the generation related costs, (fuel, variable operations and maintenance, variable overhead, etc.) that can reasonably be expected to be eliminated when an alternate supply source, such as a transmission connection, is used to supply electricity in remote communities.

a specific property. Therefore it is expected that once a transmission system connecting the remote communities is available, it may enhance the value of some properties in those areas and lead to new mines being developed. Connection of these new mining loads would be incremental to the load forecast for the area. In return for providing connection to such industrial loads there is expected to be a requirement for capital contributions from these customers, depending on timing as outlined in Sections 6.3 and 6.5 of the Transmission System Code. Opportunities of this nature could help to reduce the costs for the funding partners of the transmission connection projects outlined in this report.

It should be noted the results of the analysis included in this technical report are based on assumptions regarding the nature of the power system when the report was written. Should the nature of the load, generation or transmission system in northwest Ontario change materially it may have an impact on the feasibility and costs of the options identified in this report.

The benefits of connecting remote communities to the provincial transmission grid will accrue to the parties who currently fund their electricity systems, most notably the federal government, Ontario electricity customers and the provincial government. However, substantial near term investment will be required in order to realize the long term benefits of reduced diesel use in remote communities. In order to implement the project, the remote community funding parties as well as any industrial customers who wish to make use of the transmission assets will need to come to agreement on the allocation of project costs among them. A core principle of cost sharing is that costs ought to be borne proportionally to expected benefits. Early engagement among funding parties will be essential to achieve a firm agreement on cost sharing.

It is also important to note that, the Far North Act, being implemented by Ontario Ministry of Natural Resources, requires that all communities conduct land use planning prior to commencing the development of new transmission facilities; thus, the development timelines identified in this remote community connection plan may be affected by the progress the communities make in completing their land use plans.

2.1 Background on Energy Supply in Remote First Nations Communities in Northwestern Ontario

There are 32 remote communities in Ontario with electricity generation and distribution systems that are not connected to the provincial transmission grid.[6] Of these, 25 are recognized First Nation reservation communities in northwest Ontario with a combined on reserve population of approximately 15,000 people, and peak electricity demand of less than 20 MW. Both population and electricity demand have been growing faster than other regions of Ontario.

The communities are dispersed along an 800 km arc starting from about 90 km north of Red Lake to about 160 km east of Pickle Lake as shown in Figure 7. None of the communities north of Red Lake and Pickle Lake have access to all-season transportation or utility corridors. The average distance separating these communities is about 60 km, with distances ranging between 20 km and 90 km.

These communities are considered remote because most do not have all-season road access and/or they are not connected to the IESO controlled grid. Electricity service within these communities is supplied by local internal combustion diesel engines driving alternating current (AC) generators, which feed local distribution grids. To date integrated regional transportation, communication or energy networks have not been developed between most communities. The exceptions are the communities of Armstrong, Collins, and the Whitesand First Nation which are close in proximity and connected to a common diesel generating station located in Armstrong. Recently, development of a fiber optic network to service some of these communities began under a federal government initiative. A number of other communities are connected to one or a few other communities by roads.

6 The number of remote communities identified differs depending on the source of information. In some cases, neighboring communities are classified as a single community even though residents may self-identify as separate communities. Examples are Keewaywin and Koochiching, which tend to be shown as a single community on Hydro One maps, or the communities of Collins, Armstrong and the Whitesand First Nation. These communities and the First Nation are often shown as a single entity on maps.

Figure 7: Northwest Ontario Remote Communities

Source: OPA

Note: Whitesand First Nation and the Town of Collins are connected to the generating station at Armstrong.

For the majority, winter roads provide seasonal access for one to two months per year; air transport is the only means to and from the communities for the remainder of the year. This presents a significant challenge in transporting fuel for generation to the communities. Communities utilize local fuel storage (capacity is generally less than a full year) which is replenished when winter road access is available and by air the remainder of the year. Air transport is significantly more expensive that road transport and therefore has a significant impact on the delivered cost of fuel and the total cost of supplying electricity in communities that require air transport. As an example the warm winter of 2011/12 resulted in a much shorter winter road season than normal, which is expected to lead to a substantially greater proportion of fuel being transported by air for the remainder of 2012.

As mentioned above, the electricity systems in these communities are supplied by internal combustion diesel engines coupled to AC generators. In general these AC generators produce an output voltage of 600 volts, which is then stepped up to the operating voltage of the community distribution system (3.7 kV, 13.6 kV, 25 kV, or other).

Reliability is a critically important factor, particularly in cold weather months as electric heating is predominant in many communities and lighting is needed due to few daylight hours in the winter months. Based on this need for reliability, operational flexibility, and efficiency, installed generation capacity of about 235% of peak demand, is maintained within these communities. Typically 3 generation units are used and are sized in the ratio 5:3:2. The capacity of the two smallest units establishes the load serving capacity (prime rating) of the system. In comparison the normal generation reserve requirement for the IESO controlled grid is about 20% of peak demand.

To accommodate load growth, the diesel systems are typically expanded when peak load reaches 85% of the prime rated capacity of the system. When system expansion is not provided new load connections may be refused until new capacity is made available.

Diesel generation in remote communities is in general the highest cost electricity generation resource currently supplying Ontario customers, costing 3 to 10 times more than the average cost of the provincial supply mix. These high supply costs are due to a number of reasons including the high cost of diesel fuel, which is compounded by the need to transport (by winter road and air) and store the fuel in the communities, as well the higher operating and capital costs of performing construction and maintenance work in these remote locations.

Since 2000, a number of studies have been conducted to assess the viability of connecting remote communities to the provincial IESO controlled grid. In 2001, Indian and Northern Affairs Canada (now known as Aboriginal Affairs and Northern Development Canada ("AANDC")) completed a study of the connection viability of the remote First Nation communities in northwest Ontario. In 2009, the Ontario Waterpower Working Group commissioned a similar study of the options for connecting remote communities and high potential hydro resources in the region. Each of these studies concluded that transmission connection of the remote communities north of Red Lake and Pickle Lake is economically viable.

2.2 Current Allocation of Costs for Remote Community Electricity Supply

There are a number of parties involved in providing and funding electricity supply in remote First Nation communities. AANDC is the department within the Government of Canada responsible for providing and funding infrastructure in all on-reserve First Nation communities in Canada, including electricity supply systems. However, operational responsibilities for 15 First Nation remote communities were transferred to the former Ontario Hydro through electrification agreements. Responsibility for their operation now rests with a subsidiary of Hydro One called Hydro One Remote Communities Inc. ("H1RCI"). For the remote communities served by H1RCI, AANDC continues to be responsible for funding generation and distribution system expansion associated with load growth in the communities. H1RCI is responsible for operational costs, which include the cost of diesel fuel and maintenance. H1RCI is also responsible for the capital costs for asset replacement due to end of life and improvements that are not associated with load growth. Communities not served by H1RCI are served by First Nation owned Independent Power Authorities (IPAs), which are owned by and serve a single community. Among the 25 remote communities, 15 are supplied by H1RCI and 10 are supplied by their own IPAs that are not regulated by the Ontario Energy Board. AANDC remains fully responsible for maintaining funding of the electricity supply systems in the IPA served communities.

As a provincially regulated utility, H1RCI receives a subsidy known as Rural and Remote Rate Protection ("RRRP"), which is funded by all Ontario electricity customers. The RRRP subsidy is used to partially offset the higher cost of providing electricity to rural and remote areas. RRRP is charged to all Ontario electricity customers at the rate of $0.13/kWh. In 2009, $163 million was collected to offset rural and remote rates; in 2010 this amount grew to $181 million. IPA communities do not receive RRRP.

In 2009, H1RCI received approximately $28 million of the $163 million paid in RRRP charges by rate payers, to fund the 21 remote community electricity systems it serves (including 15 First Nation communities). The 6 non-First Nation remote communities include the Towns of Collins and Armstrong and a number of remote rail communities in northern Ontario. The balance of RRRP was used to subsidize the rates of other rural customers in Ontario.

Federally and provincially owned facilities, such as medical facilities, pay a rate known as the Standard A Rate, which notionally represents the full cost of electricity service to these facilities. The Standard A rate as well as the regular retail and commercial rates for H1RCI served communities are set by the OEB through its rate setting mechanisms. The type and amount of rates charged by IPAs vary by community. Some IPAs charge flat rates for service, while others charge by consumption (per kWh); in each case the level of rates charged is believed to vary by community.

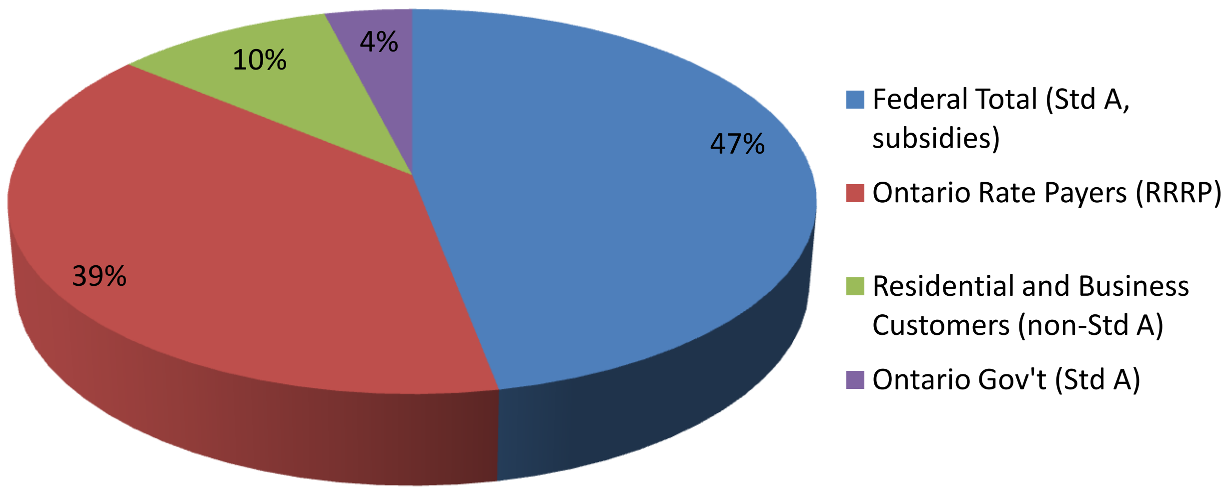
The OPA has little available information to determine the current finances of the IPAs, however it is believed that their relative operating costs are higher than H1RCI's based on the following factors:

- Relative lack of scale in purchasing and operations, as most IPAs have historically operated independently of each other, while H1RCI combines the scale of 15 communities and is able to share some common resources with its parent company.
- Greater sensitivity to diesel price volatility, as IPAs may not procure fuel through long-term supply contracts and may not benefit from volume purchasing and transport to the degree that H1RCI does.

Because of the lack of current and detailed IPA operating information the OPA has chosen to use H1RCI's costs as conservative proxy. It should be noted that because actual IPA costs are expected to be higher than estimated, the expected cost of the status quo diesel case is likely to be higher than shown and the potential benefit of transmission connection is likely to be better than shown. Using these assumptions, Figure 8 shows the estimated current allocation of costs between the Federal Government (AANDC), Ontario electricity rate base which funds RRRP, the Ontario provincial tax base which funds the Ontario portion of Standard A cost and remote community rate payers (residential/commercial). It is assumed in this cost allocation that AANDC provides funding for IPA costs that are not recovered by rates from customers (Standard A and residential/commercial rate payers) in those communities. The fact that IPA costs are expected to be higher than estimated suggests that the percentage of actual total costs funded by the federal government may be higher than depicted in Figure 8 below.

Figure 2: Estimated Current Share of Annual Cost of Diesel Generation in the 25 Remote Communities by funding source

Current Total Cost is estimated to be about $68 Million per year



Source: OPA[7]

3.0 ASSUMPTIONS AND FORECASTS USED IN THE ANALYSIS

<u>Asset Life and Study Period Duration</u>

Transmission and distribution facilities are long lived assets, which commonly have service lives in excess of 40 years before major refurbishment is required. Some existing facilities in northwest Ontario have been in continuous service for about double this period. For the purpose of this plan, an outlook or study period of 40 years (2013 to 2053, which includes 5-7 years of development and construction activities) has been adopted as it represents the

[7] Note: IPA costs were estimated based on the assumption that they are equal to HORCI costs per MWh of consumption using values reported in HORCI's 2009 Cost of Service Application

minimum expected operating life of a potential transmission and distribution expansion and it provides a reasonable period over which demand and cost factors can be forecast. This period is also expected to be a relevant period over which such long lived infrastructure can be financed.

Inflation

All analysis has been done in real dollars and assumes an average long-term inflation rate of 2% which is consistent with the Bank of Canada's target for the Canadian economy over the long term.

Load and Consumption Growth

Through discussions among Committee members, annual electricity demand growth of 4% for the entire study period was determined to be reasonable. This level of demand growth is based on population growth trends and anticipated intensification of electricity use that is expected to occur after connection to the IESO controlled grid. The experience of Five Nations Energy Inc.[8] over the 7 years since connection shows demand growth of approximately 5%. Given the rate of local economic development expected to materialize as a result of natural resource development opportunities in the area (including at the Ring of Fire) over the next few decades, the OPA and the Committee believe that this level of growth is conservative and is likely to be sustained over the long-term. While a projected demand growth rate of 4% has been used over most of the study period, 1% has been applied to the period between 2012 and 2015 to be consistent with H1RCI's 2012 rate case. Table 4 provides the long-term load forecast for the 25 remote communities in the northwest.

Table 4: Forecast Peak Load for the 25 Remote Communities in Northwest

	Forecast Peak Load for 25 Communities				
	2013	**2023**	**2033**	**2043**	**2053**
Peak Load (MW)	18	27	38	57	85
Energy Consumption (MWh)	84,000	122,000	179,500	266,000	394,000

[8] Five Nations Energy Inc. is a First Nation owned and operated transmission company serving three First Nation communities along James Bay (Forth Albany, Kashechewan and Attawapiskat) from the Hydro One Networks owned system at Moosonee.

Source: OPA

Diesel Fuel Price and Unit Energy Cost of Generation

The commodity cost of diesel fuel is based on the bulk purchase price in Thunder Bay. The delivered cost of fuel includes estimated transportation costs to the communities either by winter roads or by air when winter roads are not available. Due to weather and numerous other factors the amount of fuel delivered by winter road and air varies significantly from one year to the next.

In 2011, the average Thunder Bay Rack Price Ex-Tax (commercial rate) for Ultra Low Sulfur diesel was $0.879/liter. The OPA has used forecast growth rates from the US Energy Information Administration's Annual Energy Outlook Early Release 2012 report to forecast fuel prices in Thunder Bay between 2012 and 2035, which show an expected decline in fuel price between 2012 and 2013 after which moderate growth is expected. After 2035 a real annual growth rate of 1.1% is applied, which represents the long run average growth rate. Based on this forecast a commodity cost of $0.919/liter is assumed for 2017 when communities are planned to begin connecting. The OPA estimates that the average delivered cost of diesel to the communities in the study will increase by 2/3 during the planning period between 2013 and 2053.

Due to the location of each community and the availability of winter roads (which offer the lowest cost mode of fuel transport) the volume of fuel delivered by winter road versus air differs widely by community and year. Recently about 60% of the generation fuel for all communities has been delivered by air due to warm winter weather and short winter road seasons. Historically it has averaged closer to 50% for all of the communities[9]. Climate change is expected to lead to reduced reliability and useful duration of the winter roads in the future. Therefore, it is expected that over the long-term the amount of fuel delivered by air will increase as winter road deliveries decrease. The OPA assumes that initially 50% of fuel will be delivered by winter road and 50% by air and over the next 20 years the road

[9] Whitesand First Nation and Kiashke Zaaging Anishinaabek First Nation have access to all season roads and thus receive all of their fuel by road. The Hudson Bay communities receive their fuel by fuel barge and air.

delivered portion will decline to 40%. If the share of air deliveries increases more than forecast, then the delivered cost of fuel will rise above the forecast. Table 5 provides the forecast for the Thunder Bay Diesel Rack Price and the forecast delivered cost of fuel.

Table 5: Forecast Thunder Bay Diesel Rack Price (Real Dollars)

	Forecast Diesel Prices				
	2013	2023	2033	2043	2053
Diesel Commodity Price ($/L)	$ 0.80	$ 0.97	$ 1.08	$ 1.20	$ 1.34
Delivered Diesel Price ($/L)	$ 1.27	$ 1.52	$ 1.72	$ 1.92	$ 2.14

Source: OPA

The OPA estimates that the average unit cost of energy for diesel generation in the communities will rise from about $0.46/kWh in 2013 to $0.71/kWh in 2053, driven by growth in fuel prices and delivery costs as shown in Table 6 below.

Table 6: Forecast Diesel Generation Unit Energy Cost (Real Dollars)

	Forecast Unit Energy Cost				
	2013	2023	2033	2043	2053
Diesel Fuel Cost per kWh	$ 0.39	$ 0.46	$ 0.52	$ 0.58	$ 0.64
Variable O&M per kWh	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07
Diesel Unit Energy Cost ($/kWh)	$ 0.46	$ 0.53	$ 0.59	$ 0.65	$ 0.71

Source: OPA

<u>Ontario Electricity Price</u>

The OPA has forecast Ontario electricity prices for the study period based on current energy sector plans and policies until 2031. It is assumed that after 2031 prices will grow at about 1%/year in real dollars until the end of the study period.

Table 7: Forecast Ontario Electricity Cost (Real Dollars)

	Forecast Ontario Electricity Cost				
	2013	2023	2033	2043	2053
Electricity Price ($/kWh)	$ 0.12	$ 0.12	$ 0.11	$ 0.13	$ 0.14

Note: Excludes distribution charges. These charges are assumed to be charged to customers today and would not be incremental to the transmission connection case

Source: OPA

Social Discount Rate

The OPA uses the concept of a Social Discount Rate in its study and planning work. The OPA uses a Social Discount Rate of 4% for economic evaluation of power system electricity-related projects, because it is assessing them in the context of public interest. This rate takes into account infrastructural and environmental aspects with long-term implications for current and future generations. More detail on the Social Discount Rate can be found in the Integrated Power System Plan 1 (as filed with the Ontario Energy Board on August 29, 2007).

4.0 CASE FOR TRANSMISSION CONNECTION OF THE 20 REMOTE COMMUNITIES

Transmission connection of Ontario's remote northwestern First Nation communities would lead to cleaner, more reliable electricity supplies while reducing environmental risks, unlocking economic development potential and improving living conditions. For the purposes of this report's comparative quantitative analysis, the business case for transmission connection was developed based on a comparison of the directly avoidable costs of continued operation and expansion of diesel generation required to meet forecast community load growth compared with the cost of connecting the remote communities to and supplying them from the IESO controlled grid. Other existing operating costs (distribution system operation and maintenance, customer administration, etc.) will continue to be incurred and are expected to be more or less equal in either case. These costs are therefore not considered avoidable and are not accounted for in this economic evaluation. The costs will however remain and must continue to be paid for. There is also expected to be a need for the distribution systems in some communities to be brought into full compliance with Ontario's Electrical Safety Authority's ("ESA") standards prior to transmission connection. The scope and cost of work required to achieve compliance is not currently known. However, it is assumed that all electricity systems in Ontario should operate in compliance with ESA standards regardless of how they are supplied and thus these costs are therefore assumed to be common across all alternatives considered.

The omission from the analysis of the significant additional economic, social, developmental and environmental benefits to be derived from transmission connection of remote First Nation communities has the consequence that the benefits assessed by this comparison are likely to conservatively understate total identifiable benefits.

The following process was used to identify remote communities in northwest Ontario that are economically feasible to connect to the IESO controlled grid:

1. The cost of supplying the electricity needs of the remote communities through the continued use of diesel systems over the next 40 years was determined to establish a point of reference for cost, environmental and socio-economic impacts.
2. Conceptual transmission and distribution systems connecting combinations of remote communities in northwest Ontario were developed utilizing typical transmission and distribution design practices. The conceptual designs established the relative length of transmission and distribution lines required as well as the number of transformer stations and switching facilities. The line lengths accounted for obvious environmental constraints (such as avoiding environmentally sensitive areas including parks and significant water bodies) and guidance on preliminary routing was also provided by members of the NOFNTPC, who have knowledge of the area.
3. The cost of building the conceptual transmission and distribution systems and supplying the various remote communities from the IESO controlled grid was compared to the costs for continued operation on diesel mentioned in process step 1. Costs, on a unitized basis ($/km for lines), for building the conceptual transmission and distribution systems were obtained from an expert third party source.
4. The technical, environmental and socio-economic analysis was refined with information from experienced remote community representatives and the IESO. The Community representatives primarily provided guidance on other initiatives which could affect the connection plan, such as possible future transportation and utility corridors in the area as well as land use constraints, environmental constraints and socio-economic impacts. The IESO, which is responsible for ensuring new connections to the IESO controlled grid are in compliance with reliability and operability requirements, conducted a feasibility study to establish the feasibility of the transmission concepts and the need for additional transmission facilities, which could affect the cost of the connection plan. This included identifying the need for additional switching facilities, voltage control devices and special protection systems.
5. The cost analysis for connection was refined based on input received in process step 4 above.
6. To assess the degree to which the economic case for connection was robust, an uncertainty assessment was also conducted[10]. This uncertainty assessment subjected the primary factors affecting the economic case (demand growth rate, delivered cost of diesel fuel and cost of transmission facilities) to a reasonable range of values to determine the effect on the economic case.

10 The uncertainty analysis is discussed in more detail in Section 4.5

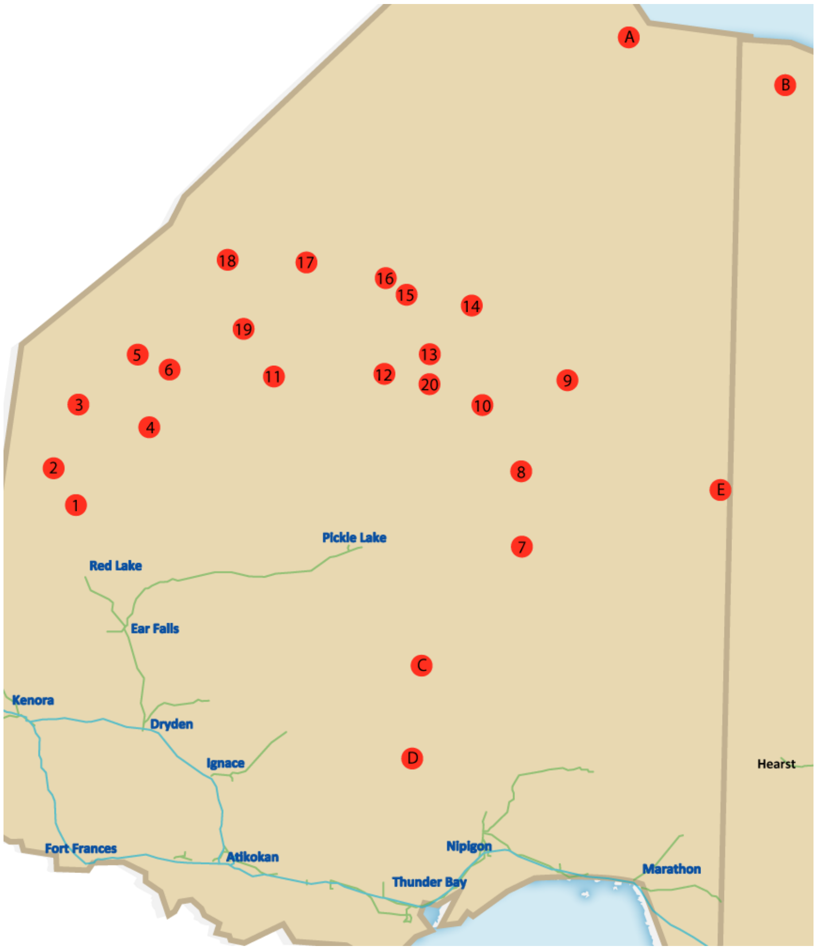
Details associated with these process steps are outlined in the following sections.

In addition to the above comparison between continued operation of diesel generation versus connecting remote communities to the IESO controlled grid, a high level strategic assessment was also conducted to compare these two alternatives against supplying the remote communities from a combination of the existing diesel systems coupled with community based renewable resources. This assessment is detailed in Section 4.6.

4.1 Determination of Which Communities Are Economic for Transmission Connection at This Time

Based on the overall process outlined above analysis was conducted to determine the relative cost and technical requirements to connect the 25 remote First Nation communities in northwest Ontario that have operating distribution systems powered by diesel generation. This analysis identified that 20 of the 25 are economically and technically feasible to connect. Figure 9 shows these 20 communities (1-20) as well as the 5 that are not economic to connect at this time (A-E).

Figure 9: Northwest Ontario Remote First Nation Communities



Economic to Connect	
1	Pikangikum
2	Poplar Hill
3	Deer Lake
4	North Spirit Lake
5	Sandy Lake
6	Kee-Way-Win
7	Eabametoong (Fort Hope)
8	Neskantaga (Lansdowne House)
9	Webequie
10	Nibinamik (Summer Beaver)
11	North Caribou Lake (Weagamow or Round Lake)
12	Kingfisher Lake
13	Wawakapewin (Long Dog)
14	Kasabonika Lake
15	Wapekeka
16	Bearskin Lake
17	Kitchenuhmaykoosib Inninuwug (Big Trout Lake)
18	Sachigo Lake
19	Muskrat Dam
20	Wunnumin Lake
Not Economic to Connect at Present	
A	Fort Severn
B	Weenusk (Peawanuk)
C	Whitesand (Armstrong)
D	Kiashke Zaaging Anishinaabek
E	Marten Falls

Source: OPA

Of the 20 remote community electrical systems identified for connection, 11 are served by H1RCI, while 9 communities are served by IPAs. These communities are listed by their current electricity service provider in Table 8

Table 8: Northwest Ontario Remote Communities Identified for Connection

Hydro One Remote Communities Inc.	Independent Power Authorities
Bearskin Lake	Eabametoong (Fort Hope)
Deer Lake	Keewaywin
Kasabonika Lake	Muskrat Dam
Kingfisher Lake	Nibinamik (Summer Beaver)
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	North Spirit Lake
Neskantaga (Lansdowne House)	Pikangikum (line under development)
Sachigo Lake	Poplar Hill
Sandy Lake	Wawakapewin
Wapekeka	Wunnumin Lake
Weagamow (North Caribou Lake)	
Webequie	

Source: OPA

There are three main factors that make the 20 communities economic to connect to the IESO controlled grid:

- Communities are arranged in natural geographic clusters that allow efficient routing of transmission and distribution lines to connect them;
- Communities within each cluster are relatively close to each other;
- The largest communities having the highest electricity consumption tend to be the greatest distance from the existing grid. The high diesel based electricity consumption makes it economic to extend transmission to these distant communities. Since the transmission line route to these large communities passes by a number of the smaller communities, they in turn become economic to connect.

The primary reasons identified in the evaluation that make the remaining five communities uneconomic to connect at this time are their distance from the IESO controlled grid and their relatively small load. Some of them may become economic to connect in the future if their load grows or if other opportunities materialize which enable a sharing of costs, such as development of industrial loads or generation projects in the area.

The cost to connect the 25 communities is shown in Table 9. The 20 that are economic to connect have costs that are lower than the other 5.

Table 9: Average Community Connection Costs $/KW

	Average Community Connection Costs ($/kW)
Average of 20 Communities	$30,000 to $34,000
Whitesand First Nation & Kiashke Zaaging Anishinaabek First Nation	$37,000 to $40,000
Marten Falls First Nation	$55,000 to $60,000
Fort Severn and Peawanuck	>$80,000

Source: OPA

In the case of Whitesand First Nation and Kiashke Zaaging Anishinaabek First Nation, the most likely grid connection would be via a dedicated line from the transmission system south of Lake Nipigon. The identified connection costs for these communities therefore have no interdependence with connections to any of the other 20 communities and therefore there is no benefit from combining the projects. The higher cost per kilowatt to connect Whitesand First Nation and Kiashke Zaaging Anishinaabek First Nation is due to their small load relative to the long line length required to accomplish the grid connection. As the load in these two communities grows in the future, the economics of grid connection may improve[11]. There may also be an opportunity in the longer term to economically connect Marten Falls First Nation to the Ontario grid as economic development in the Ring of Fire area advances and infrastructure to connect the area with the rest of Ontario is built. The OPA plans to work with each of these five communities identified as not economic to connect on an individual basis to identify their unique and individual needs and help them to develop solutions that will assist in cost effectively reducing diesel consumption in their communities. Further details are discussed in Section 6. OPA will work with these communities to monitor load growth, diesel costs and other load and generation opportunities in the areas of Whitesand First Nation, Kiashke Zaaging Anishinaabek First Nation and Marten Falls First Nation to determine if connection becomes an economic

11 It is relatively easier and lower cost on a per Km basis to build line to serve communities with all season road access than those in the remote far north; however the avoidable diesel costs included in a business case to connect these communities is also much lower.

option for these communities. [12] The OPA will also work with these communities in the near term to implement options that can economically reduce their reliance on diesel.

4.2 Avoidable Diesel Generation Costs

Continuing to supply electricity in the group of 20 remote communities using isolated diesel generation systems would require expanding the existing load serving (prime rated) generation capacity from 21 MW currently to about 100 MW by 2053. As mentioned in Section 2.0, new capacity is needed when peak load reaches 85% of prime rated capacity, or about 18 MW based on existing prime rated generation capacity. Existing peak load in the 20 communities is estimated to be about 15 MW and it is forecast to surpass 18 MW around 2017. New generation capacity is already required in several communities which are operating under load restrictions. It is estimated that as many as half of the communities would be load restricted (i.e. not able to connect new customers) in the next 5-7 years if new capacity is not added. Meeting load growth would entail not only an almost 5 fold increase in generation capacity, but also in fuel transportation and storage capacity. If storage capacity is not increased proportionately then the proportion of fuel delivered by air transport will increase above the forecast. This will put the communities at increased risk of not having sufficient onsite reserves during periods when flights may not be possible. Such expansion would involve substantial ongoing financial investment, and would also require substantial new space in each community for fuel storage and new on-site generation units. There would also be an increased environmental impact related to transporting and storing almost 5 times more fuel than is currently used. In recognition of increasing need to upgrade and replace storage infrastructure in remote communities, the Federal government in its 2011 budget, committed to investing $22 million over 2 years in new fuel storage in remote communities across Canada.

Rising diesel fuel commodity, transportation and storage costs have led to a substantial increase in the unit energy costs recently. As a result, the total cost of supplying the growing demand of remote communities has been increasing as well. Load growth is also

12 Potential industrial and commercial developments in the west Nipigon area may provide additional drivers for connection. For example Whitesands First Nation is investigating the option of building a saw mill and biomass co-generation plant which could significantly increase both load and generation capacity in the area and potentially increase the value of connection.

driving the need for generation capacity expansion. Information from Committee members indicates that recent upgrades of diesel system capacity in their communities have cost in the range of $7,000 to $10,000 per KW of incremental prime rated capacity. For this analysis, the OPA has assumed an average all in cost of $7,400/KW for diesel capacity expansions, which includes required equipment, storage and integration costs.

Escalating unit energy costs combined with a more than fourfold increase in demand by 2053 plus the high and rising cost of capacity expansion in remote communities is expected to drive the total cost of supplying the 20 communities from a modeled estimate of roughly $60 million in 2011 to about $350 million in 2053.

To assess and compare the cost of continued diesel generation with the cost of transmission connection for the group of 20 communities, the OPA identified and forecast the diesel generation costs that could be avoided after the 20 communities are connected to the provincial transmission system. This avoidable cost includes:

- Approximately 97% of the forecast diesel that would be consumed without a transmission connection (assumes diesel units operate 3% of the time to maintain supply during transmission system outages);
- Avoidable operations and maintenance costs;
- Long-term cost of diesel generation expansion to meet load growth; and
- Long-term cost of generator overhaul and replacement required to operate the expanding fleet.

Given the potential for planned and unplanned transmission system outages, it is prudent to maintain the diesel capacity currently in operation in the communities for load restoration purposes. Currently, there is approximately 37 MW of installed diesel generation capacity in the 20 communities, which if properly maintained may be sufficient to meet emergency load restoration needs until after 2030. It is assumed that the systems will run approximately 3% of the time to cover emergency and regular maintenance outages. This is consistent with the experience of Five Nations Energy Inc. in operating its system over the past 10 years.

The direct costs that are expected to be avoided if diesel generation is replaced by transmission supply in the communities that are economic to connect are summarized in

Table 10. Communities are assumed to begin connecting to the IESO controlled grid after 2016, at which time the savings in avoided diesel generation are expected to begin.

Table 10: Avoidable Diesel Supply Costs for the 20 Remote Communities

	Avoidable Diesel Supply Cost ($M)
Nominal Avoidable Cost to 2053	5,700
Present Value Avoidable Cost to 2053	1,900
Annualized Avoidable Cost (2017 to 2053)	98

Source: OPA

As mentioned previously, complete and accurate costs for the IPAs are not available to the OPA. The best proxy available at the time of writing for IPA operating costs are unit estimates based on H1RCI's 2009 rate case and the diesel price and consumption estimates developed by the OPA. These estimates have been applied equally to all communities in the analysis. However, as discussed earlier, IPAs likely have higher unit operating costs than H1RCI operated systems. H1RCI's greater scale should result in significant cost efficiencies in its operations, maintenance and administration activities.

Beyond the avoidable economic costs of supplying electricity with diesel in these communities, there are other costs and risks that impact the welfare of the communities and their residents. These impacts include but are not limited to:

- Environmental risks and costs of transporting, storing and operating diesel generation in these communities;
- Constraints on community growth when capacity is not expanded in a timely manner

There are economic aspects associated with these impacts, but there is little information available to quantify them at this time. As a result, a qualitative assessment of these impacts is discussed below.

<u>Environmental Effects of Diesel Use for Electricity Generation</u>

Diesel generation creates significant emissions in remote communities, causing local pollution and greenhouse gas releases. Based on standard estimations of greenhouse gas emissions from diesel combustion, it is estimated that at current generation levels approximately 65 kT of GHGe emissions are produced annually. Continued use of diesel generation will lead to rising annual emissions resulting in approximately 6 MT of avoidable incremental GHG emissions compared to supplying the communities from the Ontario generation mix over the next 40 years. Reducing or eliminating diesel combustion is expected to improve air quality and noise pollution in the communities.

Reliance on diesel generation also exposes the communities and the environment to the risk of spills/leakage during transport, handling and storage. The cost and challenges associated with clean-up due to an event is difficult to estimate.

Pricing of carbon emissions have also not been included due to uncertainty over when/if a carbon pricing mechanism will be implemented and if one is implemented what price might be applied to diesel emissions. This results in an additional degree of conservatism within the overall analysis.

Due to the omission of the cost differences between H1RCI and the IPAs, as well as the other costs and impacts identified above, this analysis represents a relatively conservative view of the expected outcomes. Accurate accounting of these costs is expected to result in the overall cost of continued reliance on diesel being higher than the estimates provided.

Constrained Growth

Historically in many remote communities, there has been a lag between demand for new capacity and the expansion to provide new capacity. Delayed expansion may lead to constrained community growth and pent up demand. Some communities have indicated that their local power systems are currently operating under load restrictions. In affected communities, this can result in new housing and commercial building stock remaining unoccupied (and unused) for extended periods. There may also be lost economic opportunities when businesses do not form or expand to take advantage of regional opportunities due to insufficient electricity supply or high costs. Constrained electricity supply conditions may also exacerbate residential crowding in these communities, which could increase health and safety risks and impose other costs which are not accounted for in this study.

Growth in mining and other industrial activities around some of the 20 communities are creating new economic development opportunities. Constrained electricity supply capacity may result in an inability for these communities to provide nearby industries with the goods and services they require in a timely manner. This could result in a loss of opportunity for these communities to participate in the industrial expansion occurring in their areas.

4.3 Transmission Connection and Supply Costs

Studies undertaken by the OPA and the IESO have determined that the current transmission system north of Dryden, comprised of transmission lines E4D, E2R and E1C, does not have sufficient capacity to serve remote communities, projected mining load or the forecast growth in the Red Lake and Pickle Lake areas beyond 2012. Thus reinforcement of the system is required to serve these identified needs.

The OPA has conducted a planning and feasibility study in parallel with the development of this report to ensure that there are options available to meet the load growth needs forecast for the connection of remote communities. Included in the OPA's estimates of the capital and operational costs to connect remote communities are estimates of a relevant share of the costs to reinforce Pickle Lake and Red Lake.

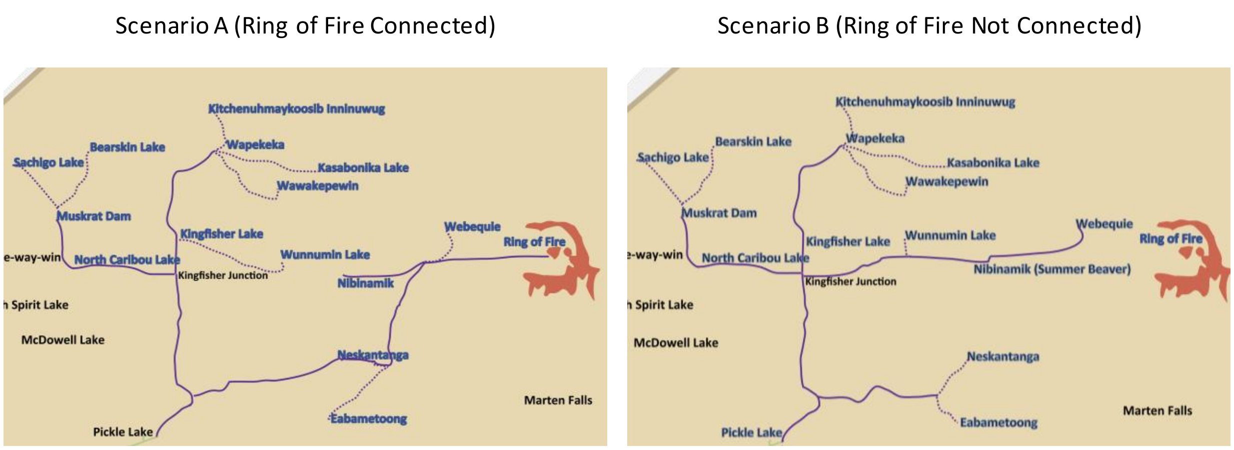
Through a conceptual connection route analysis, the OPA found that radial transmission configurations from Red Lake and Pickle Lake can best connect these communities, as they provide the best overall balance of cost, operability and reliability[13]. It is expected that approximately 1,000 km of 115 kV line and 750 km of distribution line will need to be built north of Red Lake and Pickle Lake. Required transformer stations, reactive compensation devices, related switchgear and protection and control systems have also been included in these capital estimates.

The six communities north of Red Lake can be served by a single radial 115 kV line from Red Lake and the 14 communities north and east of Pickle Lake can be served by several 115 kV lines from Pickle Lake.

13 A radial transmission system is one where one or more customers (generators or load) are connected to a single point on an electricity system, which differs from a network system where there are multiple connection points.

Two potential configurations have been identified (shown in Figure 10) for the cluster of 14 communities north and east of Pickle Lake based on whether or not a new line from Pickle Lake will be built to supply potential mining developments at the Ring of Fire. Scenario A, includes supplying all 14 remote communities north and east of Pickle Lake and the Ring of Fire from Pickle Lake. This scenario assumes that 4 remote communities between Pickle Lake and the Ring of Fire would share a new 115 kV line with ROF proponents. Scenario B includes only the 14 communities north and east of Pickle Lake and excludes connection at the Ring of Fire, which leads to a different connection configuration. These scenarios are shown in Figure 10. While total capital costs are about $50 million higher for Scenario A, the cost attributable to the remote connection plan for Scenario A is estimated to be about $150 million less than for Scenario B due to the potential for cost sharing with other customers. It is important to recognize, however, that this potential for cost sharing is dependent on forecast load at the Ring of Fire materializing and the Ring of Fire mines paying their share of project capital costs as prescribed by Ontario Energy Board codes.

Figure 10: Northwest Ontario Remote First Nation Connection Configurations



Source: OPA

The OPA has identified the potential for 35-65 MW of industrial load at the Ring of Fire to develop after 2016. Analysis shows that to serve this load from Pickle Lake, 230 kV supply at Pickle Lake would be required and that a single 115 kV line from Pickle Lake to the Ring of Fire could supply the needs of the four remote communities and up to about 35 MW of load at the Ring of Fire. Supply beyond these levels will require either upgrades to the line or a second line of supply from Pickle Lake to the Ring of Fire.

As discussed above, Scenario A requires 230 kV supply at Pickle Lake to supply the Ring of Fire from Pickle Lake. This line will be sufficient to serve all of the Pickle Lake area load including the 14 remote communities north and east of Pickle Lake and the Ring of Fire until well beyond the planning period. Red Lake area growth including connection of the 6 remote communities north of Red Lake can be served by upgrading the existing lines between Dryden and Red Lake (E4D and E2R).

In Scenario B, the new 115 kV line from Ignace/Dryden to Pickle Lake would not have sufficient capacity to supply all of the Pickle Lake area load growth until the end of the planning period and would require 20 MW of load from the Pickle Lake area be transferred back to Ear Falls supply around 2021. As a result a new 115 kV line from Dryden to Red Lake will be required around 2021, in addition to upgrades to E4D and E2R to serve all of the Red Lake are load growth plus 20 MW of Pickle Lake area load supplied by E1C.

However, pre-building the new line to Pickle Lake to 230 kV standards and operating it at 115 kV may be worthwhile as it preserves the option for the line to be operated at 230 kV in the future to serve Pickle Lake area load instead of requiring load to be transferred to Ear Falls. This would provide incremental capacity at Ear Falls to serve load growth in the Red Lake area for the long term and defer the need for a new line from Dryden to Red Lake. Maintaining the option of upgrading Pickle Lake to 230 kV supply would also ensure that load growth in the Pickle Lake area beyond the 2033 or unforeseen load growth in the near or medium term (such as a new mine development requiring connection) can be served adequately without having to build an additional line.

A proportion of the costs for reinforcing the supply points at Red Lake and Pickle Lake must be accounted for in this business case. This has been accomplished by assuming that each participating customer utilizing new capacity in the north of Dryden system will pay a share of the total cost of all of the north of Dryden system upgrades and expansions, proportional to their share of the load growth forecast in 2033. The OEB's Transmission System Code identifies the principles by which costs for customer connection facilities are to be allocated among multiple parties, which is generally based on proportional use[14]. Cost allocation for specific line projects north of Dryden may also depend on how the system is configured and operated and which customers are willing to participate at the time of construction and financing. Thus it is difficult to determine at this point of time which customers in which locations will contribute to each project and by how much. However, this business case has assumed an allocation based on the remote communities forecast load as of 2033.

The OPA has developed a 20 year load forecast (2012 to 2033) for the north of Dryden area which includes the forecast load for the remote communities assumed to be connected in this plan (33 MW in 2033). Load growth for the north of Dryden system in Scenario A, between 2012 and 2033, is estimated to be 133 MW. This includes 35 MW of industrial load at the Ring of Fire.

This plan assumes a 115 kV line to the Ring of Fire will supply four remote communities and industrial customers at the Ring of Fire. Should load growth at the Ring of Fire grow beyond 35 MW the incremental load will need to be supplied by a reinforcement of this system. In accordance with the Transmission System Code's principles, it is expected that further expansion for mining load would be fully funded by the mining customers that require them.

In Scenario A, the remote communities share of the total North of Dryden load growth is about 33 MW (25% share), thus this plan assumes an allocation of 25% of shared costs for upgrades and expansions to E4D, E2R and a new 230 kV line to Pickle Lake. With regard to the line to supply the Ring of Fire it is estimated that the 4 remote communities participating would contribute about 5 MW of load or about 15% of the 40 MW of load that can be served on the single 115 kV line. Thus the connection plan allocates 15% of the cost of the shared line to this connection plan. The balance is assumed to be paid for by the Ring of Fire proponents, contingent on the assumptions that forecast load at the Ring of Fire materializes and that the Ring of Fire mines pay their share of project capital costs as

14 It is recognized that the OEB may consider other allocation models. It is also acknowledged that the parties undertaking the development, construction and ownership of the line projects considered herein, may enter into their own cost sharing arrangements with future customers based on their own needs and interests.

prescribed by Ontario Energy Board codes. In addition to the 15% share of the Ring of Fire Line that is included in this connection plan, there are also costs for transmission stations and distribution voltage lines required to connect the communities to the line, which are also allocated to the remote community connection plan

In Scenario B, remote community load in 2033 (33 MW) represents a 35% share of forecast north of Dryden load growth up to 2033 and this connection plan assumes a cost allocation of 35% of the upgrade costs for E4D and E2R, a new 115 kV line to Pickle Lake and a new line 115 kV line from Dryden to Red Lake.

Table 11 summarizes the costs that have been estimated for the remote community connection plan and the other participating parties collectively. The "Other Parties" category shown in the table is assumed to include, but is not limited to, direct connected industrial customers, and participating Local Distribution Companies.

Table 11: Total Project Capital Costs and Contributions from Other Parties Sharing Assets

	Scenario A with RoF ($M)			Scenario B no RoF ($M)		
	Remotes	Other Parties	Total	Remotes	Other Parties	Total
Remote Connection Only Facilities ($M)	710	0	710	945	0	945
Shared Transmission Facilities ($M)	175	395	570	95	190	285
Total Project Capital Cost	885	395	1280	1040	190	1230
Load Growth (MW)	33	100	133	33	65	98
Cost per MW Served ($M/MW)	27			32		

Source: OPA

The capital cost for Scenario A including a 115 kV line to the Ring of Fire is estimated at just under $1.3 billion. Given the opportunity to connect more load in this scenario (additional 35 MW of load at Ring of Fire) and share costs over a larger customer base (relative to Scenario B), the capital cost to connect all 20 remote communities in this scenario is estimated to be less than $900 million, and is dependent on fully realized Ring of Fire contributions to the overall project.

The capital cost of scenario B is similar to Scenario A at over $1.2 billion. However, given that costs would be shared among fewer parties, the cost associated with connecting the

20 remote communities is expected to be higher at over $1 billion, which is about 15% more than the cost of Scenario A. The shared facilities in this scenario include only a new 115 kV line to Pickle Lake and twinning of E4D and E2R.

In addition to the capital cost, operations and maintenance and electricity supply costs must be included to determine the total cost of supplying these communities over the study period. The incremental cost to connect and supply the 20 remote communities from the IESO controlled grid is summarized in Table 12 for the 40 year period from 2013 to 2053.

Table 12: Total Cost of Providing Electricity in 20 Remote Communities via Transmission Connection

	Scenario A with RoF ($M)	Scenario B no RoF ($M)
Total Incremental Cost to 2053*	2,600	2,900
PV of Total Incremental Cost to 2053	1,320	1,470
Level Annual Cost (2011 to 2053)	68	76

Source: OPA

* Capital costs are net of contributions from other parties sharing common assets

4.4 Benefits of Connecting the 20 Remote Communities

The economic analysis in Tables 10 and 12 shows that the average cost over 40 years of connecting the 20 remote communities to the IESO controlled grid is expected to be $22 million to $30 million/year less than continued diesel operation. Table 13 compares the avoidable cost of diesel generation with the cost of connecting and supplying power to the communities from the IESO controlled grid

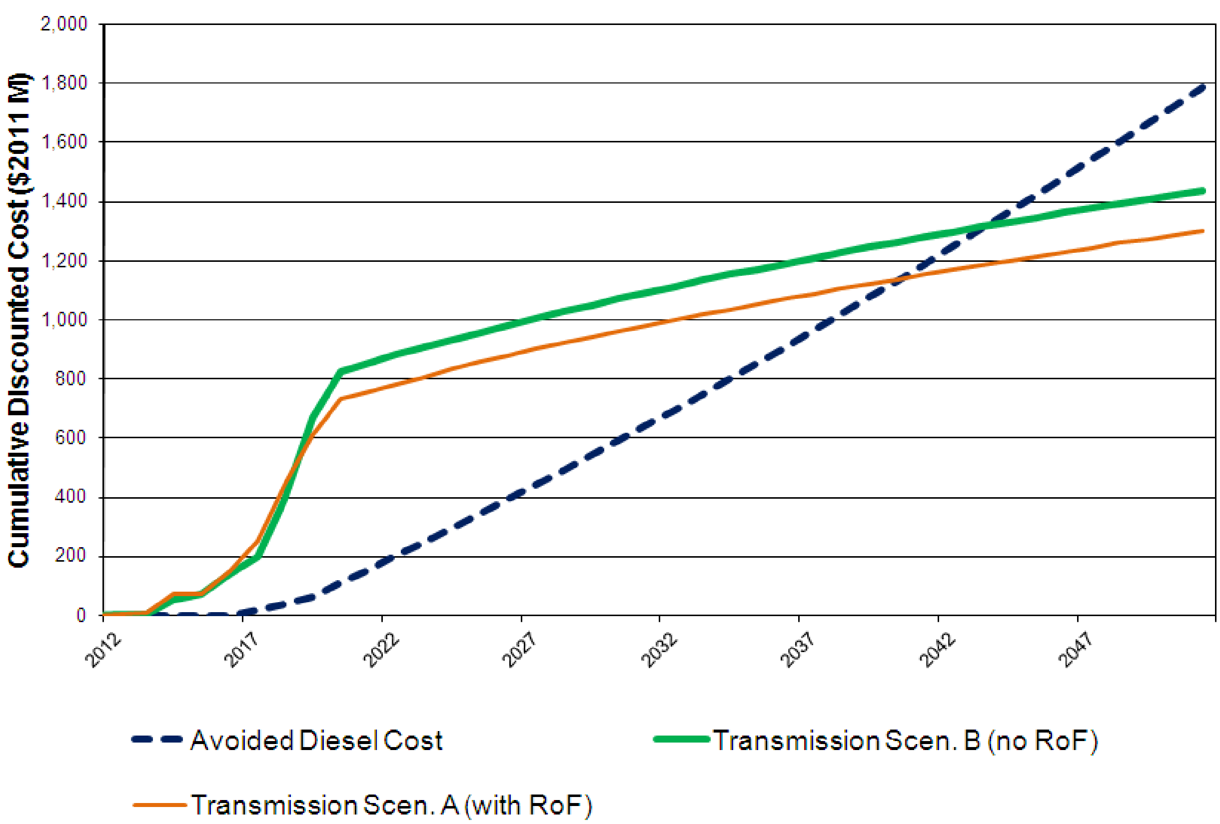
Table 13: Net Present Value of Electricity Supply to Remote Communities Over the First 40 years

	Scenario A with RoF ($M)	Scenario B no RoF ($M)
Transmission Present Value (Table 9)	1,320	1,470
Avoided Diesel Present Value (Table 7)	1,900	1,900
NPV	580	430
Net Annualized Benefit	30	22

Source: OPA

Based on the direct avoidable costs assessed, the combined project is expected to break-even 20-25 years after all of the communities are connected. Figure 11 shows the cumulative costs, and breakeven point. Over a 40-year period, transmission connection could supply the remote communities at about 70-77% of the cost of continued diesel generation. Figure 11 provides a graphical representation of these two points by showing the cumulative cost of avoided diesel generation versus the cost of supplying the communities by transmission connection. Transmission assets typically last much longer than the 40-year period used in this analysis. The cost of continuing to supply these communities by transmission after 2053 (once the assets are fully paid for) is very attractive as typically only the operating and maintenance costs of the transmission facilities will remain, whereas the full and rising cost of diesel expansion and operation would need to be covered in the status quo option.

Figure 11: Cost of Transmission Connection Vs. Avoidable Cost of Diesel Generation



Source: OPA

As noted previously, the assessment shown in Table 13 is conservative insofar as it does not quantify economic, social, developmental and environmental benefits of transmission connection beyond avoided diesel costs. These additional benefits include reduced infrastructure barriers to growth, increased economic development opportunities (both within the remote communities as well as regionally), improved social and living conditions for remote community residents, cleaner air and reduced greenhouse gas emissions, reduced future environmental remediation liabilities associated with diesel fuel spills, and improved reliability of electricity supply.   While the focus on direct costs of avoided diesel in this analysis helps ensure a conservative assessment of the business case, decisions to invest in the project should also incorporate these additional expected benefits into the rationale for proceeding with the project, many of which are very relevant to communities and their operating costs. For example, benefits could be quantified through estimates of concepts such as avoided environmental contamination liabilities, or the value of economic activity and foundational infrastructure in remote First Nations communities.

Rates for all customer classes that are connected to the IESO controlled grid are expected to continue to be set through the OEB's normal rate setting mechanism.

The current funding parties (the Federal government (AANDC), the Ontario provincial rate base, the Ontario provincial tax base and rate payers in the communities) are the direct benefitting entities associated with connecting the identified communities to the IESO controlled grid. It is expected that costs related to connection would be shared among these benefitting parties in proportion to the benefits each would receive.   Industrial customers would also be expected to contribute to the cost of the project in proportion to the load they connect to the facilities.

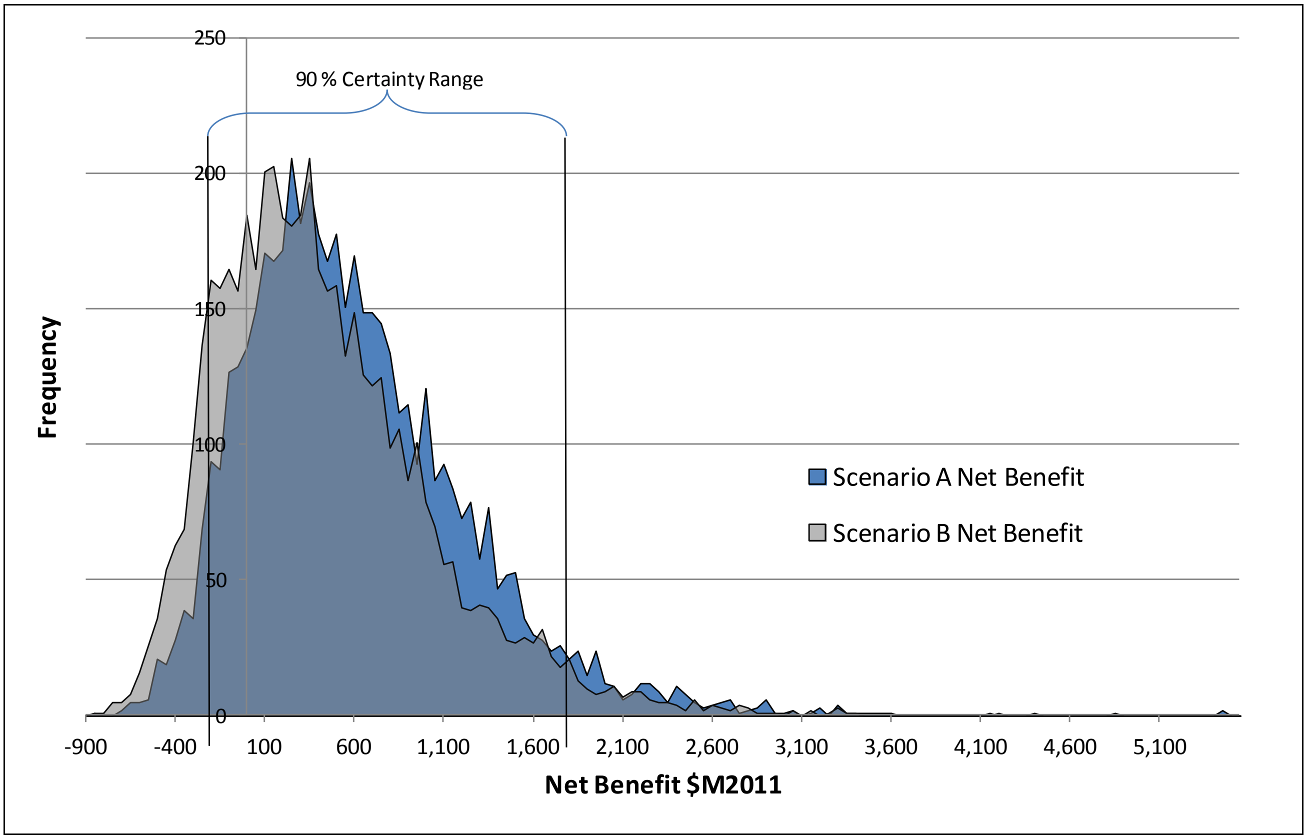
4.5 Uncertainty Analysis

To determine the degree to which the findings within this analysis are robust, the OPA on conducted an uncertainty analysis using a Monte Carlo simulation tool. This analysis provides a statistical representation of the net present value of the business case over a wide range of assumptions for several key variables which have been found to drive the outcomes:

- Electricity demand growth rate
- Delivered cost of diesel fuel (i.e. diesel price growth rate and the diesel transport mode)
- Transmission capital costs

The distribution of the Net Present Value of Scenario A and B relative to the diesel case are summarized in Figure 12. These findings indicate that under a wide range of inputs and probability assumptions the project NPV in both scenarios A and B is expected to be positive (transmission costs less than diesel) in about three-quarters of the 5,000 input combinations analyzed for each scenario. This finding on its own is a strong indicator of the probability of net economic benefits materializing by 2053. Further, while there is a roughly ¼ probability that transmission connection could be marginally higher cost than the continued diesel case, the probability of the diesel case being substantially higher than the cost of transmission connection over the same 40 year period is roughly three times higher.

Figure 12: Net Present Value of Transmission Connection Vs. Avoidable Cost of Diesel Generation



Source: OPA

Transmission connection provides a natural hedge against the upside risk associated with the diesel case by fixing the largest part of the project's lifetime service cost (capital) at the time of construction. In addition, it should be recalled that actual IPA diesel service costs are expected to be higher than estimated in the OPA's analysis, such that the probability of a positive NPV for the transmission case should be higher than this analysis predicts.

As mentioned previously, there is unaccounted for value in ensuring the remote communities have stable and unrestricted access to reasonably priced electricity. Further, transmission connection can limit or eliminate a number of other risks such as the long-term environmental impact of transporting, storing and burning increasing volumes of diesel in remote communities. As one example, a major fuel spill during transportation by winter road can do serious harm to sensitive terrestrial and aquatic ecosystems in the remote north. The cost, time and difficulty in bringing in equipment and people to perform cleanup can often cost many times the value of the fuel and equipment lost.

The analysis indicates that over a 40 year planning horizon (2013 to 2053), Scenario A has an expected NPV of $580M and there is a greater than 83% probability of a positive NPV[15] over that period. Further, there is a 90% probability that the project's NPV will be between -$240M and $1,715M as shown in Figure 12.

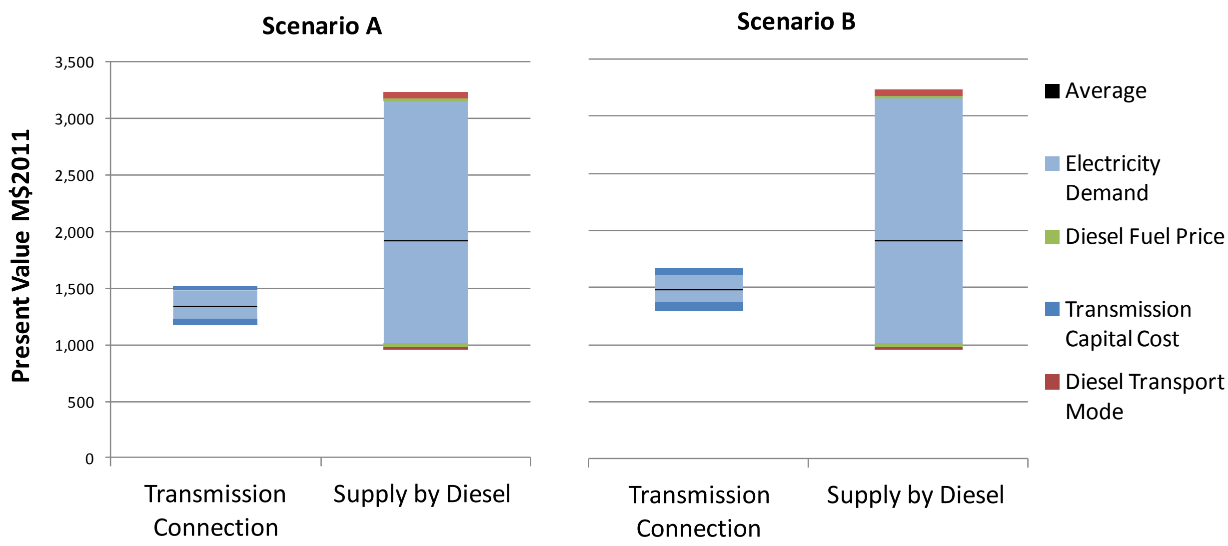
Similarly, the analysis of Scenario B indicates an expected NPV of the project of $406M and has a greater than 73% probability of a positive NPV. The same 90% certainty range shows the project's NPV will be between -$371M and $1,560M.

The analysis also looked at the cumulative contribution of each variable to the observed uncertainty in the simulations; the results are shown in Figure 13. Demand growth is the overriding driver of variation in both the transmission connection and supply by diesel cases. It is also the main driver of the amount of difference in uncertainty between the diesel generation case and the transmission connection cases. In the diesel generation case, demand growth plays a large role because it is compounded over the period and acts directly on the cost of fuel consumed (the price of which is also compounded over time) and on the generation expansion costs which are also rising. Whereas the transmission connection cases are characterized by mostly fixed costs that are set when the project is built. The only major factor influenced by demand growth is the cost of power consumed, which is a comparatively small cost in this case.

The variation shown for the remaining variables is their net contribution in addition to the range of variation for the demand growth variable. More detail on the range of independent variation for each variable is shown in Appendix A.

[15] Positive NPV means the cost of status quo is greater than the alternative cost of transmission connection for the 20 communities.

Figure 13: Distribution of Net Benefit for Scenarios A and B



Source: OPA

In both scenarios, negative NPV outcomes are most common when demand growth is consistently more than one standard deviation below the average over the entire planning period and other variables are also at or below their expected values.

The business case for transmission connection is compelling not only because it is substantially more likely to cost less than continued diesel generation over the next 40 years, but because it also reduces several unquantified economic and environmental risks (such as fuel spills, site contamination and GHG emissions) and provides unaccounted for benefits. Transmission connection enables a higher quality of life through a stable, unconstrained supply of power over the long term. This certainty is expected to create new economic opportunities in remote First Nation communities that could reduce the long-term costs associated with maintaining services in these communities.

Further, while a 40 year period has been chosen as a reasonable point in time to evaluate this project based on expected asset life before refurbishment is required;; these transmission facilities are expected to continue to provide value for many years beyond.

There may also be future opportunities for excess available capacity in the proposed transmission facilities to be used by industrial customers or generation projects. Industrial and resource operations that may have been previously uneconomic to develop due to the high cost of diesel generation may be economic once reliable and relatively low cost power is available nearby through a transmission connection. Should these potential loads choose to connect they would be expected to contribute to the cost of the projects in this plan, which could further reduce cost and long-term risk associated with the project. This opportunity is not available with the existing diesel generation available in the remote communities. Having grid access may also improve the economics of future generation projects that may be desirable to develop in the future.

More detail on the methodology and results of the uncertainty analysis is provided in Appendix A.

4.6 Renewable Generation Integrated with Diesel Generation

A third strategic supply option that was evaluated for supplying remote communities was the utilization of the diesel systems coupled with community based renewable resources. Under this strategic supply option the existing diesel generators would be integrated with local renewable resources, and battery storage, to minimize the use of diesel. This investigation considered options for interconnecting communities to larger high potential renewable resources without connection to the IESO controlled grid.

Research into other jurisdictions found that renewable generation can be economically integrated with diesel power systems to power remote communities either in regional mini-grids (where distances between communities and generation sites are not great) or as isolated individual community systems. These options could provide some cost and environmental risk reduction over the status quo and they may also create opportunities for more economically developing some renewable energy sites in remote First Nation territories. It was thought that some small hydro sites would be more economic to develop to supply several communities than micro-hydro and wind sites dedicated to a single community, even after considering the cost of connecting the communities and the generation.

A high level review of potential renewable generation sites in the area confirms that the most economic sites are in the order of several megawatts to tens of megawatts in size.

Developing a self-standing remote grid requires finding a balance of appropriately sized renewable generation and connected community load. A review of the remote communities in the area and the highest potential renewable energy sites indicates that this balance would be difficult to achieve. For the community electricity systems to remain isolated from the IESO controlled grid, development of the larger scale, more economic renewable sites would require the pooled demand of at least 3-5 communities. However, this would require hundreds of kilometers of transmission and distribution line be built to connect the generation with sufficient load. This requirement adversely affects the overall economics of such projects.

Further, in all cases diesel generation would still be needed to meet demand when variable renewable resources are insufficient or unavailable, such as when run of river hydro sites have insufficient flow to meet demand or wind is not available. It is expected that even with efficiently sized renewable generation the community diesel generation units would need to provide at least 15% of the energy requirements in each community. While battery storage can eliminate some inefficient diesel operation (low load operation below the engine's optimal efficiency level), the technology is costly and the diesel units would need to run regularly to meet demand variations and maintain operability of the local system. This inefficient operation would limit the amount of diesel fuel that could be offset. As a result, it is expected that the long-term cost of renewables integrated with diesels in either mini-grids or isolated systems will remain high because of:

- Substantial new investments in generation and transmission infrastructure (for the mini-grid option);
- Limited reduction in diesel consumption; and
- Cost of installing battery storage technology to achieve efficiencies.

Table 14 shows the average energy costs for relevant sub-sets of the 25 remote communities considered in the analysis of each technology and compares them to the status quo option of continued diesel operation.

Table 14: Comparative Average Total Cost of Electricity Supply For Alternative Supply Technologies

	Average Total Cost of Supply to 2051 ($/kWh) Low	High	Remaining on Diesel Supply
Diesel Generation	0.83	0.87	All
Isolated Wind Integrated with Diesel	0.59	0.63	All
Hydro Connected to Community Clusters	0.43	0.48	>10
Transmission Connection	0.39	0.43	5

Source: OPA

The OPA has found it unlikely that all communities could be served economically by renewable generation integrated with diesel, due to large variances of resource availability. This finding does not preclude the prospect that renewables may be more fruitfully integrated in communities following connection to the IESO-controlled grid. Opportunities for connecting renewable generation in northwestern Ontario can be assessed during more advanced stages of transmission planning work, when Ontario will be better able to consider project proposals in the context of broader system planning. This includes consideration of Ontario electricity demand and cost-effectiveness of supply options, as well as relevant procurement targets and programs at the time.

In the near term, transmission connection is the more economic of the diesel alternatives assessed. In communities that are not currently economic to connect, renewable generation can help to lower diesel consumption. As is discussed further in section 8, options for adopting renewable power systems in these communities should be investigated.

5.0 PRINCIPLES FOR COST ALLOCATION

As a number of sections of this report have demonstrated, a variety of stakeholders stand to benefit from the connection of remote First Nation communities in northwest Ontario to the provincial electricity grid. Section 2 showed that the federal government, provincial government, and Ontario electricity ratepayers currently pay about 90% of the total cost of electricity service in remote communities. Section 4 established that there is a strong business case for the transmission connection of 20 remote First Nation communities given the significant cost savings from reduced diesel expenditures expected over the forty year planning horizon of this project.

The benefits of grid-connected electricity service in remote communities will accrue to the parties who fund their electricity systems – most notably, the federal government, Ontario electricity customers, and the provincial government. Benefits will not be limited to avoided diesel generation costs, and will change over time. For example, the need for capital upgrades to the existing diesel generating infrastructure in coming years means that, in the absence of any transmission connection, federal government contributions to electricity service in remote communities will need to increase to levels substantially higher than shown in Section 2. Likewise, increases to contributions will also result from the increasing cost of diesel fuel and its transportation to remote communities.

In addition to these direct financial benefits, the project also affords numerous additional economic, social, developmental and environmental benefits through such merits as enabling load growth, increasing reliability, reducing environmental impacts and risks, and unlocking economic growth.

Not all of these benefits accrue to each party equally. Table 15 summarizes the main benefits and beneficiaries of the transmission connection project.

Table 15: Beneficiaries of Remote Community and Mining Connections

Beneficiaries	Source of Benefit
Federal Government	• Reduced operating subsidies to IPAs • Reduced diesel system expansion costs • Reduced Standard A rates • Reduced environmental impact and potential future environmental remediation liabilities • Cleaner air and reduced greenhouse gas emissions • Benefits of regional economic development • Reduced social costs within First Nation communities • Potential to reduce costs for all season road development
Province of Ontario • Ontario electricity customers	• RRRP subsidy savings
• Government	• Reduced Standard A rates • Cleaner air and reduced greenhouse gas emissions

	• Benefits of regional economic development
Industrial Electricity Customers	• Avoided diesel generation costs for remote mining facilities and associated liabilities • Opportunity to cost share with remote communities
Remote Community Customers	• Reduced infrastructure barriers to growth • Stabilized retail and commercial rates • Increased economic development opportunities • Reduced environmental impact • Improved reliability of electricity supply • Improved social and living conditions for residents

Substantial near term investment will be required in order to realize the long term benefits of reducing diesel use for electricity generation. To ensure a successful project implementation, these investments should come from those who stand to benefit, and should reflect the expected changes in those benefits over time. In order to implement a plan for transmission connection, the federal government, the province (representing both the rate base and tax base), the remote communities and any participating industrial customers will need to come to agreement on the extent of costs to be shared and the allocation of those costs among them.

Discussions toward such an agreement may find a starting point in the notion that costs ought to be borne proportionally to use and to benefit -- a principle already embedded in Ontario's electricity sector in its transmission system code and in regulation under the Electricity Act. However, it is clear that, given the complexity of the project and the diversity of beneficiaries, extensive and early engagement among the negotiating parties will be essential to achieve a firm agreement on cost sharing and allocation. This agreement will also be instrumental for the planning certainty needed to move the project forward in a timely manner. Table 16 below illustrates the core principles which parties could mutually recognize and adopt as a basis for their discussions to help ensure successful outcomes.

Table 16: Principles for Remote Community Connection Cost Sharing

- All parties should acknowledge that, given the current subsidization of remote community energy costs, the feasibility of the transmission connection project is dependent on both federal and provincial financial participation (including the Ontario electricity rate base).
- Project costs should be allocated among the negotiating parties proportionally to the benefits accruing to each.
- Benefits include not only the avoided costs of diesel generation, but also additional benefits such as those relating to the environment and economic development.
- Contributions to project costs should take into account the capital costs as well as the ongoing operating costs required for remote community connections and operation.
- Project costs include investments in the Line to Pickle Lake and necessary system upgrades at Red Lake, both of which are prerequisites for remote community connection.
- Private interests such as mining operations that jointly use some of the project's transmission assets should pay their proportion of project costs as outlined in the Ontario Energy Board's codes.
- Once grid connected, the total rates charged to remote community residents should remain generally in-line with rates charged to other residents across Ontario.
- Project costs and benefits accruing to each party should be determined through a transparent process involving the sharing of cost data to make a fair determination of cost sharing responsibilities.

6.0 PLAN FOR REMOTE COMMUNITIES IDENTIFIED AS UNECONOMIC TO CONNECT AT THIS TIME

As noted in section 4.1, five remote First Nation communities have been identified as uneconomic to connect at this time: Whitesand, Kiashke Zaaging Anishinaabek (also known as Gull Bay), Marten Falls, Fort Severn and Peawanuk. The OPA will work with each of these communities on an individual basis to identify their unique and individual needs and help them to develop solutions that will assist in cost effectively reducing diesel consumption in their communities.

The OPA will seek to work directly with community members to assess how future energy needs can be met in these five communities. The OPA will support community meetings and planning sessions, as well as collecting, presenting and processing baseline information required to proceed with integrated resource planning (“IRP”). Options assessed within the IRP process include conservation and renewable micro-generation projects.

It is important to note that preliminary studies indicate that maintaining a reliable electrical supply source to these five communities will require retaining diesel generation as the primary supply source. Wind and solar resources are intermittent in nature, and their operating profiles do not match well with community demand needs. However, the analysis indicates that properly sized renewable generation, coupled with battery storage, can be used to economically displace some diesel generation.

Table 17 provides the results of a preliminary cost benefit analysis, which shows that the cost of integrating renewable generation and storage with existing diesel systems is likely to be more cost effective than continuing to operate solely with diesel generation. The analysis shown in Table 17 found that the resource combinations of wind/diesel and hydro/diesel, are the most cost effective and provide the greatest reduction in diesel consumption. There would also be environmental advantages to making this change, which are not captured in this preliminary cost benefit analysis below.

Table 17: Preliminary Analysis of Diesel Integrated Renewable Generation

Community	Wind Capacity (kW)	Storage Capacity (kW)	Energy Cost ($/KWh)	Energy Supplied by Diesel
Fort Severn	2,200	300	0.60	44%
Peawanuk	1,400	100	0.61	43%
Whitesand/Armstrong	2,000	300	0.63	59%
Kiashke Zaaging Anishinaabek	600	100	0.63	58%
	Hydro Capacity (kW)	**Firm Capacity (kW)**	**Energy Cost ($/KWh)**	**Energy Supplied by Diesel**
Marten falls	2,000	400	0.38	36%

Source: OPA

There are a number of remote First Nation communities with small renewable generation units currently operating that help to reduce diesel consumption:

- Kasabonika Lake First Nation (wind turbines)
- Deer Lake First Nation (Shoulder Blade Falls GS)
- Kitchenuhmaykoosib Inninuwug First Nation (wind turbines)

Through the operating history of these projects, a significant amount of experience has been gained regarding the technical requirements, performance and community participation in renewable energy projects in remote communities. These learnings, along with those of similar successful projects in Canada and other countries, should be leveraged to ensure best practices are adopted in future projects.

The OPA is also aware that Whitesand First Nation is investigating development of a bio-mass based co-generation unit. The unit is planned to use local biomass resources and waste from its host saw mill to generate electricity that could substantially offset diesel use at the local diesel generation station in Armstrong. Progress associated with this project will be monitored and included in future analysis depending on its economic feasibility. The project is expected to create jobs and economic development for the community of Whitesand First Nation, which may contribute to load growth, and ultimately affect the economics of transmission connection.

It should be noted that the unique opportunities and resources available in each community will determine the solution that will best fit a particular community's electricity needs. Whitesand First Nation's biomass proposal might be effective given the resource availability, road access, connections to the non-First Nation communities of Collins and Armstrong, and a need for power supply driven by economic development activities being undertaken in the region. However, similar opportunities may not be available or effective for other remote First Nation communities. Each community will need a specific study tailored to its unique needs and opportunities.

7.0 CONNECTION PLAN FOR THE 20 REMOTE COMMUNITIES

The practical development of a staged connection plan must account for the geographic relationship between available supply points (Red Lake and Pickle Lake) and the various communities, the long-term load levels to be served as well as environmental challenges and land use constraints. This plan envisions line development being implemented in stages starting from Red Lake and Pickle Lake and moving north. As a transmission backbone is constructed, transformer stations and distribution feeders are assumed to be constructed to connect communities in the area. This allows for communities to be connected as transmission development progresses north along proposed corridors to the various communities.

The OPA in consultation with the Committee has considered and assessed a number of routing and line configuration options previously studied by Indian and Northern Affairs Canada (2001), the Waterpower Working Group (2009), the Central Corridor Energy Group. This plans leverages many of the same principles employed in those previous studies, while improving the balance between cost, reliability and operability.

The connection options identified in this plan have attempted to satisfy and balance the following criteria:

- Feasibility, the ability to meet long-term electricity demand growth while meeting relevant technical criteria;
- Reliability, meeting the requirements of the Ontario Resource and Transmission Assessment Criteria (“ORTAC”);
- Cost;

- Flexibility, including consideration of connecting future renewable generation sites and potential commercial/industrial customers that enhance economic opportunities;
- Environmental Performance; and
- Societal Acceptance.

7.1 Connection Configuration Options

The OPA has considered and assessed both radial and interconnected line configurations to connect the communities. This assessment concluded that a radial system will provide the most long-term value, while meeting system performance requirements. It should also be noted that the IESO's Ontario Resource and Transmission Assessment Criteria (Section 7.1 Load Security Criteria), allows for loads up to 150 MW to be served by single circuit radial lines.

The OPA has investigated the technical and economic feasibility of an interconnected system to connect the 20 remote communities north of Red Lake and Pickle Lake. The assessment identified a number of issues that make such an interconnection technically and economically infeasible:

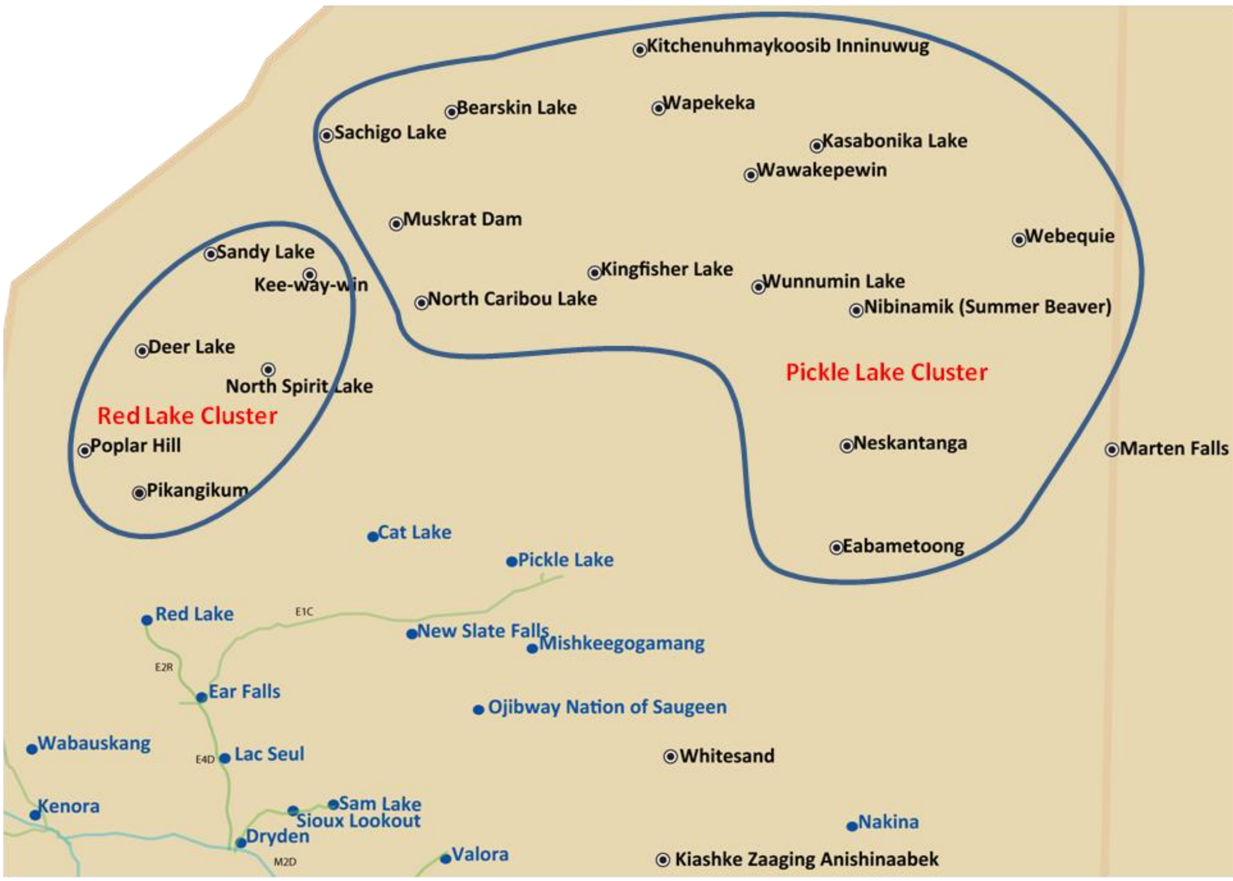
- Neither Red Lake nor Pickle Lake are technically capable of supplying a majority of the communities should supply from one of these sources not be available;
- Reliability is likely to be lower, as the interconnected system would be more exposed to weather systems and related outages;
- Higher cost, as more high voltage transmission line would be required relative to a radial system, and there would be a much larger need for voltage control devices; and
- Fewer cost economies from sharing centrally located transmission stations among communities.

To maintain reliability in the remote communities this plan recommends that the diesel fleet currently operating in the communities be maintained in full operable condition, so that it will be available to supply the communities during planned and unplanned transmission outages. It is expected that the current installed capacity of the fleet would be sufficient to supply local community needs in emergency situations until at least 2030. This approach should ensure supply availability under most contingencies and has been used successfully by Five Nations Energy Inc. in supplying their communities for almost 10 years.

7.2 Geographic Configuration of the 20 Communities

The 20 communities are arranged in two natural clusters north of Red Lake and around Pickle Lake based on geography and technical challenges as shown in Figure 14 below.

Figure 14: Red Lake and Pickle Lake Remote Clusters



Source: OPA

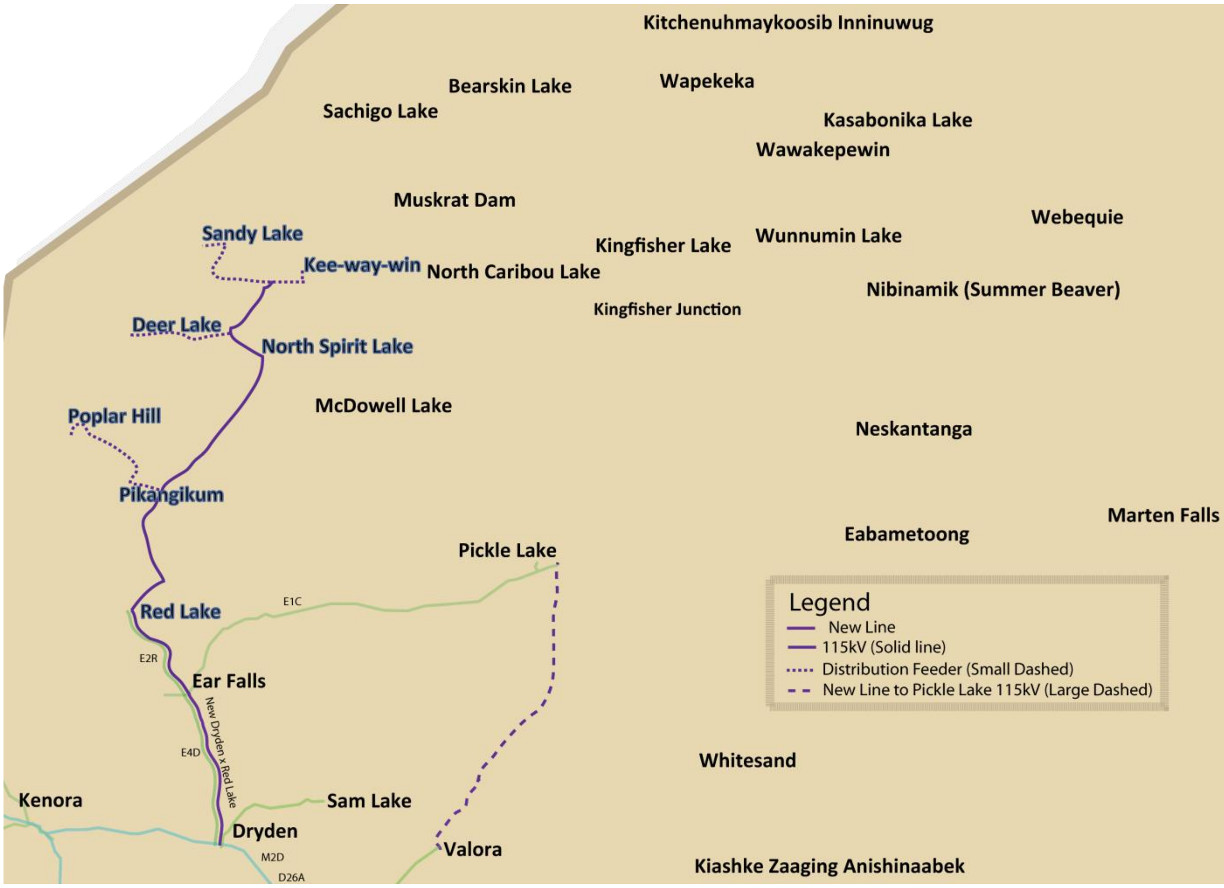
Six communities are located along a corridor north of the Town of Red Lake. These communities are Pikangikum First Nation, Poplar Hill First Nation, North Spirit Lake First Nation, Deer Lake First Nation, Sandy Lake First Nation, and Keewaywin First Nation. These communities have an existing load of 6 MW, which is forecast to grow to 13 MW by 2033 and 29 MW by 2053.

North of Pickle Lake, 14 communities form a 450 km arc extending from Sachigo Lake First Nation (300 km northwest of Pickle Lake) to Eabametoong First Nation (160 km east of Pickle Lake). These communities are Eabametoong First Nation, Neskantaga First Nation, Webequie First Nation, Nibinamik First Nation, Wunnumin Lake First Nation, Kingfisher Lake First Nation, Wawakapewin First Nation, Kasabonika Lake First Nation, Wapekeka First Nation, Kitchenuhmaykoosib Inninuwug First Nation, Bearskin Lake First Nation, Sachigo Lake First Nation, Muskrat Dam First Nation, and North Caribou Lake First Nation. These communities have an existing load of 9.5 MW which is forecast to grow to about 20 MW by 2033 and 44 MW by 2053.

It is expected that each radial line system from Red Lake and Pickle Lake can be developed independently allowing the opportunity for multiple lines to be developed and built at the same time. This may reduce the overall time to completion. The OPA has developed a preferred connection option for the Red Lake Cluster (Figure 15), while there are two connection configurations for the Pickle Lake Cluster (Figure 16 and Figure 17). The Pickle Lake Cluster configurations are differentiated by whether or not the Ring of Fire is to be supplied from Pickle Lake. In Scenario A, 4 remote communities are shown to connect to a proposed new line from Pickle Lake to the Ring of Fire. If the Ring of Fire is supplied from Pickle Lake, then a new 230 kV supply at Pickle Lake would be required. In Scenario B, the four communities are connected using two separate lines. These line connection configurations were developed in consideration of the planning criteria mentioned above.

7.3 Red Lake Radial System

Figure 15: Connection Configuration for Red Lake Remote Cluster



Source: OPA

The supply option from Red Lake is designed to serve the six communities north of Red Lake with a new 115 kV single-circuit line. This new 115 kV line would extend the existing transmission system at Red Lake TS north toward Pikangikum First Nation, then to North Spirit Lake First Nation, and would terminate at a new TS south east of Sandy Lake First Nation. To supply these communities step-down transformer stations ("TS") are planned close to Pikangikum First Nation, North Spirit Lake First Nation and a third at the end of the line south east of Sandy Lake First Nation. Each community is assumed to be connected to the closest TS with a distribution feeder (44 kV or 25 kV). Pikangikum First Nation, and Poplar Hill First Nation would be supplied by the first TS. Deer Lake First Nation and North Spirit Lake First Nation would be supplied by the second TS while Sandy Lake First Nation and Keewaywin First Nation would be supplied by the station south of Sandy Lake.

The project could begin construction once the supply reinforcements for Red Lake are completed (current expectation is for Red Lake to be reinforced by 2016 or 2017). It is expected that construction and commissioning of this project would take three to four years.

7.4 Pickle Lake Cluster

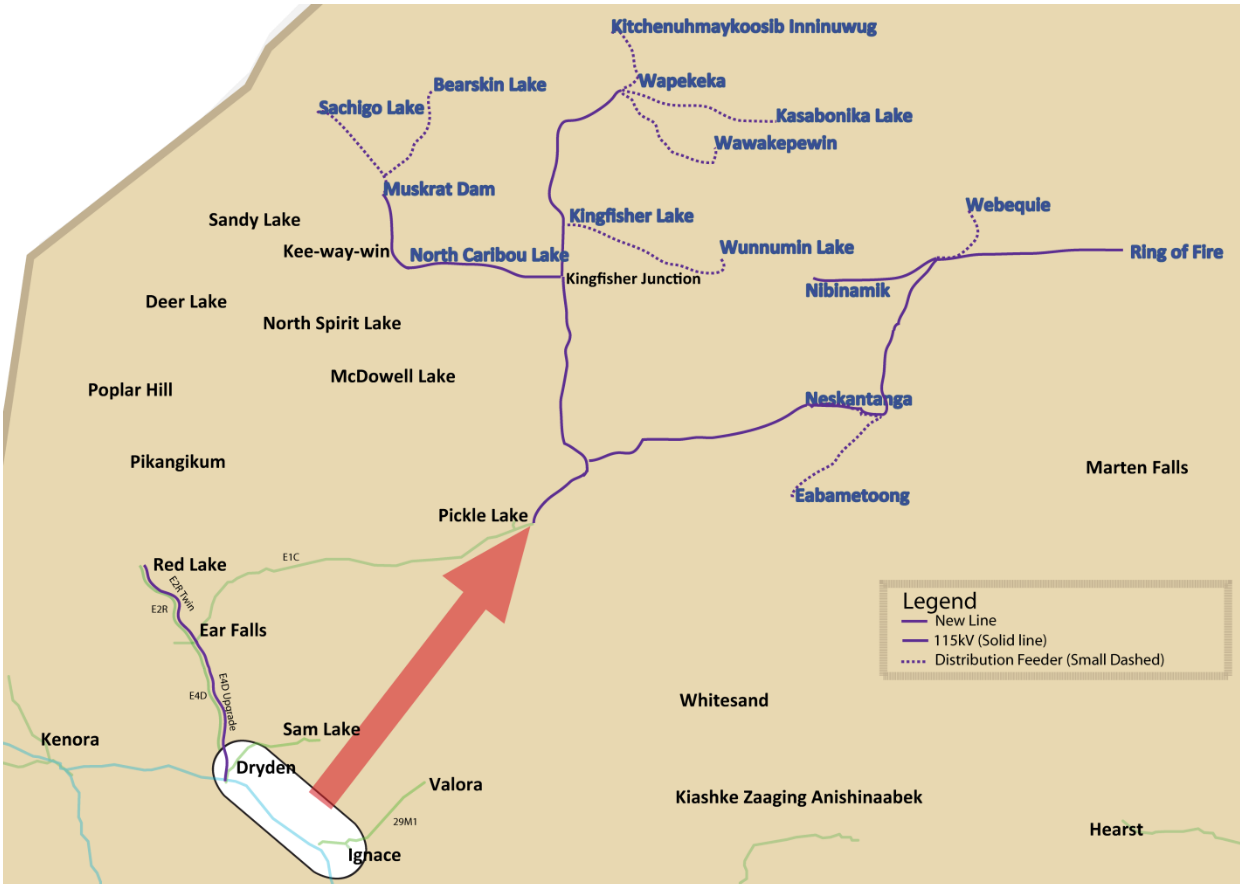
As mentioned earlier, scenarios for the Pickle Lake Cluster are differentiated by a new line from Pickle Lake to the Ring of Fire being developed and the 4 remote communities that are situated along the route being able to connect to the line.

A radial system to supply the Pickle Lake Cluster may be developed in four to five sections. The project could begin construction as soon as the new line reinforcement to Pickle Lake is completed (expected to be completed in 2015). It is expected that construction and commissioning of all of the sections could take about five years.

7.4.1 Pickle Lake Cluster Configuration for Scenario A (with Ring of Fire Supply Line)

With a 230 kV supply available at Pickle Lake, the Pickle Lake cluster of remote communities and up to 30 MW of future load at the Ring of Fire can be supplied from Pickle Lake. This configuration optimizes the connection arrangement of the 4 remote communities between Pickle Lake and the Ring of Fire by sharing the capacity and cost of their connection with customers to be served at the Ring of Fire. Figure 16 shows how connection of this cluster of 14 remote communities (10 north of Pickle Lake and 4 east of Pickle Lake) could be configured.

Figure 16: Pickle Lake Cluster Configuration for Scenario A



Source: OPA

The line to supply the Ring of Fire from Pickle Lake may be able to follow a proposed transportation/utility corridor between Pickle Lake and the Ring of Fire. A transmission line following this potential transportation/utility corridor could more economically connect the 4 remote communities in the area (Eabametoong, Neskantaga, Nibinamik, and Webequie), compared to Scenario B which is discussed below. There are also a number of potential hydro sites in the area, which range in potential size up to about 30 MW. These sites could be developed at a larger scale and thus be more economic to develop if transmission is available in the area. The future development of new hydro projects in northwest Ontario would be subject to a separate decision process and is not considered in this connection plan. However, generation in this area could provide incremental load serving capacity to the area, by providing both energy and reactive power locally. Developing these sites may also reduce the need for dedicated equipment that might otherwise be needed to maintain voltage and stabilize the system.

Pickle Lake to Kingfisher Junction

A new 180 km, 115 kV single-circuit line is expected to extend from Pickle Lake to a new station that is expected to be built about 30 km south of Kingfisher Lake First Nation following existing all-season and winter roads where possible. The new station is assumed to have switching facilities to supply the following lines:

- Kingfisher Junction to Muskrat Dam Line; and
- Kingfisher Junction to Wapekeka Line.

To maintain system voltage stability on these lines reactive compensation devices (series capacitors or an SVC) would need to be placed at this station where they would be able to manage voltage centrally for all of the other radial lines.

Kingfisher Junction to Muskrat Dam Line

A new 115 kV single-circuit line from Kingfisher Junction is planned to extend 160 km northwest from Kingfisher Jct. to Muskrat Dam First Nation on a route passing North Caribou Lake First Nation. New TS are planned at North Caribou Lake First Nation and at Muskrat Dam First Nation. From the new Muskrat Dam TS, two distribution feeders would run north. One feeder would connect Sachigo Lake First Nation and the other to connect Bearskin Lake First Nation. This feeder is capable of connecting potential hydro generation sites along the Severn river system that First Nation in the area have identified as having high potential for development.

Kingfisher Junction to Wapekeka Line

A new 145 km, 115 kV single-circuit line is planned to extend from Kingfisher Junction to Wapekeka First Nation. A new TS could be located at Kingfisher Lake First Nation and at Wapekeka First Nation. Kingfisher TS would supply Kingfisher Lake First Nation and Wunnumin Lake First Nation through and new distribution feeder. Distribution feeders from Wapekeka TS would supply Kasabonika Lake First Nation, Wawakapewin First Nation and Kitchenuhmaykoosib Inninuwug First Nation.

Pickle Lake to the Ring of Fire via Webequie Junction

To supply industrial customers at the Ring of Fire as well as Eabametoong First Nation, Neskantaga First Nation, Nibinamik First Nation, and Webequie First Nation a new 370 km, single-circuit 115 kV transmission line would be built from Pickle Lake to the McFaulds Lake area. Routing would be optimized to minimize the connection costs for these First Nation, while also following a potential transportation corridor currently being planned from the McFaulds Lake area to Pickle Lake via Webequie. There are both cost and line performance synergies created by connecting these four communities to a line supplying the Ring of Fire. Wunnumin Lake First Nation can also be connected more economically to Kingfisher TS by a distribution feeder, than in the alternative in Scenario B.

The OPA's load forecast for Ring of Fire anticipates about 25 MW by 2020, growing to 35 MW by 2030. There is a possibility that demand could grow further to about 60 MW by the mid 2030s. The OPA plans to monitor growth in the area over the medium and long term and propose additional future plans as needed.

A single-circuit 115 kV line from Pickle Lake to the Ring of Fire would have sufficient capacity to serve the forecast load of 5 MW in the four First Nation communities and approximately 35 MW of industrial load at the Ring of Fire. There are upgrades that could be done to expand this line's capacity somewhat. However, if more than 35 MW of load is expected to be served in the Ring of Fire area, then either an additional 115 kV line or an upgrade of the first 115 kV line to 230 kV operation would be required.

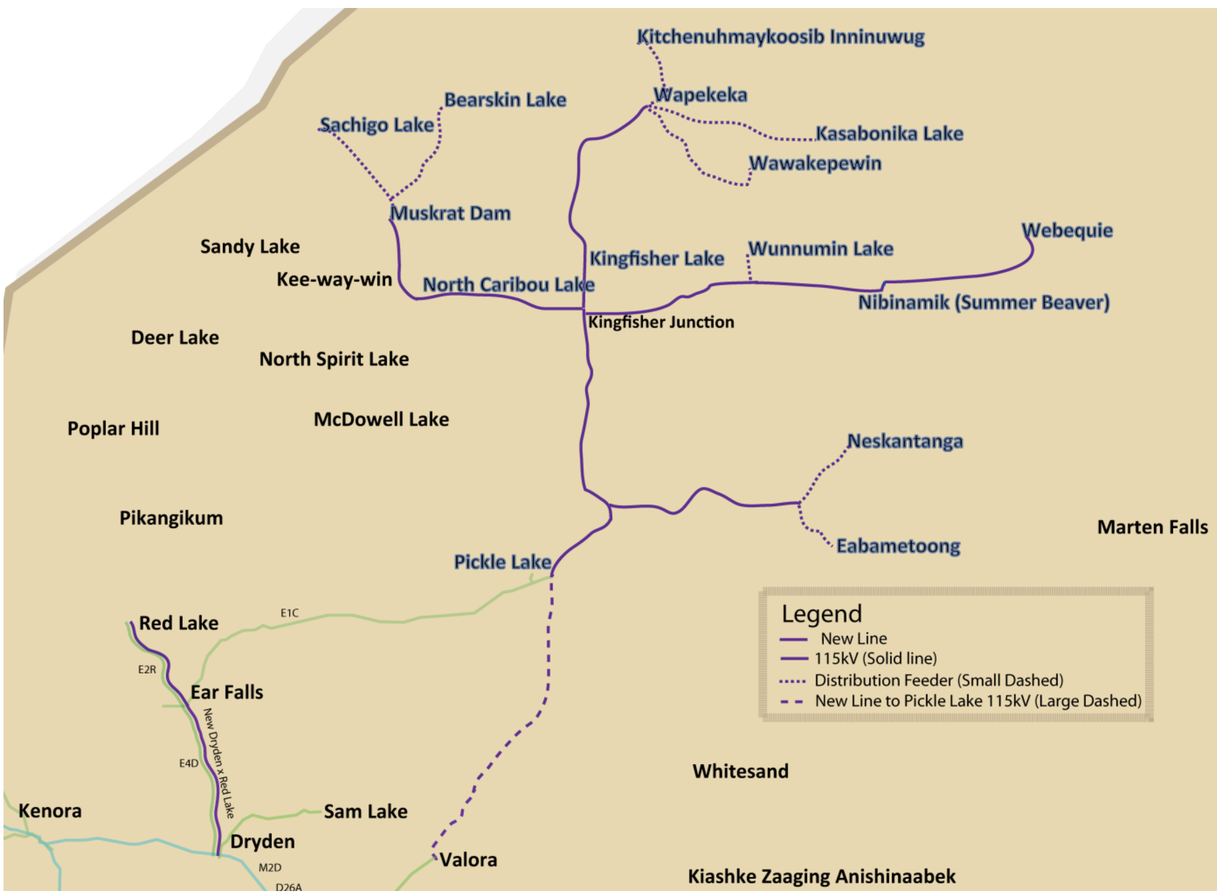
The current mine development timelines suggest that a transmission line to the Ring of Fire could be required as early as 2016 , which would require co-development of this facility with a new 230 kV Supply to Pickle Lake.

A cost sharing arrangement based on proportional use (in the long-term) would suggest that approximately 15% of the cost of the line (based on 5 MW of load) could be allocated to the remote community connection plan, while the mining customers at the Ring of Fire are assumed to contribute approximately 85%. The remote connection plan would also be responsible for the cost of the connection facilities (transmission stations, distribution lines, and distribution stations) where required to connect the 4 communities to the transmission line.

7.4.2 Pickle Lake Cluster Configuration for Scenario B (without Ring of Fire Supply Line)

This configuration for connecting the 14 communities north and east of Pickle Lake does not include or assume any supply to the Ring of Fire from Pickle Lake. As such Eabametoong and Neskantaga and the three communities east of Kingfisher Jct. are shown connected in a different configuration which requires incremental transmission line which would not be shared with industrial customers. The resulting cost to connect these communities in this configuration is expected to be higher than in Scenario A. Figure 17 shows this alternate connection configuration.

Figure 17: Pickle Lake Cluster Configuration for Scenario B



Source: OPA

Without the additional capacity required for the Ring of Fire, both 115 kV and 230 kV reinforcement of Pickle Lake would be sufficient to meet the anticipated demand growth in the Pickle Lake area including connecting and supplying the forecast load growth of the remote communities north of Pickle Lake until 2033. It is expected that a 115 kV Supply to Pickle Lake would reach its capacity to serve load around 2035 based on long-term growth expectations for loads that would be connected to it. Serving expected load levels after 2035 would require a new transmission line. A 115 kV line would also not have sufficient capability to supply resource developments at the Ring of Fire. However, there is the possibility that existing or future customers supplied from Pickle Lake could reduce their load on these facilities and free up capacity before 2035 which could be used to supply the remote community load growth after 2035. There is also potential for new mines or remote community load growth to increase demand on Pickle Lake beyond what the forecast, which would lead to supply limitations in the area before 2035.

The lines from Pickle Lake to Kingfisher Junction and Kingfisher Junction to Muskrat Dam are the same in Scenario B as in Scenario A and thus their description is not repeated.

Kingfisher Junction to Wapekeka LineA new 145 km, 115 kV single-circuit line is planned to extend from Kingfisher Junction to Wapekeka First Nation. New TS could be located at Kingfisher Lake First Nation and at Wapekeka First Nation. Kingfisher TS would supply Kingfisher Lake First Nation and Wunnumin Lake First Nation through and new distribution feeder. Distribution feeders from Wapekeka TS would supply Kasabonika First Nation, Wawakapewin First Nation and Kitchenuhmaykoosib Inninuwug First Nation.

Kingfisher Junction to Webequie Line

A new 195 km 115 kV single-circuit line from Kingfisher Junction to Webequie First Nation passing near Wunnumin Lake First Nation and Nibinamik First Nation is planned to terminate at a new TS near Webequie First Nation. New TS are also planned to be built near Wunnumin Lake First Nation, and Nibinamik First Nation to supply those communities.

Eabametoong - Neskantaga Line

A new 120 km 115 kV single-circuit line is planned to be tapped off of the Pickle Lake to Kingfisher Junction line at a point approximately 55 km northeast of Pickle Lake. This new line would run east to a point between Eabametoong First Nation and Neskantaga First Nation where it would terminate at a new TS. From this new TS, feeders would extend to Neskantaga First Nation and Eabametoong First Nation. The feeders to both communities would be between 70 km and 100 km.

Table 18 summarizes the line distances and costs for each of the line projects under both scenarios A and B. As noted elsewhere, each of these scenarios is dependent on upgrades to the existing system in the Red Lake and Pickle Lake areas.

Table 18: Summary of Remote Community Connection Lines

	Transmission Line (km)	Distribution Line (km)	Years to Construct	Cost* ($M)	Communties Connected
Scenario A					
Red Lake Cluster	257	237	3	275	6
Pickle Lake to Kingfisher Jct	181	0	2	115	0
Kingfisher to Muskrat Dam	157	154	3	160	4
Kingfisher to Wapakeka	110	217	3	150	6
Ring of Fire Line	320	215	3	105	4
Total - Scenario A	**1025**	**823**	**5-6**	**805**	**20**
Scenario B					
Red Lake Cluster	257	237	3	275	6
Pickle Lake to Kingfisher Jct	181	0	2	115	0
Kingfisher to Muskrat Dam	157	154	3	160	4
Kingfisher to Wapakeka	110	165	3	125	5
Kingfisher to Webequie and Pickle Lake to Neskantaga/Eabametoong	299	155	3	255	5
Total - Scenario B	**1004**	**711**	**5-6**	**930**	**20**

* Cost represents only the portion of the proposed transmission facilities owing to the connection of remote communities. The Line to the Ring of Fire will cost about $300M including remote community connections, of this the remote community connection portion is estimated to be $105M.

Source: OPA

8.0 INTERIM SOLUTIONS FOR ALL NORTHWEST ONTARIO REMOTE FIRST NATION COMMUNITIES

The OPA will work with the remote communities beyond Pickle Lake through the Committee and with others that are not included in this connection plan through a process to develop interim solutions to cost effectively reduce their reliance on diesel generation.

The Feed-in-Tariff Program Two Year Review Report, released in March of 2012, stated that the government should explore potential partnership opportunities for renewable energy projects in off-grid remote Aboriginal communities. Partnerships between and among entities such as private sector renewable energy companies, interested remote communities and the parties who currently fund their energy infrastructure could enable participating communities to come up with innovative solutions to reduce some of their use of high-cost, high-emissions diesel generation. Evaluation of such interim solutions should include consideration for the sizes and scales of deployments appropriate to ensure the value of the long-term transmission solution.

9.0 DEVELOPMENT WORK REQUIRED AND TIMELINES

The following tasks will be necessary to develop the lines in this plan:

- Identification of a transmitter for project development;
- Detailed technical system studies;
- Route and site identification and assessment;
- Preliminary engineering;
- Preparation and submission of EA Terms of Reference;
- EA studies and field work, EA approval; and
- Preparation and submission of Leave to Construct application.

Delays in commencing and/or completing any of the tasks will lead to delays in the timing of some or all of the communities being connected. An additional factor not discussed in detail in this plan is the process and framework for arranging financing for these projects. Substantial near term investment will be required in order to realize the long term benefits of reducing diesel use for electricity generation. To ensure successful project implementation, these investments should be made by the parties that stand to benefit, and should reflect the expected changes in those benefits over time. As discussed in Section 5, in order to implement a plan for transmission connection, the federal government, the province (representing both the rate base and tax base), the remote communities included in this plan for connection and any participating industrial customers will need to come to agreement on the extent of costs to be shared and the allocation of those costs among them.

The Far North Act, being implemented by Ontario Ministry of Natural Resources, requires that all communities conduct land use planning prior to commencing the development of new transmission facilities; thus, the development timelines identified in this plan to connect remote communities may be affected by the progress communities make in completing their land use plans.