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2.0 NEED AND ALTERNATIVES

2.1 INTRODUCTION

Manitoba Hydro is under a statutory obligation to ensure the availability of a supply of power adequate to meet the needs of the Province. Without improvement, Manitoba's system is extremely vulnerable to weather or other emergency events which could interrupt the use of either the existing Bipoles I and II high voltage direct current (HVdc) lines located on the Interlake corridor or the single southern converter station (Dorsey). This chapter describes the urgent need to ensure the reliability and security of Manitoba's power supply and reviews the various alternatives for meeting that need.

In arriving at the conclusion that the Bipole III Project is the best alternative for meeting the province's reliability requirements, the chapter considers and analyzes the following questions:

- Why is the Project needed and what load serving requirements will it have to meet in order to sufficiently enhance system reliability?
- What options aside from new north-south transmission are available for addressing system reliability and what criteria were used to evaluate such options?
- Given that the construction of new north-south transmission has been determined to be the best reliability option, what alternative means of transmission can be built in order to carry power from the north to the south?

The chapter identifies that the best solution to meet the reliability needs of the Province is a new overhead north-south HVdc transmission line. Alternative routes for the transmission line are considered in Chapter 7.

2.2 NEED FOR AND SIZE OF THE PROJECT

2.2.1 Overview of Manitoba Hydro System Reliability Issues

Manitoba is heavily reliant on hydroelectricity, approximately 70%[1] of which is generated in plants in northern Manitoba in the form of alternating current (ac). This power is fed into the northern ac transmission system which is known as the Northern Collector System. In order to supply southern Manitoba today, power in the Northern Collector System must be converted from ac to HVdc for transmission over the exceptionally long distances to southern Manitoba, and then re-converted to ac form in southern Manitoba for transmission to customers via the Southern ac System.

At present, the overall Manitoba Hydro system depends on two converter stations in the north (Radisson and Henday), two HVdc lines (Bipoles I and II) running south along the same Interlake corridor, and the single Dorsey converter station in the south. The single Interlake corridor carries about 70% of Manitoba's entire generation supply. Manitoba is the only system in the world with such a concentration (of percentage) of supply along one corridor and in one converter station.

Manitoba's HVdc system is extremely vulnerable to weather or other events which could damage the Bipole I and II lines in the Interlake Corridor or Dorsey Station. The potential consequences of such an outage of the existing HVdc transmission system are exacerbated by the very long estimated repair times. Wide front windstorm, fire, or tornado damage at Dorsey Station could cause an outage that shuts down the HVdc system for up to three years because of the time required to repair or replace equipment of such complexity. The duration of a similar outage of the Bipoles I and II lines, although not as severe and dire as a failure at Dorsey Station, could still easily cause an outage of six to eight weeks.

In the event of an extended HVdc outage, supply would be restricted to the generation connected to the ac system and the possible imports on the ac interconnections with the United States and neighbouring provinces. Such a restricted supply of power would be significantly inadequate to meet provincial demand, particularly in the winter, and could necessitate rotating blackouts for months. The potential shortfall has been growing steadily over the years, as increased demands for power from new and existing customers have increased the system load requirement.

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[1] The Northern Collector System generation totals 3570 MW, which is 70.9% of the total Manitoba Hydro hydroelectric generation of 5033 MW.

The potential effects of such an event present a risk that is unacceptable to Manitoba customers, particularly in the very cold months when the loss of power for extended periods could have serious effects on health, safety and security. The loss of Dorsey Station for up to three years could have a disastrous impact to the province and its economy.

The extensive rotating blackouts would leave affected neighbourhoods without power for extended stretches of time on a daily basis meaning that day to day requirements such as lighting, refrigeration, heating/cooling would be unavailable on a rotating schedule. Similarly, businesses would also be without power to operate their facilities forcing them to close during such outages, and causing business disruptions.

The types of events that could occur to put system reliability at risk in Manitoba include forest fires, fire at a converter station, weather events such as downburst/wide front winds, tornados and ice storms. The probability and potential duration associated with these potential catastrophic events is discussed in the following section.

2.2.2 Probability and Durations of a Catastrophic HVdc Outage

The potential of catastrophic failure of either the Bipole I and II lines or Dorsey Station due to fire and extreme weather events has been evaluated by Manitoba Hydro, in consultation with experts in the field.

Studies (Teshmont 2001) have shown that with respect to Dorsey Station, there is a 1 in 29 year probability of outage due to fire and a 1 in 200 year probability of outage due to wide front winds. While mitigation measures have been put in place, which partially address fire vulnerability at Dorsey, there is little that can reasonably be done to mitigate vulnerability to wind and other weather events. The same studies (Teshmont 2001) revealed that the probability of the loss of the Interlake corridor is 1 in 17 years from a tornado, 1 in 50 years from icing and 1 in 250 years from wide front winds.

Several “near-miss” experiences in Manitoba have highlighted the need for a major system reliability enhancement. Two examples are outlined below, each of which could easily have caused greater damage and led to more severe consequences.

Manitoba Hydro Wind Event, September 1996

On September 5, 1996 a downburst wind event caused the failure of 19 Bipole I and II transmission towers just two km north of Dorsey Station. Had this event occurred closer to Dorsey Station, it could have also taken down the Dorsey-Forbes 500 kV interconnection which would have in turn reduced the amount of power that could be imported from the United States. It took over four days to restore one HVdc line. Bipole I and II converters were then operated on this one line until the second dc line was repaired.

Photo 2.2-1: Damaged Towers of (TWG #1991) Bipole I and II Lines by Downburst Winds in 1996

Due to the time of year (September), the load was relatively low. Manitoba Hydro managed to serve the entire load during this event by relying heavily on arranged imports of up to 985 MW of power from the USA and neighbouring provinces, as well as by appealing to the public to reduce consumption. Had the event occurred just a month or two later in the year when load levels would have been higher, rotating blackouts would have been unavoidable.

Elie Tornado, June 2007

On June 22, 2007, a level 5 tornado (the strongest confirmed tornado in Canadian history) flattened buildings and the electrical infrastructure in the town of Elie just west of Winnipeg. Extensive damage caused by the tornado left thousands of customers without electricity until service was restored two days later. Damage to towns and communities from a separate storm system farther west was more severe, leaving many more thousands of customers without power for even greater periods.

Photo 2.2-2: Elie F5 Tornado and the Aftermath Damage

The Elie tornado was on the ground for about 35 minutes, and traveled a distance of approximately 5.5 kilometres (km). Damage occurred throughout a swath of land that reached widths of up to 300 meters. At their most intense, the tornado wind speeds were estimated to have reached between 420 and 510 km/h. An entire two-story home was swept off its foundation and tossed 75 feet in the air before rotating around the tornado and being obliterated.

Dorsey station is only 30 km north of Elie. A tornado of this or even lesser magnitude at Dorsey would have leveled the station, causing the kind of catastrophic failure discussed throughout this chapter.

2.2.3 Potential Load Shortfall and Required Size for Reliability Project

The chart set out below in Figure 2.2-1 depicts the available power supply and peak load in the event of loss of the Bipoles I and II transmission lines. With Wuskwatim generation in service, in the event of a catastrophic outage, the 2011/2012 system shortfall at winter peak is about 1400 MW, and will increase steadily with the growth in load to approximately 1500 MW by 2017 and 2000 MW by 2025, even after the 300 MW improvement associated with Riel sectionalization. The supply which would be available under such outage conditions is based on existing thermal generating capacity, generation connected to the ac system and the ability to import 900 MW of power from outside of Manitoba. The 1500 MW shortfall would be equivalent to the power demand of over 300,000 average residences based on an average peak demand of 5 kVA/household.

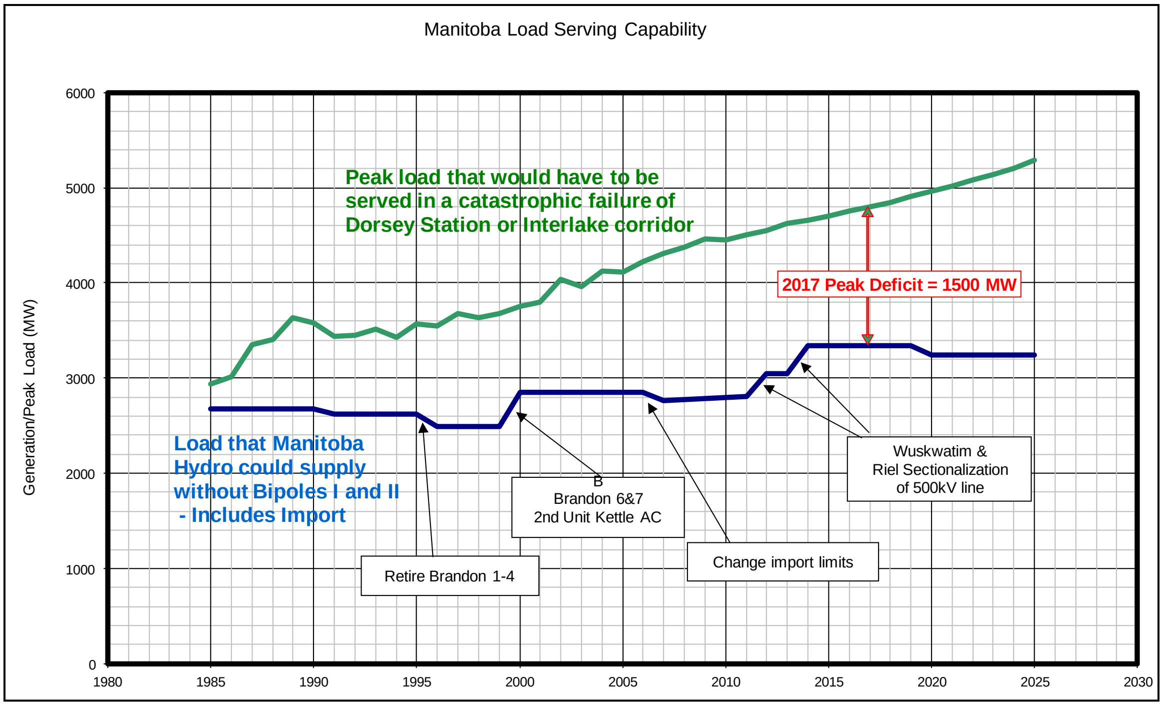

Figure 2.2-1: Load Serving Capability without Bipoles I & II

The deficit has been growing despite the various system improvements that have been made over the years, demonstrating the need for a reliability initiative that would address the deficit in full for a reasonable time frame in to the future.

Recognizing that the system is not always operating at peak load requirement, additional data must be considered to evaluate the consequences on a broader basis. Given that loads vary with both time of year and time of day, these variables must be taken into account when evaluating the loss of transmission capacity. Figure 2.2-2 depicts this analysis showing that in 2017/18, if Bipoles I and II were unavailable, Manitoba Hydro would be unable to meet provincial demand for approximately one third of the time during that period.

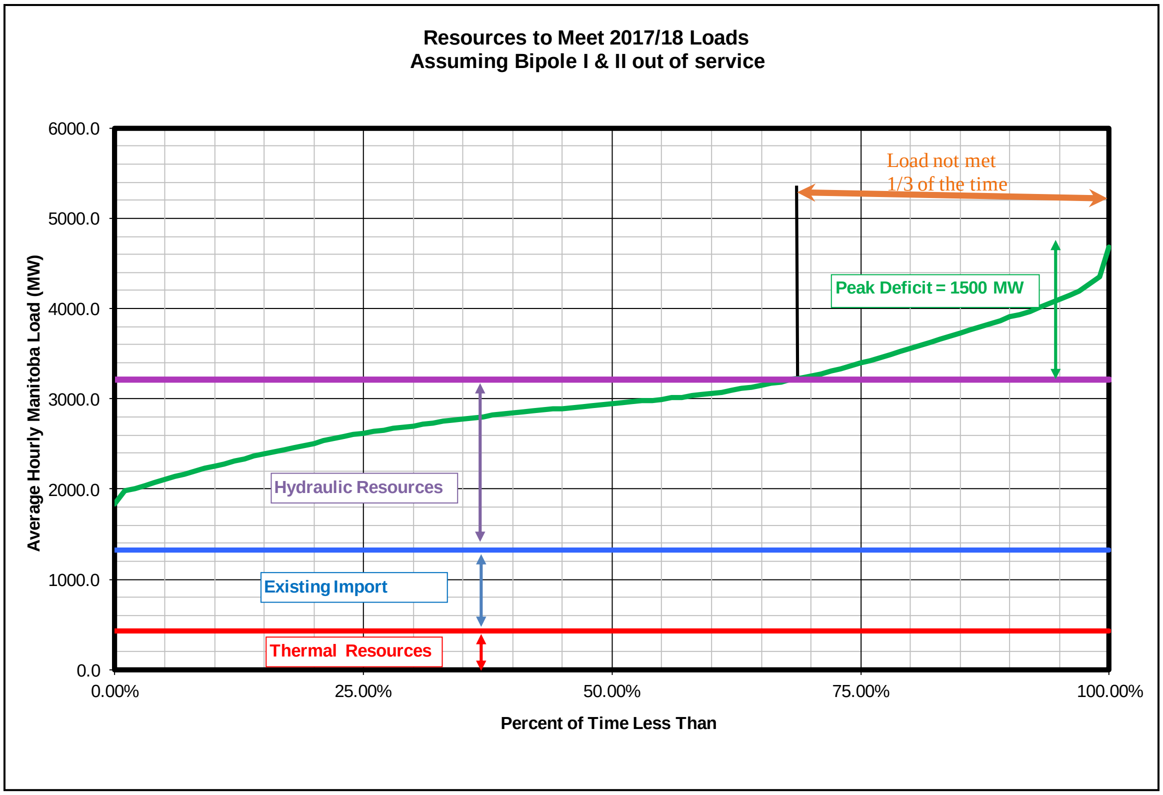

Figure 2.2-2: 2017/2018 Load Duration Curve for a Catastrophic Outage of HVdc

If an outage occurred in January 2017, be it at the Dorsey station or on the HVdc lines, as depicted on Figure 2.2-3, Manitoba Hydro would not be able to meet demand for 85% of the time during that month.

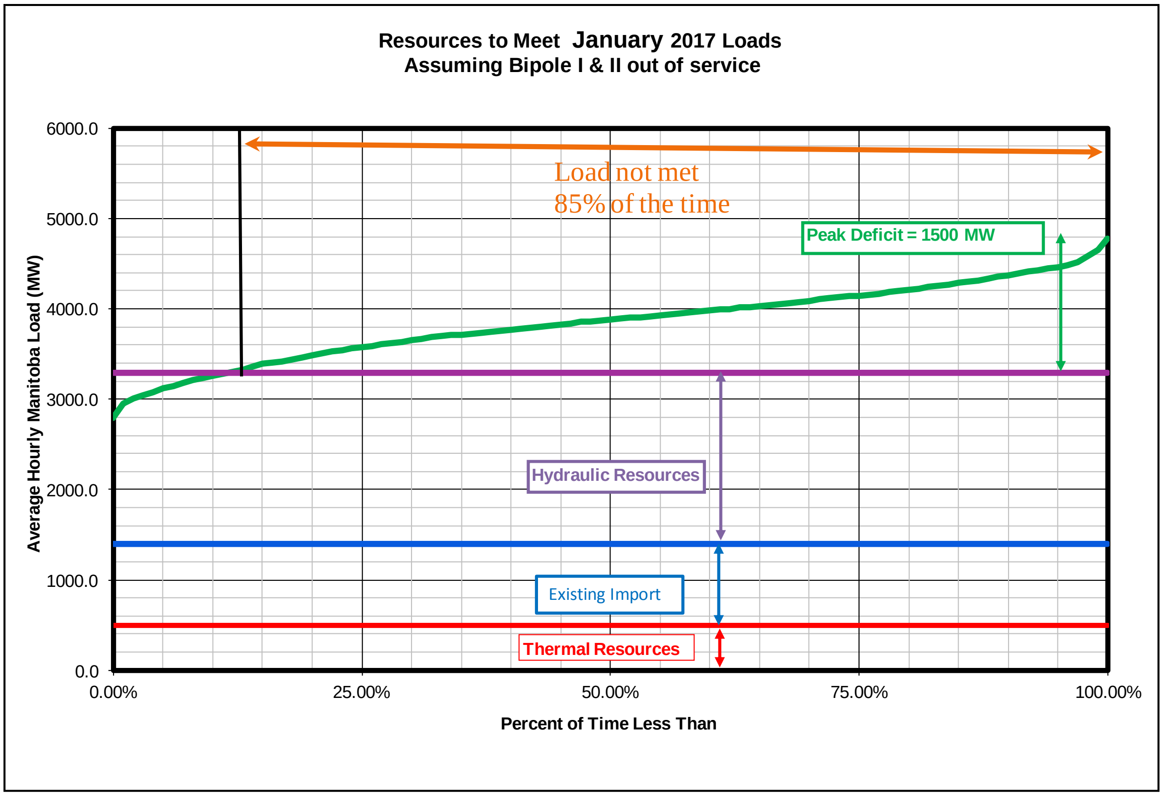

Figure 2.2-3: 2017 January Load Duration Curve for a Catastrophic Outage of HVdc

Given the significant consequences to Manitoba Hydro customers of an extended HVdc outage, the preferred reliability option should be able to minimize the unserved domestic load resulting from a catastrophic HVdc outage beyond the year it is put in service. A major factor considered in the selection of the 2000 MW Bipole III rating was the requirement to provide excess capacity beyond the 1500 MW deficit expected in 2017, the Bipole III in-service date, considering the extended time and outages required to add capacity in stages once the Bipole III is placed in service. A second important factor considered was compatibility with the existing system.

2.3 PROJECT ALTERNATIVES TO ADDRESS SYSTEM RELIABILITY

Alternatives to the project are the functionally different ways to meet the need for the Project and to achieve the Project's purpose. The following three alternative project options for enhancing the reliability of the Manitoba Hydro system were identified and evaluated:

1. The addition of 2000 MW of north-south HVdc transmission to continue to supply power from existing hydraulic generating sources in the north.
2. The addition of up to 2000 MW of gas turbines in southern Manitoba.
3. The addition of up to 1500 MW of new import tie lines to the United States (USA) to provide access to firm US generation, which is assumed to be comprised mainly of natural gas-fired generation, plus the addition of another 500 MW of natural gas-fired generation in southern Manitoba.

Other alternatives were considered to meet the Project's purpose, but were quickly ruled out as viable options. For example, some consideration was given to strengthening the existing HVdc transmission lines and converter stations to withstand higher stresses than those for which they were originally designed. While such work could lessen the vulnerability of the system, the probability of catastrophic outage associated with major events would still be too great to warrant strengthening as a solution on its own and, accordingly, it was not further evaluated. Staging of Bipole III was ruled out as being most costly due to the 1500 MW supply deficit and the minimal time between the initial stage and the completion stage.

2.3.1 Evaluation Criteria for Project Alternatives

Each of the three reliability improvement alternatives was planned and designed to meet the objective of continuing to serve Manitoba load in the event of an extended HVdc outage. The main criteria by which the project options were assessed are as follows:

1. *Project Cost* – The overall capital cost of each project alternative is a consideration for Manitoba Hydro in assessing project viability. Project cost was the main factor in the alternative evaluation.
2. *Implications to Manitoba Hydro during an extended catastrophic HVdc outage* – Given the potentially long repair times associated with potential catastrophic outages, each

project option was assessed having regard to the additional costs which would be incurred during such outages.

Implications to Manitoba Hydro during non-catastrophic outages and normal operation – The HVdc system currently has very little spare transmission capability (only about 300 MW). In the event of a more commonly occurring non-catastrophic HVdc outage such as a valve group or pole outage, this spare capacity is insufficient to transmit all available northern generation. Under this circumstance export curtailments or power imports may be necessary to meet load requirements. Accordingly, each reliability alternative has been evaluated for its ability to minimize additional costs and maximize value to Manitoba Hydro by providing coverage for planned/forced non-catastrophic HVdc outages.

Ability to facilitate future system expansion and enhance operational flexibility – Manitoba's growing domestic load will require future expansion of Manitoba Hydro's system generation capability. Over the last forty years, Manitoba Hydro has made huge investments in northern hydroelectric facilities and it is anticipated that future domestic load, as well as export requirements, will be met through additions to such infrastructure. Each of the three reliability options has also been assessed having regard to their ability to enhance operational flexibility as well as facilitate the choices available for future supply options.

Table 2.3-1 in Section 2.3.5 reviews the project alternatives relative to the project criteria. The discussion below reviews each project option studied and their respective evaluation.

2.3.2 Alternative 1 - Additional HVdc North-South Transmission

With respect to project cost, the construction of the proposed Bipole III is currently estimated at $3.28 billion in-service dollars. As noted in the previous section, the sizing of the Project is an important consideration. It has been sized for 2000 MW which will meet the projected reliability shortfall and enhance operational compatibility.

Long distance north-south transmission can be implemented using ac or dc transmission and the costs and operational attributes will vary according to the technology selected to carry out the project (see Section 2.4 below). Ultimately, the preferred means of HVdc overhead transmission is the most reliable, cost effective and technically viable option that also offers the greatest operational flexibility. The HVdc transmission line can be integrated into the Northern Collector System allowing operational flexibility of the three Bipole system. The addition of a third north-south HVdc line will increase efficiency of the north-south transmission system under normal operation, saving line losses of approximately 76 MW by splitting the generation from the Northern Collector System amongst three lines instead of two (Bipoles I and II).

Bipole III is the most attractive project alternative to protect the long-term supply of power, in that it continues to utilize existing northern hydraulic generation. The development of Bipole III also has the significant additional benefit of protecting Manitoba Hydro's options for future expansion of northern generating facilities both for domestic load and for export purposes, by adding additional transmission capacity into the system. While the primary driver of the project is system reliability, there is significant ancillary value to Manitoba Hydro in protecting and supporting the major investments it has made in northern generation facilities, as well as any future investments in northern hydroelectric resources. Moreover, failing to strengthen Manitoba Hydro's ability to transmit power from the north will reduce its attractiveness as a supply option to those export markets which Manitoba Hydro may in turn have to rely on for imports in an emergency situation.

2.3.3 Alternative 2 - Building Natural Gas-Fired Generation in Southern Manitoba

The second project alternative which has been assessed in the context of the potential load shortfall is the construction of approximately 1500 MW of natural gas-fired generation in southern Manitoba for 2017, and a further addition of 500 MW by the year 2025. The total cost of this gas turbine alternative has been estimated to be nearly $700 million (2010$) higher than that of the current estimate for the Bipole III Project on a present value basis.

The costs associated with this project alternative during any kind of outage would be significantly higher than the costs associated with transmission given that it would burn natural gas to generate power as opposed to utilizing northern hydraulic generation.

Gas capacity installed for system reliability would mostly be used for contingency situations; and accordingly, the capital investment will be used primarily as a "stand-by" source of power. The total project cost is comprised of the installation of gas turbines as well as the cost of ensuring a large firm gas supply on demand. The cost of the turbines themselves (2000 MW) is estimated to be $2.99 billion (2017$). Ensuring access to sudden and extensive demand for gas requires a firm gas supply for any given year throughout the 35-year planning horizon. An average cost of $181 million per year (in-service$) is required to secure a firm gas supply and consists primarily of a pipeline reservation fee with an additional cost for arrangements for the provision of fuel in the event that it is needed. It should be noted that the above cost of securing gas supply does not include the significant additional fuel costs that would be incurred when the gas turbines are operated during an outage.

In the event of a planned or unexpected outage, substantial operating, maintenance and fuel costs would be incurred for the natural gas-fired generation alternative. While idling in "stand-by" mode, gas turbines are required to run five percent of the time to ensure operational readiness. This in turn results in an additional annual fuel cost independent of turbine utilization.

During a catastrophic outage, the fuel, operating and maintenance costs associated with the supply of emergency power will be substantially higher for this option, and could be exacerbated by natural gas price volatility. There could also be delays associated with bringing the gas turbines from "stand-by" mode to full operational capacity. Use of non-renewable fossil fuels will increase the carbon foot print of this option in comparison to a transmission option linked to existing hydroelectric generation. In addition, this option would require the development of new transmission connections, with the possible exception of an installation near the Riel site, which would then require the construction of a gas pipeline to Riel.

Finally, this option significantly limits the potential for overall system development and enhancement given the lack of transmission connection to the major northern source of power from hydroelectric generating stations.

2.3.4 Alternative 3 - Importing Power

The third alternative involves the construction of a new high capacity transmission line between Winnipeg and Minneapolis, making it possible to import firm generation from a US supplier during an emergency. A 1500 MW interconnection of this nature is estimated to cost approximately $1.5 billion. In addition to this capital cost, this alternative requires firm power purchases in order to secure a reliable supply of import power, as well as 500 MW of natural gas-fired generation installed in Manitoba to meet growing load thereafter. A proxy for the cost of firm power purchases is the capital cost of adding 1500 MW of natural gas-fired generation in Manitoba, a standard proxy for new generation. Consequently, the total cost for the import alternative would consist of approximately $1.5 billion for building an interconnection and the capital cost of adding 2000 MW of natural gas-fired generation ($2.99 billion [in-service dollars]) plus operating costs. Accordingly, this option has the added cost of approximately $1.5 billion for building an interconnection but provides no additional benefits over the all-gas option.

The costs associated with this option during an outage will be similar or greater than the costs identified for the southern gas turbine alternative and would again expose Manitoba Hydro to natural gas price volatility.

A significant challenge associated with this project option is the need to engage US partners to construct the necessary generation and tie line facilities in the US. Building transmission outside of Manitoba and Canada is an unprecedented venture for Manitoba Hydro and would inherently have considerable risks involved. Given that Manitoba Hydro has been a supplier of significant amounts of firm clean energy to US customers for the past few decades, the concept of Manitoba Hydro requesting the US utilities to construct firm natural gas-fired generation for purchase by Manitoba Hydro would be a daunting request.

As with the gas supply option, this option significantly limits the potential for future opportunities for export sales as it does not enhance the transmission connection to the major northern source of hydroelectric power.

2.3.5 Recommended Alternative

The above discussion provides a description of the alternatives considered for improving Manitoba Hydro system reliability. Having regard to the criteria identified in Section 2.3.1, the Bipole III north-south transmission alternative is clearly the superior reliability solution at the least capital cost. In addition, it provides the greatest flexibility in operation and system expansion, with the least cost of emergency power during HVdc outages, catastrophic or otherwise. Furthermore, it is the only alternative that does not utilize energy generated from a non-renewable source and makes full utilization of the hydro-based generation system that Manitoba Hydro has developed over the past 50 years. The summary of the analysis of the three viable options having regard to the project criteria is set out below in.

Table 2.3-1: Evaluation Criteria for Project Alternatives

Objectives	Alternative 1 North-South dc Transmission	Alternative 2 Manitoba Natural Gas fired Generation	Alternative 3 Importing Power
Cost	Capital Cost (in-service dollars) $3.28 billion Fixed and variable annual cost $0.01 billion/yr	Capital cost amounts to $696 million more than Alternative 1 (Bipole III) on a present value basis Gas turbine installation cost $2.99 billion (in-service $) Fixed and variable annual cost $0.181 billion/year + variable costs	Capital Cost approximately $4.49 billion (in-service $) Annual costs subject to contract terms and variable costs
Savings/costs additional to the above	Reduction in transmission losses – approximately 26 M/year (2010$)	Annual cost of maintaining standby readiness	
Minimize unserved load during an extended HVdc outage	Meets reliability requirements until 2025. In the early years additional capacity available over the peak demand can reduce the import requirement costs	Meets reliability requirements until 2025 But heavily reliant on import from inception in 2017	Meets reliability requirements until 2025 Very high import dependency
Minimize costs to Manitoba Hydro during an extended HVdc outage	No additional costs	Significant fuel, operation and maintenance cost	Significant power purchase costs
Minimize costs to Manitoba Hydro during non-a catastrophic outage of HVdc	No additional costs	Fuel, operation and maintenance cost	Power purchase costs
Facilitate future system expansion and operational flexibility	Facilitates a reliability solution and an outlet for northern hydro development as soon as 2017	Provides only the reliability solution	Provides reliability solution and future potential for expansion of export access to US market

2.4 "ALTERNATIVE MEANS OF" CARRYING OUT THE PROJECT

Alternative means are the various technically and economically feasible ways the project can be implemented or carried out (CEAA 2007). Bipole III (overhead north-south dc transmission) was identified as the best alternative to meet the project need and purpose both economically and technically. A number of other means of carrying out the project were identified and evaluated. The alternative means identified included:

- ac versus dc transmission;
- Overhead lines versus underground option; and
- Overhead lines versus underwater option.

As discussed below, none of these alternative means were deemed to be viable options for this project. Alternative routes for the transmission line are reviewed in Chapter 7.

2.4.1 HVdc versus HVac Transmission

High voltage direct current (HVdc) transmission and high voltage alternating current (HVac) transmission are the two options for providing additional transmission capacity. The HVdc option requires a third transmission line from north to south that includes new converters at both ends. The HVac option would require new high voltage transformer stations and switchyards at both ends of the line and one or more stations at the intermediate points (voltage compensation) of the line for the transmission lengths in consideration.

The point to point distance from the Nelson River northern collector system to the load centers close to Winnipeg exceeds 800 km (Rudervall *et al* 2000; Seimens 2008; New England Power Service Company 1997).

The reason for development of HVdc systems was in part to deal with the excessive energy losses incurred over long distances when transmitting ac power. The use of dc transmission entails lower energy losses over distance but requires costly converter stations at each end of the system. Transmission losses on an HVdc transmission line are about 75% of the losses of an equivalent ac transmission line (New England Power Service Company 1997). Based on industry cost comparisons for HVdc and HVac transmission, HVdc transmission is most economical for distances exceeding on the average about 600 km (Rudervall *et al* 2000; Seimens 2008). Estimated loss savings with HVdc transmission can be more than 40 MW at full capacity utilization of the proposed transmission scheme.

A double circuit ac transmission on a single tower is considered to provide comparable capacity and availability to a bipolar HVdc transmission system. Due to their complexity, the capital costs for HVdc converter stations are higher than for high voltage ac substations. On the other hand, the transmission line costs are lower for HVdc transmission, given that only two sets of conductors are required as opposed to six for double circuit three phase ac transmission lines. Significantly smaller towers are required for HVdc versus ac. A 500 kV ac double circuit tower that provides adequate clearances and structural strength would be about 35% taller and much wider (Figure 2.4-1). One further major deterrent to using ac transmission is the need to connect the ac transmission line to the Northern Collector System. The greatest operational flexibility arises from a new transmission scheme that connects directly to this system, where power transfer between Bipoles I and II and the new scheme can be controlled without switching operations. This is easiest to achieve with HVdc due to its compatibility with Bipoles I and II.

In contrast, an ac line cannot readily be connected to the Northern Collector System without major and potentially very costly system changes. Since the existing north-south transmission is all HVdc, the Northern Collector System is isolated from (asynchronous to) the southern Manitoba interconnected ac system. This is unique to the Manitoba Hydro system and enables several special protection systems that enhance system stability, operability and export capability. A permanently connected ac line between the Northern Collector System and the south will disrupt this unique configuration. A north-south ac line permanently connected to the Northern Collector System will not be readily compatible with the existing system configuration without major reengineering of the existing protection and control schemes and the possible addition of new special protection systems (SPSs). An ac line left disconnected from the northern collector system will normally have the undesirable effect of delaying the process of power transfer to and from the ac transmission scheme, as it would involve switching generation onto the ac line and out of the northern collector system, and vice versa.

In essence, the analysis means that there are significant operating complexities and costly upgrades that would be required to make the ac transmission option viable. Even with such upgrades there will be switching delays in activating this transmission when required for system operations.

500kV 500kV Double Circuit

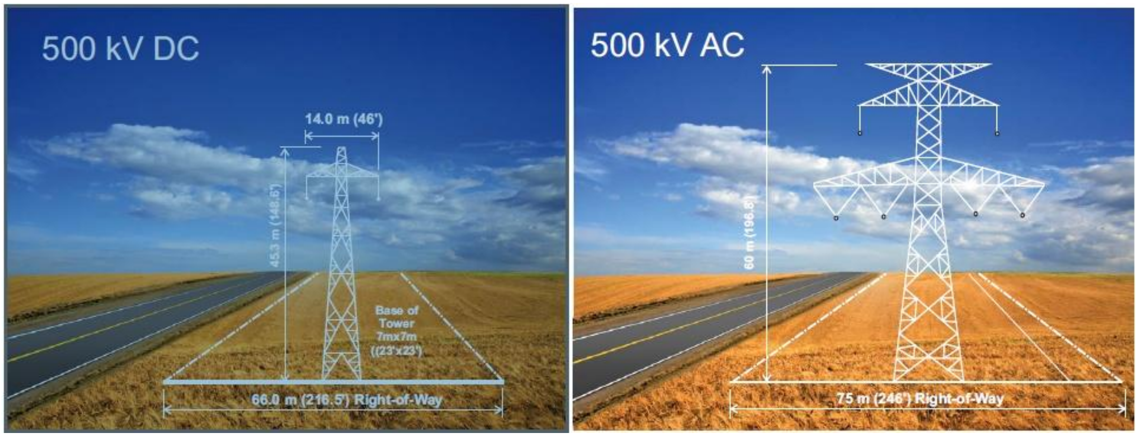

Figure 2.4-1: Typical Transmission Line Structures for 500kV 2000MW HVdc and AC Schemes

The double circuit ac line requires a significantly wider right-of-way (ROW), about 15% more than for HVdc as estimated by Manitoba Hydro. A 15% increase in ROW over a line length greater than 1300 km is significant, adding cost and requiring more land clearing (Table 2.4-1) to accommodate a 75 m wide ROW.

In summary, HVdc transmission is less expensive, less complex and provides the greatest operational flexibility with the existing Bipoles I and II. The ac transmission option is less desirable in the context of the reliability initiative; due to cost considerations and the additional complexity of operation it would impose on the Manitoba Hydro major transmission system as a whole.

2.4.2 Overhead Transmission Lines versus Underground or Submarine Cable Transmission

The point to point transmission distance from the northern collector system to the load centers close to Winnipeg exceeds 800 km. The actual transmission distance exceeds 1300 km for the west-side route that has been proposed. Overhead transmission is the most economical and technically mature technology for such long lengths of transmission. Underground ac cables require intermediate stations to control voltage along the line, which adds to the cost and operating complexity and reduces reliability. As a result, there is no bulk power transmission scheme in the world that uses underground ac cable technology for lines longer than 100 km in length.

Underground or underwater HVdc cables are rarely used where overhead transmission is technically viable. In fact, worldwide, there is no high power, long distance underground cable transmission; underwater dc cable transmission is used because it is the sole transmission choice for crossing large bodies of water and they are usually accessible to large ocean going cable laying ships. Underground or subsurface transmission at the 500 kV voltage level, even in favourable terrain conditions, is on average five to six times more costly than overhead transmission. Even if it were otherwise feasible, underground transmission requires a cleared right-of-way and does not eliminate concerns about the loss of vegetation and habitat, or about increased access (two of the principal concerns encountered with transmission lines in northern Manitoba) or disturbance to agricultural lands in southern Manitoba.

Underwater (submarine) cables laid in trenches in the lake bed of Lake Winnipeg have also recently been investigated conceptually as an alternative form of transmission for future transmission projects (Farlinger *et al* 2011).

A review panel consisting of multi disciplinary experts both within and external to Manitoba Hydro has investigated the potential use of the submarine or underground cables for long distance electricity transmission in Manitoba. The report was completed early this year and reviews the various potential routes, costs and performance issues associated with the application of these technologies to Manitoba (Farlinger *et al* 2011).

According to the above report, the current technology for cable transportation is limited to short cable lengths and therefore requires hundreds of splices (cable connections). It also identifies the life expectancy of underground and submarine cables as half of that of overhead lines. The failure rates are high (failure every 3 to 17 years). Repair times would be longer and costs would be higher considering the long winter months in Manitoba when Lake Winnipeg is ice covered. The report concludes that it is premature to consider submarine or underground cables as a means of delivering this project at this time.

2.4.3 Recommended Means

The above discussion provides a brief description of the alternative means considered for carrying out the preferred project of additional north-south transmission with overhead HVdc transmission being the recommended means. This option is by far the least cost alternative, is technically feasible, and provides excellent reliability. The comparison of the various north-south transmission options is set out below in Table 2.4-1.

Table 2.4-1: Comparison of North-South Transmission Options

	Overhead HVac	Overhead HVdc	Underground HVdc	Underwater Hvdc
Cost	Very high for the considered length of transmission	Least cost	5-6 times more than the HVdc	Highest
Feasibility	Feasible	Feasible	Feasible for short distances	Not currently feasible in Manitoba situation
Reliability	Generally technology offers excellent reliability However, for this application there is compromise due to operational complexities	Excellent reliability	Not as reliable due to frequent and long repair times, due to the many splices in U/G cables. Shorter life time than O/H lines Maintenance in winter months can be difficult	Not as reliable as even the U/G due to short cable pieces spliced together as demanded by the cable laying technology Maintenance in the winter months can be prohibitive

2.4.4 North-South Transmission Alternative Corridors

Once north-south HVdc overhead transmission was selected as the preferred means for addressing system reliability, several alternatives were considered in selecting a corridor to route the preferred transmission option. The geography of Manitoba essentially forms three corridors between northern and southern Manitoba: east of Lake Winnipeg, the Interlake Region, and west of Lakes Manitoba and Winnipegosis.

The eastern corridor had been under consideration early in the planning stages. However, a policy decision was made by the Provincial Government that the reliability project should not be routed within this corridor. A copy of the letter from the Minister responsible for Manitoba Hydro providing this policy direction to Manitoba Hydro is attached as Appendix 2A to this chapter.

The Interlake corridor is the location of the existing Bipoles I and II and is unacceptable as a location for Bipole III. In order to meet reliability criteria, physical separation from the existing major HVdc transmission facilities is required. Separation is the only effective way to reduce the risk of common outage of all three lines at the same time. Given the over concentration of transmission in the Interlake corridor, the third transmission line must be located within a corridor well separated from Bipoles I and II in order to obtain maximum reliability benefits (Teshmont 2006). As such a separation is not feasible within the Interlake corridor; this corridor was rejected for Bipole III routing.

As a consequence of the above analysis, the western corridor was selected for routing the Bipole III Project. Several studies have quantified the reduction in risk of common outage for the various routing options (Teshmont 2006). In general a significant improvement in reliability can be gained by the western routing option as compared to the Interlake corridor. Routing options within the western corridor are reviewed in Chapter 7.

2.5 SUMMARY OF RECOMMENDED PROJECT AND RATIONALE FOR SELECTION

The existing vulnerability of the Manitoba Hydro transmission system to extreme weather and other events which would result in an inability to serve a large portion of the Manitoba load over extended outage durations clearly justifies the need for the project. The over dependence on a single transmission right-of way in the Interlake or a single Dorsey converter station for transmitting about 70% of the hydroelectric generation in Manitoba to southern load centers has long been seen as unacceptable for reliably meeting the needs of Manitoba Hydro customers. Any extended loss of power of this magnitude, would have disastrous consequences for the Province of Manitoba and its residents.

- The recommended option to address the energy supply reliability of the Manitoba Hydro system is the 2000 MW Bipole III alternative. This is the most cost effective alternative that meets the entire supply shortfall in the event of an extended HVdc outage with minimal risk and the most effective operating flexibility. The Bipole III alternative is about $696 Million (2010 present value dollars) less costly than the natural gas-fired generation alternative.
- The 2000 MW Bipole III provides the required capacity to meet load in the event of an extended HVdc outage of Dorsey Station or the Interlake corridor. This option has minimal operating cost to Manitoba Hydro during such an outage, as it would continue to utilize the low cost northern hydraulic generation, as opposed to gas generation or imported power considered in the other alternatives (Manitoba Hydro 2011).
- Bipole III would also provide the much needed north-south spare transmission for normal day to day operation and provides significant savings in transmission losses. The estimated potential savings in losses are 76 MW at maximum generation

approximately amounting to 243 GWh/year, which can have a value of $26 million/year to Manitoba Hydro (Manitoba Hydro 2011).

- The availability of spare transmission also results in minimizing the cost of non-catastrophic outages of the HVdc system, by minimizing the curtailment of firm export power and/or the need for import to serve domestic load. The planned or forced non-catastrophic outages would result in significant additional operating costs for the gas or import alternatives (Manitoba Hydro 2011).
- Bipole III is the only alternative that facilitates reliable and economical system expansion for serving future load growth. Thus it has the most potential to meet reliability needs, as well as increases to domestic load and/or export requirements in future years with minimum cost. The gas or import options inhibit future participation in the export market which has historically enhanced Manitoba Hydro's ability to maintain low electricity rates.

2.6 CONCLUSION

A system reliability initiative, Bipole III is needed to provide a back-up transmission path, recognizing the existing vulnerability of Bipoles I and II, which share a common transmission line corridor and a single terminus at Dorsey Station. Based on both technical and economic feasibility, as well as environmental considerations, overhead high voltage direct current (HVdc) transmission is the best technology to provide the reliability and security of power for the province.

The process to select the route itself is described in greater detail in Chapter 7 of the EIS.

2.7 REFERENCES

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