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5 The Manitoba Hydro System, Interconnections and Export Markets

5.0 Chapter Overview

Chapter 5 – The Manitoba Hydro System, Interconnections and Export Markets begins with a more detailed overview of Manitoba Hydro's existing supply resources, building on the resource descriptions previously outlined in ***Chapter 4 – The Need for New Resources***. A description of the existing transmission system including interconnections is provided, including an explanation of the significant reliability and economic benefits of transmission interconnections. The unique properties of Manitoba Hydro's predominantly hydro system are also outlined, including the nature of typically having surplus energy available to sell into adjacent markets. The structure of interconnected markets is described, with particular emphasis on Manitoba Hydro's primary export market— Midcontinent Independent System Operator, Inc. (MISO). A high-level longer-term outlook of the MISO market is provided, describing some factors which are expected to put upward pressure on MISO capacity and energy market prices over the long-term.

5.1 Manitoba Hydro's Supply Resources

Manitoba Hydro's existing supply resources can be divided into four resource types: hydro-electric generation, thermal generation, wind generation and imports. Table 5.1 provides a summary of the available energy and capacity from existing system supply resources. Winter peak capacity is the maximum rate of power output, measured in megawatts (MW) that the generator can be relied upon to produce at the time Manitoba load is at its winter maximum. Energy produced is the expected energy generated measured in gigawatt hours (GWh; 1 GWh = 1,000 MWh = 1,000,000 kWh). Energy generated by the resources on Manitoba Hydro's system will depend on water conditions. Table 5.1 provides the energy produced for three flow conditions:

- dependable energy is that energy expected to be produced by each resource under the lowest water flow conditions on hydraulic record (e.g. severe drought) – also referred to as dependable generation
- average energy is the average of energy produced across the range of historic water flow conditions
- maximum energy is energy produced as a result of flood-like conditions across the system.

1 **Table 5.1** EXISTING SYSTEM RESOURCES [1]

Facility	Winter Peak Capacity (MW)	Energy Produced Under Flow Condition (GWh)		
		Dependable	Average	Maximum
Manitoba Hydro Operated Resources				
Pointe du Bois	64	320	550	582
Slave Falls	61	260	520	575
Seven Sisters	156	625	1,015	1,215
McArthur	57	230	390	470
Great Falls	127	545	915	1,010
Pine Falls	88	345	640	720
Grand Rapids	480	1,320	1,555	1,790
Jenpeg	135	695	925	1,150
Kelsey	285	1,760	2,180	2,120
Kettle	1,220	5,180	7,130	8,770
Long Spruce	1,007	4,240	6,080	7,665
Limestone	1,335	5,610	7,630	9,695
Laurie River (I&II)	10	40	60	80
Wuskwatim	200	1,250	1,520	1,650
AGC Reserve	-50			
Hydro Generation Total	**5,175**	**22,420**	**31,110**	**37,492**
Brandon Unit 5	105	811	125	125
Brandon Unit 6&7	280	2,354	23	23
Selkirk	132	953	18	18
Thermal Generation Total	**517**	**4,118**	**166**	**166**
Manitoba Hydro Operated Resources Total	**5,692**	**26,538**	**31,276**	**37,658**
Wind and Imports				
St. Leon Wind Energy		356	419	419
St. Joseph Wind Farm Inc.		421	495	495
Wind Generation Total		**777**	**914**	**914**
Contracted Imports Total	**550**	**2705**	**Varies**	**Minimal**
Market Purchases		**363**	**Varies**	**Minimal**
Purchased Resources Total	**550**	**3,845**	**914**	**914**
Total Existing Resource	**6,242**	**30,383**	**32,190**	**38,572**

[1] Note toTable 5.1
Dependable energy in the Manitoba Hydro Supply and Demand tables provided in Appendix 4.2 will be less than shown in Table 5.1 as the Suppy and Demand tables reflect water withdrawals over time.

5.1.1 Hydro Generation

Hydro-electric power is by far the most significant resource in the Manitoba Hydro generating system, providing almost 90% of the generating capacity that Manitoba Hydro owns and typically about 98% of electric energy. Generating stations (G.S.) located along the lower and upper Nelson River contributes approximately 75% of Manitoba Hydro's current hydro-electric capacity. Several major drainage basins, covering a large area of 1.4 million square kms, ultimately drain through the Nelson River.

Manitoba Hydro has 15 hydro generating stations on five river systems. Six of Manitoba Hydro's oldest hydro-generating stations—Pointe du Bois, Great Falls, Slave Falls, Seven Sisters, Pine Falls and McArthur—were built on the Winnipeg River between 1909 and 1955. The combined Winnipeg River generation capacity of 553 MW was sufficient to meet all of the electricity needs of southern Manitoba until the mid 1950's—by which time the Winnipeg River in Manitoba had been fully developed.

Initial hydro development in northern Manitoba was driven by mining projects. Laurie River I and II, totaling 10 MW, were developed in the 1950's by Sherritt Gordon Mines as an isolated system to serve a mining load at Lynn Lake. Manitoba Hydro took over the operation of the Laurie River G.S. in 1970, when the Town of Lynn Lake was interconnected to the Manitoba transmission system. The Kelsey G.S. was developed between 1960 and 1972 by Manitoba Hydro specifically for INCO's nickel mine in Thompson. Kelsey G.S. operated as an isolated system serving Thompson until it was connected to the southern Manitoba system in 1967.

The 480 MW Grand Rapids G.S. on the Saskatchewan River was developed between 1965 and 1969, completing the development of significant hydro resources in southern Manitoba. Decisions were made in the 1960's to pursue major hydro development on the lower Nelson River in northern Manitoba. On February 18, 1963, an agreement was completed between the Government of Canada and the Province of Manitoba for joint planning studies that led to the

development of Kettle G.S., Lake Winnipeg Regulation, Churchill River Diversion and the High Voltage Direct Current (HVDC) transmission system.

The 1,220 MW Kettle G.S. on the lower Nelson River was completed between 1970 and 1974. Kettle G.S. was followed by the 1,007 MW Long Spruce G.S. (complete 1977-79) and then the 1,335 MW Limestone G.S. (completed 1990-1992). Also completed in the 1970's were the Lake Winnipeg Regulation/Jenpeg G.S. (135 MW), and the Churchill River Diversion projects. The most recent hydro station is the 200 MW Wuskwatim G.S. on the Burntwood River, completed in 2012.

5.1.2 Thermal Generation

Manitoba Hydro has two thermal generating stations located in Brandon and Selkirk, Manitoba. The two-unit 132 MW Selkirk G.S. has natural gas boilers coupled with steam turbine-generators. Selkirk G.S. was completed in 1960 as a coal-fired station, and the boilers were converted to natural gas in 2002. The three-unit Brandon G.S. has one 105 MW coal-fired boiler coupled with a steam turbine generator completed in 1969, and two natural gas-fired combustion turbines, with a combined capacity of 280 MW, that were completed in 2002. Effective January 2010, *The Manitoba Climate Change and Emissions Reduction Act* restricted the operation of the Brandon coal unit to the support of emergency operations.

Thermal resources offer important support in Manitoba Hydro's system. Thermal resources can be used for capacity purposes to help meet peak loads during winter or when there are hydro-generation outages. In a drought, thermal resources would be expected to produce energy. Thermal resources can also be used as a source of supply during major transmission or other outages and for local area electrical requirements.

5.1.3 Wind Generation

Manitoba Hydro has purchased the entire output of the St. Leon and St. Joseph wind-generation farms in Manitoba—the combined maximum hourly generation capability of the two wind farms is 258 MW. Wind generation is an intermittent resource, in that hourly wind generation can only be relied upon when wind resources are available and are a function of the current wind speed, as opposed to hydro-electric generation which can be called upon immediately to meet current system generation requirements. Wind generation is assumed to have a zero winter peak capacity due to the intermittent nature of the resource and the fact that wind generators cannot operate reliably at temperatures below -30°C, the kind of temperatures which produce Manitoba peak winter load. Wind generation is not dependant on water flow conditions. Annual energy projections are estimated through statistical wind resource assessments and operating history. For planning purposes, 85% of the expected average annual energy from wind generation is assumed to be dependable energy.

5.1.4 Imports

Manitoba Hydro has four import contracts currently in effect as outlined in Table 5.2. The three Seasonal Diversity Agreements provide for the export of capacity for the six-month summer season (May 1-Oct 31) and for the import of capacity for the six-month winter season (Nov 1-April 30). The 500 MW Energy Services Agreement with Northern States Power provides firm import transmission, enabling Manitoba Hydro to make purchases from the MISO market. Imports of energy from a large power market such as MISO, whose resources are predominately thermal, pose very little delivery risk due to lack of energy supply, provided that the deliveries are scheduled on firm transmission service in a period which does not coincide with the peak load in the power market.

Table 5.2 CURRENT IMPORT CONTRACTS

Supplier	Contract Name	Capacity (MW)	Type	Term
Northern States Power	NSP 150 SD	150	Seasonal Diversity	May 1, 1995 to April 30, 2015
	NSP 200 SD	200	Seasonal Diversity	Nov 1, 1996 to April 30, 2015
	NSP 500 ESA	0	500 MW Energy Services Agreement	May 1, 2009 to April 30, 2019
Great River Energy	GRE 150 SD	150	Seasonal Diversity	May 1, 1995 to April 30, 2015

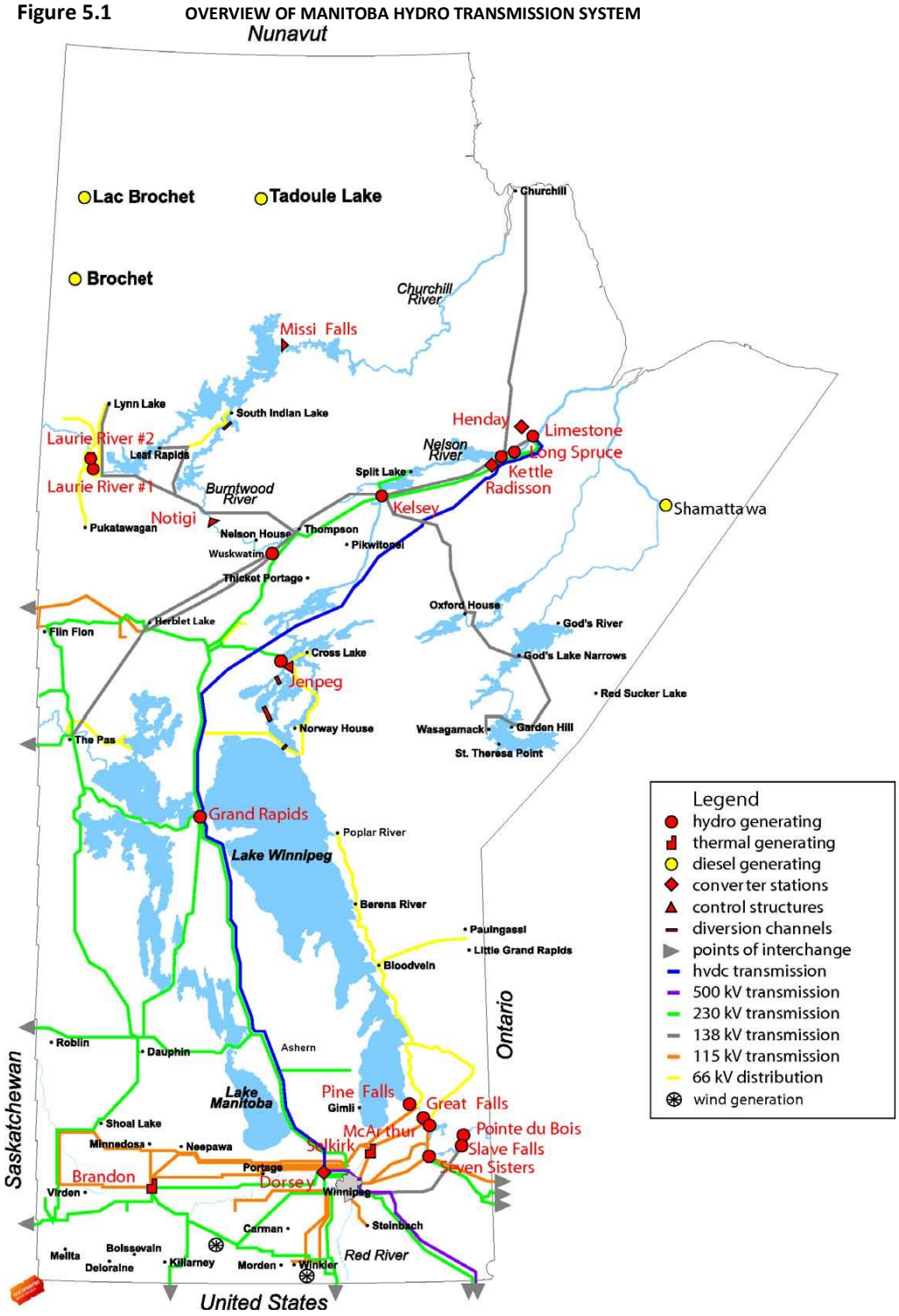
Note: Referenced to Manitoba Border

5.2 Manitoba Hydro's Transmission System and Interconnections

5.2.1 Transmission System Overview

Electricity is delivered from Manitoba Hydro's G.S. to Manitoba customers over a network of transmission lines as shown in Figure 5.1.

Figure 5.1 OVERVIEW OF MANITOBA HYDRO TRANSMISSION SYSTEM



The transmission system has two major components – the Alternating Current (AC) transmission system and the HVDC. The respective lengths of transmission lines connected to Manitoba Hydro's transmission network are summarized in Table 5.3.

Table 5.3 MANITOBA HYDRO SYSTEM- KM OF TRANSMISSION LINES

	Transmission Line Voltage				
	500kV	**230 kV**	**138 kV**	**115 kV**	**66-69 kV**
HVDC System	1,800 km				
AC System	200 km	5,000 km	1,400 km	2,900 km	7,200 km

As approximately 70% of the existing hydro-generation capacity in Manitoba is located on the lower Nelson River near Gillam, some 800 km north of the major population/load centre in Winnipeg, Manitoba Hydro's transmission system features a major north-south transmission element: the HVDC system. The existing HVDC system was designed to bring the combined output of the Kettle, Long Spruce and Limestone G.S. in the Gillam area south to the Dorsey Converter Station north-west of Winnipeg near Rosser, Manitoba.

The existing HVDC system consists of Bipole I and Bipole II and connects to the Northern Collector System. Bipole I consists of the northern Radisson AC-DC Converter Station, a 500 kV (kilovolt) DC (direct current) transmission line from Radisson to Dorsey, and a DC-AC converter station at Dorsey. Bipole I has a capacity rating of ± 463.5 kV and 1,854 MW. Similarly, Bipole II consists of the northern Henday AC-DC Converter Station, a 500 kV DC transmission line from Henday to Dorsey, and a DC-AC Converter Station at Dorsey. Bipole II has a capacity rating of ± 500 kV and 2,000 MW. The two HVDC transmission lines which connect the Radisson and Henday Converter Stations to Dorsey are 900 km in length and run on a single right of way. The construction of existing HVDC began in 1968 and the first phase of the system became operational in 1971 with the completion of Bipole I.

The Northern Collector System consists of a number of relatively short 138 and 230 kV AC transmission lines in the Gillam area which deliver power from the Kettle, Long Spruce and Limestone G.S. to the Radisson and Henday Converter Stations. The Northern Collector System is not connected to the AC transmission system and therefore operates in isolation (asynchronously). To provide operating flexibility for the management of transmission outages, it is possible to isolate two units (approximately 200 MW) at the Kettle G.S. from the HVDC system and instead direct their output on the AC transmission system.

The AC transmission system forms the bulk of the length of transmission lines in Manitoba. The system delivers power from Manitoba generating stations (other than Kettle, Long Spruce and Limestone, which are connected to the HVDC system), and power supplied from the HVDC system at the Dorsey Converter Station, to dozens of electrical stations around the province and to the export market. From these stations, the power is generally delivered to end-use customers through the distribution system; although there are a few large industrial customers who take delivery at high voltage directly from the transmission system.

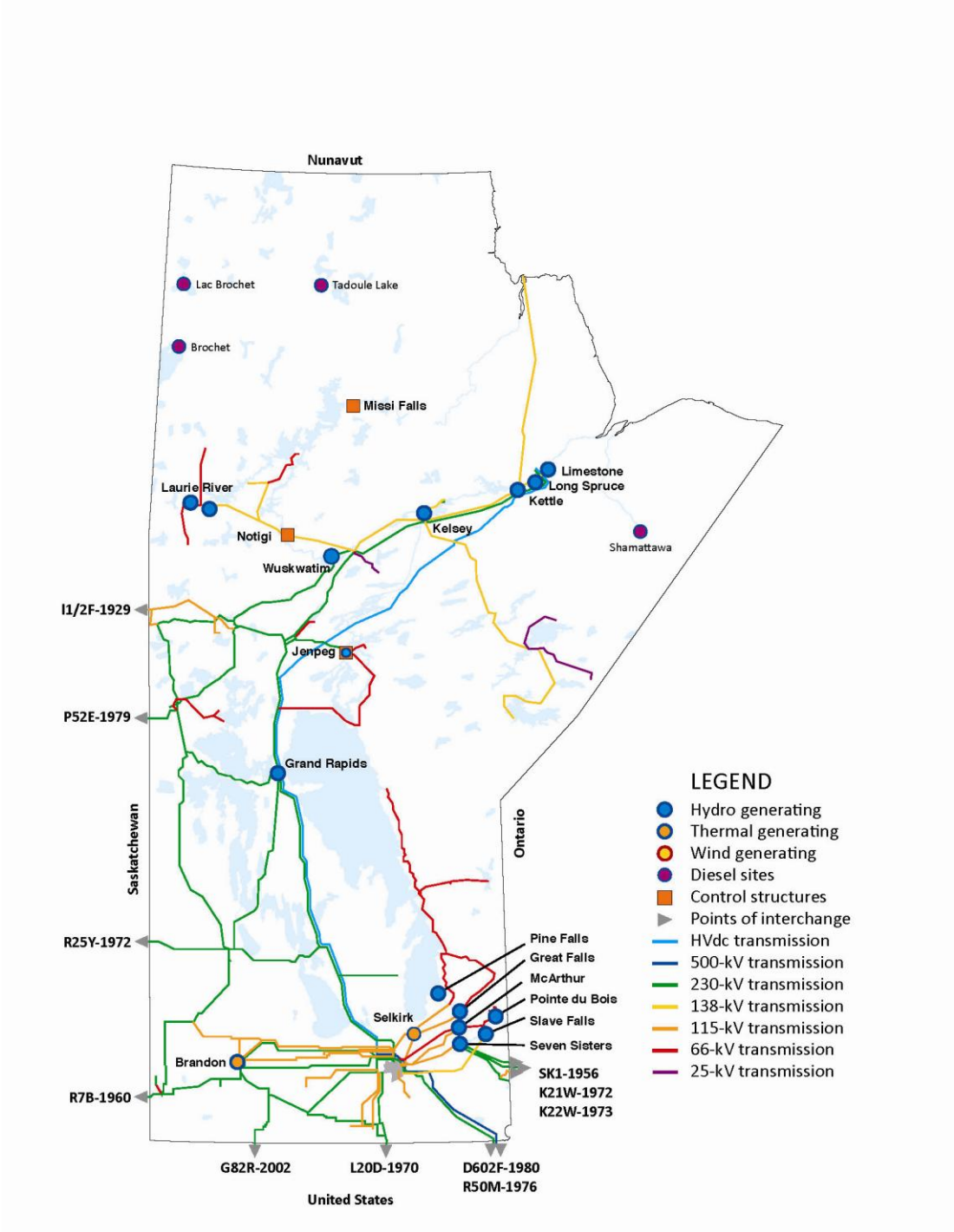
5.2.2 Manitoba Hydro's Transmission Interconnections Overview

Manitoba Hydro's transmission interconnections with adjacent provinces and states are a very important part of Manitoba Hydro's transmission system. This section describes how the transmission interconnections were developed and the significant reliability and economic benefits they provide to Manitoba. These benefits can be summarized as:

- improving reliability by enabling imports during drought conditions and under supply contingencies (e.g. temporary loss of supply due to equipment outages)
- increasing revenues by enabling the export of surplus hydro power and import of market energy at costs lower than the cost of thermal resources available within Manitoba.

Manitoba Hydro's existing transmission interconnections with Saskatchewan, Ontario and the U.S. are shown in Figure 5.2.

Figure 5.2 MANITOBA'S TRANSMISSION INTERCONNECTIONS



5.2.2.1 Transmission Interconnections with Saskatchewan

Manitoba Hydro currently has five cross-border interconnections with Saskatchewan. Circuits I1F and I2F were constructed around 1929 by a subsidiary of the Hudson Bay Mining and Smelting Company as an isolated system delivering power 96 kms from the Island Falls G.S. in Saskatchewan to a new mine located in Flin Flon, Manitoba. Circuit R7B was constructed in 1960 from the Brandon G.S. to Reston, Manitoba and then to the Boundary Dam G.S. in Saskatchewan to provide an alternative source of supply to the electrically remote Brandon area.

Circuit R25Y, routed between Dauphin/Roblin Manitoba and Yorkton, Saskatchewan was completed in 1972 and was driven in part by a 100 MW sale of surplus power from Kettle G.S. to Saskatchewan from 1972-3. Circuit P52E from The Pas, Manitoba to the E.B. Campbell G.S. in Saskatchewan was placed in service in 1979, improving the stability of the provincial power systems and also increasing the power exchange capability. Existing interconnections with Saskatchewan are summarized in Table 5.4.

Table 5.4 INTERCONNECTIONS WITH SASKATCHEWAN

Circuit Name	Voltage	Location	Year Completed
I1F/ I2F	115 kV	Island Falls, Saskatchewan to Flin Flon, Manitoba	1929
R7B	230 kV	Reston, Manitoba to Boundary Dam G.S., Saskatchewan	1960
R25Y	230 kV	Roblin, Manitoba to Yorkton, Saskatchewan	1972
P52E	230 kV	E.B. Campbell G.S. Saskatchewan to The Pas, Manitoba	1979

5.2.2.2 Transmission Interconnections with Ontario

Manitoba Hydro has three interconnections with Ontario. Circuit SK1 was constructed in 1956 from the Seven Sisters G.S. to Kenora, Ontario to facilitate sales to Ontario under the 1958 Lake St Joseph Agreement, and to provide a diversity of supply for Manitoba and the then-isolated northwestern Ontario power system. Circuits K21W and K22W were placed into service with Ontario in 1972 and 1973 to facilitate a firm power sale with Ontario for 50-200 MW in the 1972 to 1976 period using surplus power from Kettle G.S. The existing interconnections with Ontario are summarized in Table 5.5.

Table 5.5 INTERCONNECTIONS WITH ONTARIO

Circuit Name	Voltage	Location	Year Completed
SK1	115 kV	Seven Sisters, Manitoba to Kenora, Ontario	1956
K21W	230 kV	Whiteshell Station (Seven Sisters, Manitoba) to Kenora, Ontario	1972
K22W	230 kV	Whiteshell Station (Seven Sisters, Manitoba) to Kenora, Ontario	1973

5.2.2.3 Transmission Interconnections with the U.S.

In 1964, representatives of the Mid-Continent Area Power Planners (MAPP) commissioned a report to study immediate and long-range power requirements of the five study sponsors and to develop coordinated plans for new generation and associated transmission facilities with a particular emphasis on U.S.-Canada power interchange. The five utilities sponsoring the study were the Minnesota Power and Light Company, Minnkota Power Cooperative, Northern States Power Company, Otter Tail Power Company, and Manitoba Hydro. Key findings of the 1964 MAPP study were as follows:

> "For maximum economic benefits, the participating members must operate their individual systems as a single system for the purposes of pooling reserves, exchanging energy, and coordinating the installation of new generating facilities."
>
> "The cost of firm power supplied by Manitoba Hydro from their Nelson River development to the principal load centers of the Northern States Power Company in Minneapolis and to North Dakota in the Fargo area is less than firm power from any other source of generation. This reduction in the cost of energy amounting to about 10% is an economic benefit which may be shared by the participants."
>
> "The overall cost of energy from the Manitoba Development will be further reduced if maximum utilization is made of energy available from the use of unregulated water flow [e.g. opportunity hydro energy]."

The MAPP report and subsequent work led to the construction of Manitoba Hydro's first interconnection with the U.S.: the 230 kV Circuit L20D from Laverendrye near Winnipeg to Drayton and Grand Forks, North Dakota completed in July 1970. The U.S. interconnection was first used by Manitoba Hydro for import purposes during the winter of 1970/71, a time of tight supply just prior to the Kettle G.S. coming into service, 90 MW of capacity had been purchased from the three U.S. owners of the transmission line: Otter Tail Power, Northern States Power (NSP) and Minnkota Power. The export capability of this line was 375 MW.

The U.S. interconnection supplied interruptible ("opportunity") hydro power, providing U.S. utilities with a low-cost energy source and providing Manitoba Hydro with export revenue. Success helped drive construction of the second U.S. interconnection: a 230 kV circuit Ridgeway to Moranville (enroute to Duluth) owned in the U.S. by Minnesota Power and connecting

Ridgeway Station, located just east of Winnipeg, with Duluth, Minnesota. The line was approved in 1976, increasing the Manitoba-U.S. transfer capability by 250 MW.

As construction of the Kettle G.S. neared completion in 1974, construction began on the Long Spruce G.S. Manitoba Hydro was again expecting significant surplus energy once Long Spruce G.S. was completed in 1977-79. Two export sales agreements were signed with NSP in 1976: a 200 MW summer peaking capacity sale beginning in 1980, and 300 MW of Seasonal Diversity Sales also beginning in 1980. To facilitate these two sales, a third U.S. interconnection was constructed. The 860 km 500 kV circuit D602F between Dorsey Station and Forbes Station near Minneapolis went into service in 1980. While this line was justified primarily on the basis of the power sales, the line also provided an alternative source of supply to Manitoba in case of major outages on the HVDC network between the Nelson River and Winnipeg. The addition of this 500 kV line initially increased export transfer capability to 1,250 MW and ultimately increased transfer capability to the U.S. to 1,500 MW by 1985.

The addition of Limestone G.S. in 1990-92 and a 500 MW firm power sale agreement with NSP beginning in 1993 triggered a project to further improve the transfer capability to the U.S. The Manitoba-Minnesota Transmission Upgrade (MMTU) project added a number of electrical devices, including series capacitors, to the 500 kV line circuit, D602F; static var compensation at the Forbes station; and several other capacitor bank additions in Minnesota, increasing Manitoba Hydro's southern transfer capability by almost 30% to 1,900 MW.

The fourth interconnection with the U.S. was placed in service in 2002. The Glenboro, Manitoba to Rugby, North Dakota 230 kV circuit, G82R, was necessary to maintain import capability into Manitoba as required under the diversity sales agreements with NSP. The project increased long-term import capability to 700 MW, and increased the export capability to the U.S. interface system operating limit of 2,175 MW, which is still in effect. It should be noted that 225 MW of the system operating limit is utilized for delivery of operating reserves and transmission

reliability requirements and is not available for export purposes. The existing interconnections with the U.S. are summarized in Table 5.6.

Table 5.6 INTERCONNECTIONS TO THE U.S.

Circuit Name	Voltage	Location	Year Completed
L20D	230 kV	Letellier, Manitoba to Drayton / Grand Forks, North Dakota	1970
R50M	230 kV	Winnipeg, Manitoba to Duluth, Minnesota	1976
D602F	500 kV	Winnipeg, Manitoba to Minneapolis, Minnesota	1980
G82R	230 kV	Glenboro, Manitoba to Rugby, North Dakota	2002

5.2.2.4 Current Interconnection Transfer Capability

The current export and import transfer limits on Manitoba Hydro's interconnections during system-intact conditions are shown in Tables 5.7 and 5.8.

Table 5.7 EXPORT TRANSFER LIMITS

Interconnection	Firm Export Schedule Limit
U.S.	1,950 MW
Ontario	200 MW
Saskatchewan	150 MW

Table 5.8 IMPORT TRANSFER LIMITS

Interconnection	Firm Transfer Capability for the Planning Horizon
U.S.	700 MW
Ontario	0 MW
Saskatchewan	0 MW

The MW limits apply to both the on-peak and off-peak periods. Note that transmission transfer capability is affected by many factors and hence limit values can change. Transfer capabilities can change over the long-term as the transmission system evolves and in the short-term due to issues such as outages of individual lines. A portion of the maximum capability is reserved for transmission reliability purposes, which includes the delivery of operating reserves. Also of note is that the export limits are not additive: due to reliability considerations—and assuming supply were available—exports could not be simultaneously maximized in all three directions. The import capabilities from the interfaces *are* independent at the present time since no long-term import capability is available from Ontario or Saskatchewan. Import limits from Saskatchewan are dependent upon system conditions within Saskatchewan and vary on a month-by-month basis.

5.2.3 Reliability Benefits of Interconnections

Manitoba Hydro's interconnections provide significant reliability benefits in several ways:

- sharing of generation contingency reserves
- sharing of capacity resources due to load diversity
- importation of energy during drought conditions or extreme supply loss in Manitoba
- ability to supply cross-border load when this load is isolated from its system.

Sharing of Generation Contingency Reserves

A reality of power system operation is that individual generators or transmission components will have failures from time to time. To allow for such sudden generation or transmission outages, power system operators must have available spare generation that is ready to operate—units that are called operating or contingency reserves. If operated in isolation, each individual power system must carry sufficient contingency reserves to at least cover the largest single loss-of-supply event or contingency in their power system. For an interconnected power system, power system operators can pool their contingency reserves such that a single pool of contingency generators is available to cover loss-of-supply events over the entire

interconnected system—resulting in a significantly lower level of contingency reserves being carried overall and considerable cost savings. Manitoba Hydro currently has such a contingency-reserve sharing agreement with MISO, which requires Manitoba Hydro to supply 150 MW of contingency reserve, with 60 MW of that quantity spinning (or immediately available) and the other 90 MW available within 15 minutes. Firm transmission is reserved on the Manitoba to U.S. interconnection to supply these reserves.

Sharing of Capacity Resources due to Load Diversity

Loads in different power systems will tend to peak at slightly different times on a daily or seasonal basis. Daily diversity means that power demand peaks at different times of the day: peak times tend to vary slightly from system to system depending on factors as time zone, local economy, work hours, holidays, and local weather conditions. Seasonal diversity means that power demand peaks in different seasons: e.g., cold weather drives peak winter (heating) loads in the north, while hot weather drives peak summer (air conditioning) loads in the south. Such load diversities permit the sharing of capacity resources to meet overall peak system loads—and cost savings through the reduction in total resources needed to meet system demand.

Importation of Energy during Drought or Extreme Supply Loss

Manitoba Hydro's predominately hydro system is energy limited, and, therefore, can be short of water/energy in an extreme drought. Transmission interconnections provide an important source of supply during off-peak hours when there is ample excess capacity in the adjacent predominantly thermal system to provide off-peak energy to the hydro system. Such off-peak purchases allow water/energy to be conserved in Manitoba to meet peak loads. Imports may also be required for reliability purposes during major supply loss events such as the loss of the entire Interlake HVDC transmission corridor.

Ability to Supply Cross-Border Loads

Load that is located around the periphery of a power system may only have a single source of supply. If this load is located along a transmission interconnection, the load can then be supplied from the host power system, or in the event of a transmission outage, back-fed from the neighboring system. Such arrangements can reduce the overall level of transmission investment in both systems.

5.2.4 Economic Benefits of Interconnections

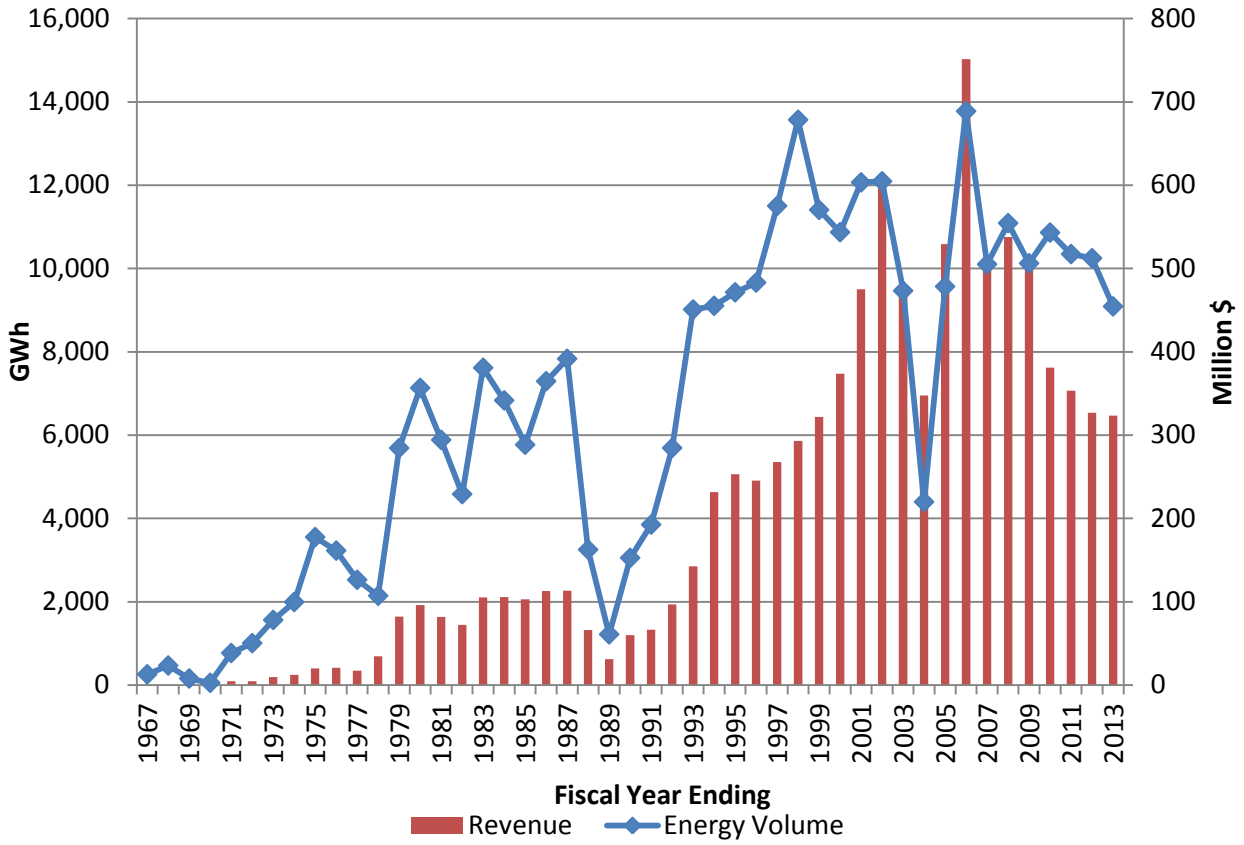
In addition to reliability and diversity, Manitoba Hydro's interconnections provide economic benefits as follows:

- exportation of surplus hydro power
- provision of a source of economic supply
- sale of ancillary services.

Exportation of Surplus Hydro Power

The most obvious benefit of interconnections to a predominately hydro system is that interconnections provide a means to export surplus hydro generation. In an isolated system with limited storage capability, such surplus energy cannot be utilized; instead, the water would be spilled and the value lost. In an interconnected system, surplus power can be exported at the value obtained by negotiated contract prices or at the current market value. A history of Manitoba Hydro's considerable export revenues, totaling over $9.5 billion over the last 35 years, is provided in Figure 5.3.

Figure 5.3 EXPORT SALES HISTORY



Source of Economic Supply

There are times during the peak winter demand period when it is economically beneficial to import lower-cost resources from outside of Manitoba rather than use Manitoba Hydro's own thermal resources. The fleet of wind, nuclear and thermal generation units outside of Manitoba is many times larger than that within Manitoba. Thus, for most hours there would be a more efficient and underutilized unit available to generate power than can be supplied from within Manitoba. Further, thermal units outside of Manitoba may already be operating at part load — resulting in lower startup costs and quicker availability.

As well, due to Manitoba Hydro's ability to store power by maintaining and increasing forebay levels at various generating stations, it is able to meet a portion of its off-peak domestic load

requirements by importing power—through interconnections with external markets—during those less expensive hours, with power returned to the external markets during the more profitable on-peak hours the next day. The ability of Manitoba Hydro's generation facilities to act as a storage battery is particularly significant in light of the substantial wind development occurring in MISO and across the U.S., and the fact that a significant proportion of energy generated by those wind resources occurs during off-peak hours when there is low demand in MISO and can be exported inexpensively to entities like Manitoba Hydro.

Sale of Ancillary Services

Manitoba Hydro has the capability to supply ancillary services into the MISO market. Ancillary services include spinning, supplemental and regulation-reserve services which are required by the system operator for the secure stable operation of the electrical system. Manitoba Hydro can offer up to 375 MW of ancillary services as an External Asynchronous Resource into the MISO market, supporting reliable market operations and providing another revenue stream as a result of the transmission interconnections.

5.2.5 Drivers of Development of Transmission Interconnections

As Manitoba Hydro's generation system has developed over the last 50 years to supply growing Manitoba load, Manitoba Hydro's transmission interconnections have similarly developed. Growth of the transmission interconnections has been carefully planned, and was anticipated even before construction started on the Kettle G.S. On February 18, 1963 an agreement was completed between the Government of Canada and the Province of Manitoba for joint-planning studies that led to the development of Kettle G.S. and the HVDC transmission system. The first paragraph of this landmark agreement states:

> "WHEREAS Manitoba has represented to Canada that the Nelson River has a power potential of the order of 4 million kilowatts of firm power, approximately 2 million kilowatts of which would be surplus to Manitoba's requirements for a

> considerable period and that, if any part of this potential is to be made available at economics rates in the near future, it must be developed for large markets outside of Manitoba to take advantage of economies of scale in which long distance transmission of electric energy would play a vital role."

Thus, over 50 years ago it was recognized that the economic development of large hydro resources in Manitoba required large markets outside of Manitoba in order to take advantage of the economies of scale. Transmission interconnections, it was understood, represent the means to achieve such economies of scale.

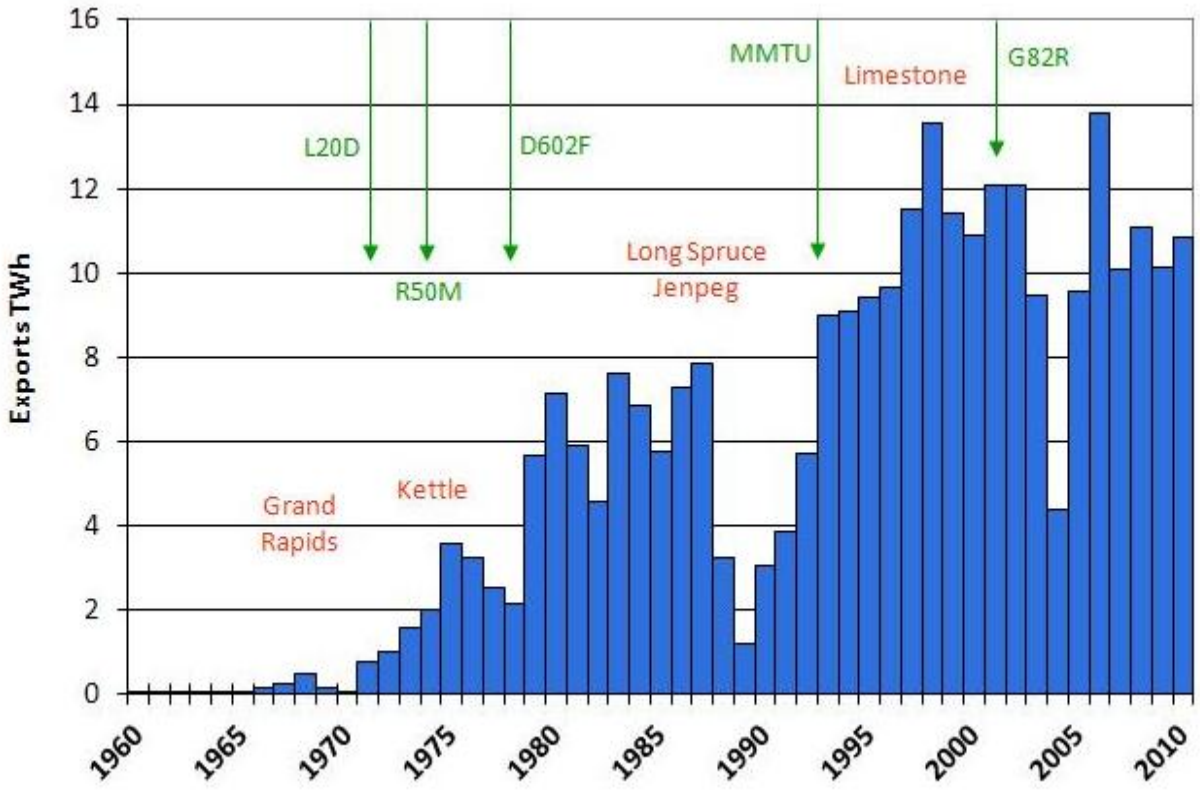
Since the joint-planning studies were undertaken in 1963, the Kettle, Long Spruce and Limestone G.S. were developed on the lower Nelson River along with directly related transmission interconnections. The relation between hydro development and transmission interconnection development is outlined in the Table 5.9:

Table 5.9 HYDRO AND TRANSMISSION INTERCONNECTION DEVELOPMENT

Major Hydro Station	Associated Transmission Development
Kettle G.S. – completed 1971-74	L20D, K21W, K22W, R25Y
Long Spruce G.S. – completed 1977-79	D602F, P52E
Limestone G.S. – completed 1990-92	MMTU Upgrade

The construction of these three major hydro stations and the associated transmission developments has led to parallel increases in export sales volume. A summary of the volume of energy exported over the past 50 years is shown in Figure 5.4.

Figure 5.4 HISTORY OF EXPORT SALES



5.2.6 Committed Major Transmission Development at Manitoba Hydro

Manitoba Hydro plans additions and enhancements to its transmission and sub-transmission systems to ensure that the systems will continue to operate reliably in the future as requirements change. Manitoba Hydro plans its transmission system to meet performance requirements set out in the North American Electric Reliability Corporation (NERC) Reliability Standards, Midwest Reliability Organization Standards, and Manitoba Hydro's own Transmission System Interconnection Requirements, which define standards for system adequacy, reliability, and security. The main drivers behind the need for new transmission facilities include the following: to improve safety, serve local load growth, maintain and improve reliability, provide transmission service, connect new generation, increase efficiency, and address aging infrastructure.

The ongoing transmission additions and enhancements help to ensure that the transmission system continues to meet Manitoba Hydro's mandate of serving the province with a reliable supply of electricity as well as meeting the performance requirements of Manitoba Hydro and its neighbouring utilities in Canada and the U.S.

Currently, Manitoba Hydro is developing the following two major projects for reliability purposes:

- Riel Station Reliability Project
- Bipole III Reliability Project.

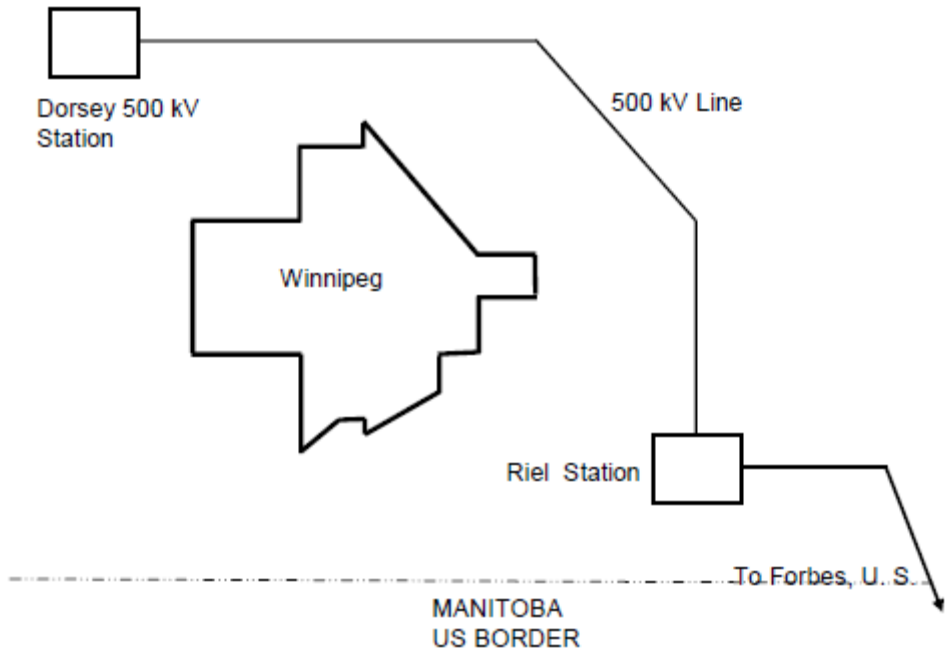
5.2.6.1 Riel Station Reliability Project

Maintaining a reliable supply of electricity under all conditions is a key tenet of Manitoba Hydro's planning and operational strategies. That includes ensuring that the utility has the ability to import power reliably during times of low water flows or during emergencies. The Riel Station Reliability Project will improve system reliability by adding an alternate terminal point for the existing 500 kV transmission line to the U.S., thereby preserving Manitoba Hydro's system import capability if there is a major outage at Dorsey.

The new Riel Station—as shown in Figure 5.5—will be located on the east Winnipeg periphery adjacent to major 230 kV and 500 kV transmission corridors. The location minimizes the need for new transmission corridors into and out of Riel and reduces the amount of new west-to-east transmission across Winnipeg by providing an alternate supply point to Dorsey, located on the northwest periphery of Winnipeg.

The project includes establishing the Riel Station site, installing 230 kV and 500 kV switch yards, installing a 230 kV to 500 kV transformer bank, sectionalizing the existing Dorsey- Forbes 500 kV AC MH-U.S. interconnection, and sectionalizing two existing 230 kV lines (Ridgeway-St. Vital lines R32V and R33V). The scheduled in-service date of the project is 2014.

Figure 5.5 CONCEPTUAL OVERVIEW OF RIEL STATION RELIABILITY PROJECT



5.2.6.2 Bipole III Reliability Project

Subject to environmental regulatory approval, Manitoba Hydro is also developing the Bipole III Transmission Project to enhance system reliability. The Bipole III Reliability Project will reduce the severity of the consequences of major HVDC system outages.

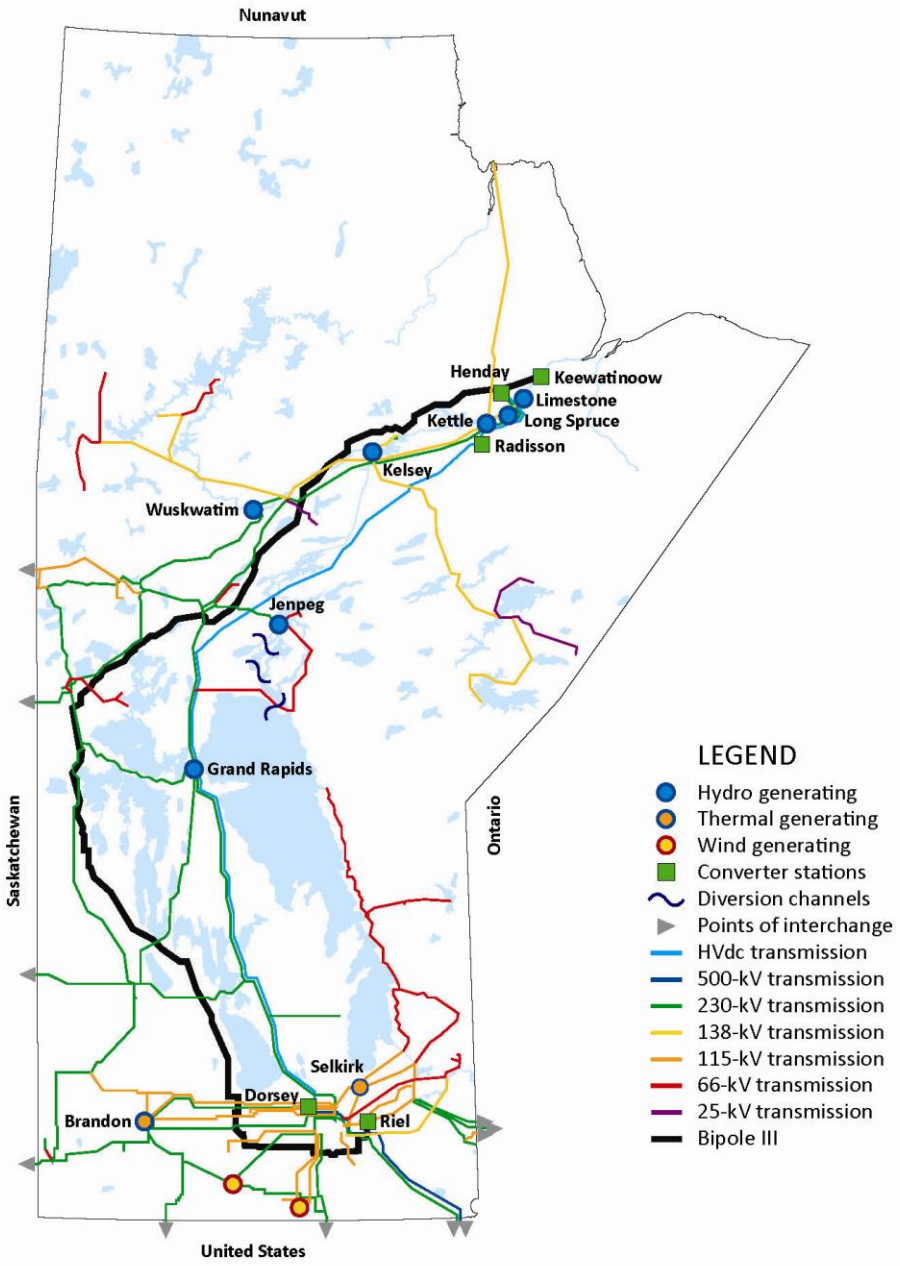
Approximately 70% of Manitoba's hydro-electric generating capacity is delivered to southern Manitoba via the Bipole I and Bipole II HVDC transmission lines. Bipoles I and II share the same transmission corridor through the Interlake region over much of their length from northern Manitoba to a common terminus at the Dorsey Converter Station. The existing transmission system is therefore vulnerable to the risk of catastrophic outages of either (or both) Bipoles I and II in the Interlake corridor and/or at Dorsey due to unpredictable events, particularly severe weather. This vulnerability, combined with the significant consequences of prolonged major

outages, caused Manitoba Hydro to pursue a major initiative to reduce dependence on the Dorsey Converter Station and the existing HVDC Interlake transmission corridor.

The conceptual schematic of Bipole III project is shown in Figure 5.6 below and includes:

- a new converter station, Keewatinoow, to be located near the site of the proposed future Conawapa G.S. on the Nelson River northwest of Gillam, Manitoba
- new 230 kV transmission lines connecting the Keewatinoow Converter Station to the northern AC collector system at the existing 230 kV switchyards at the Henday Converter Station and Long Spruce Switching Station
- modifications to the Henday Converter Station and the Long Spruce Switching Station to accommodate the new collector lines
- the development of a new +/-500 kV HVDC transmission line, 1,384 km in length and centered on a 66-meter-wide right-of-way, that will originate at the Keewatinoow Converter Station, follow a westerly route to southern Manitoba and terminate at a new converter station, Riel, immediately east of Winnipeg
- a new southern converter station at Riel Station.

Figure 5.6 CONCEPTUAL SCHEMATIC OF BIPOLE III PROJECT



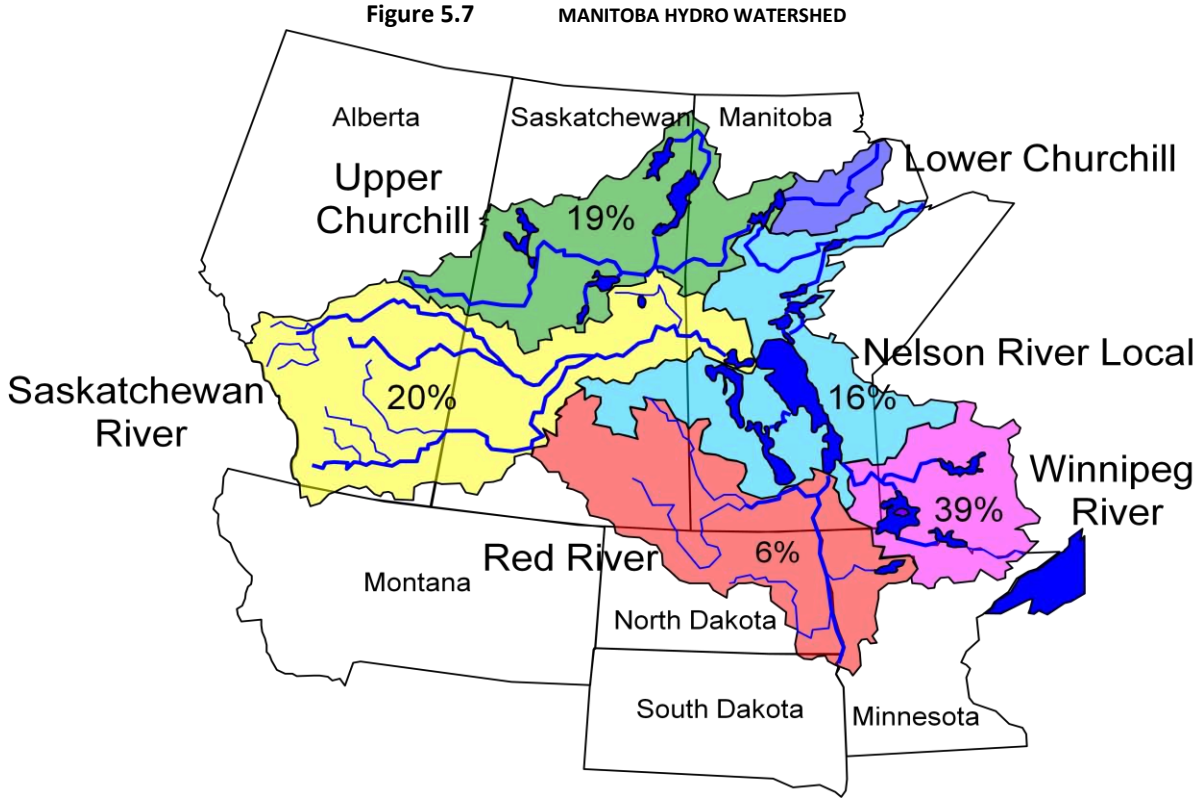
As a major reliability initiative, Bipole III is being developed with or without new hydro generation. However, Bipole III will also provide a transmission outlet for a large portion of power from the Keeyask and Conawapa G.S. should they be developed.

Upon receipt of the necessary *Environment Act* licence, construction is planned to commence in 2013 with a projected in-service date of October 2017.

5.3 Properties of Manitoba Hydro's Generating System

Manitoba Hydro's existing generation system is predominantly hydro-electric—with approximately 98% of the total electric energy supply from hydro resources in a typical year. The water supply for the Manitoba Hydro system is provided from a vast watershed. As shown in Figure 5.7, the watershed—with a footprint of 1,400,000 km^2—encompasses parts of four provinces and four states, stretching from the Rocky Mountains in Alberta to Lake Superior in Ontario and south into the U.S. reaching South Dakota. Drainage basins from five rivers are encompassed: the Saskatchewan, Upper Churchill, Nelson, Winnipeg and Red Rivers. Figure 5.7 illustrates the average contribution of energy from each of the major river systems to the total energy output from the system. Lake Winnipeg acts as Manitoba Hydro's main reservoir and provides seasonal storage of energy.

Figure 5.7 **MANITOBA HYDRO WATERSHED**



Manitoba Hydro's generation is greatly affected by variability in water supply. As an illustration of this variability, Figure 5.8 shows historic water supply as a percentage of long-term average for each year. It also demonstrates that there is over a 350% difference between the lowest and highest recorded water supply conditions on record.

Figure 5.8 HISTORICAL WATER SUPPLY VARIABILITY

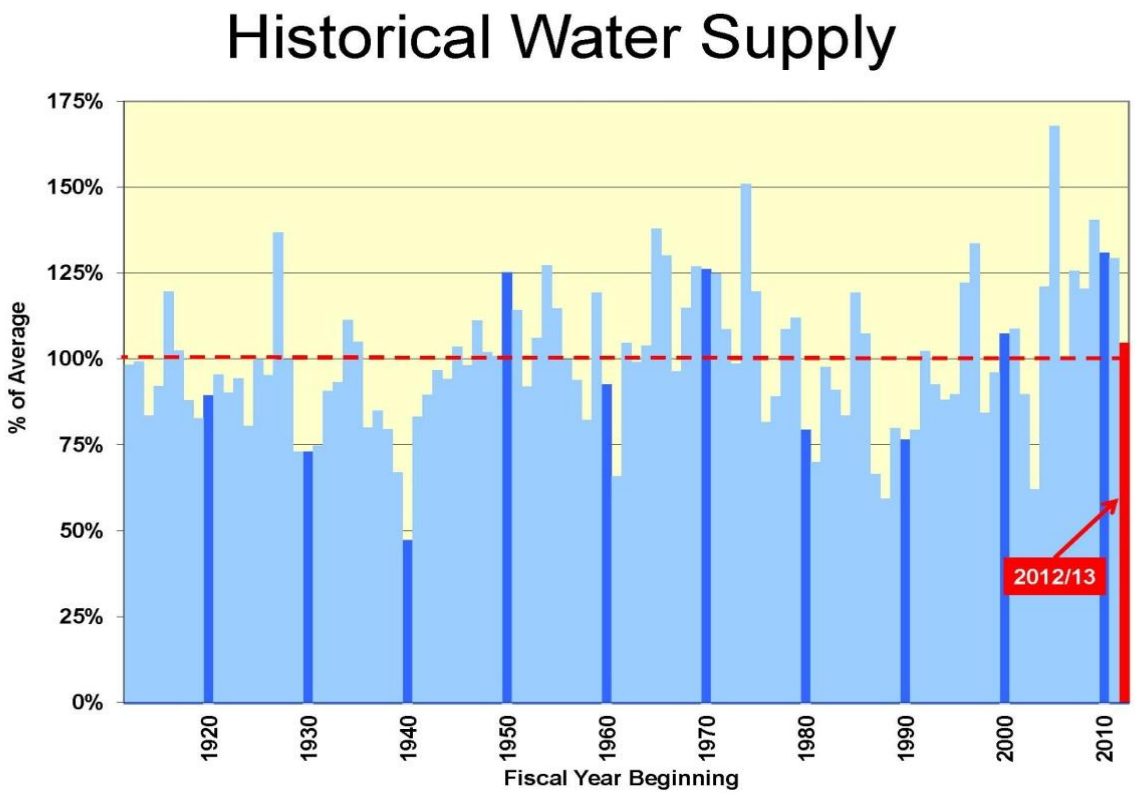


Table 5.10 below provides the variation in hydro-plant generation under a range of flow conditions. Based on the historic record and the current Manitoba Hydro system, hydro generation ranges from 22,420 GWh under dependable in-flow conditions, including available storage, to 37,492 GWh under high flow conditions.

Table 5.10 ENERGY PRODUCED UNDER FLOW CONDITION

Flow Condition	Energy (GWh)
Dependable	22,420
Average	31,110
Maximum	37,492

5.3.1 Surplus Energy by Design

Exports and transmission access to export markets have been and will continue to be critical for the effective and efficient operation of Manitoba Hydro's system and the development of Manitoba's hydropower resources.

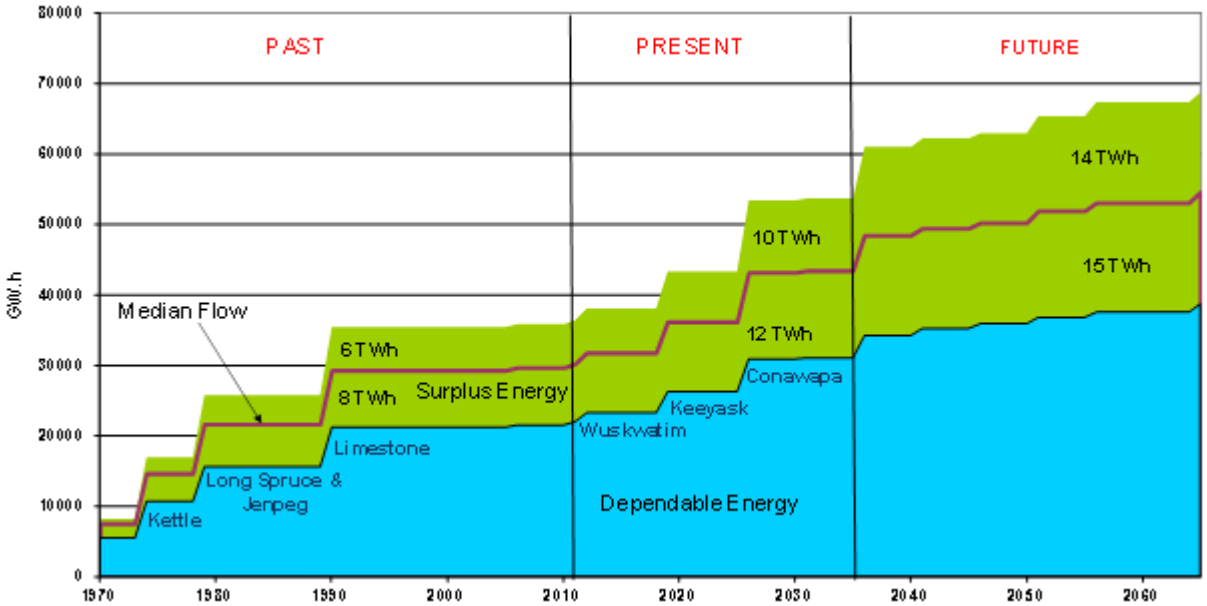
There are two aspects of hydro-electric development that result in surplus energy available for export. The first aspect is related to the variability of water flows described in the previous section. A predominately hydro system serving domestic load is designed to meet the energy requirements of that load under low-flow conditions (the critical-flow period), and is also designed with sufficient capacity to meet peak load requirements. By design, in all flow conditions other than the critical-flow period, there will be surplus water, i.e., other than that required for generation to serve the domestic load. In terms of capacity, each year there will be hydro-generation capacity surplus to domestic load requirements in all hours except for peak load conditions. Hence, in any year other than the critical-flow year, there will be water flows which are surplus to domestic requirements, and surplus generation capacity in most hours. These surplus flows could be spilled or—if the predominantly hydro system is interconnected to a neighbouring system—the water could be put through the system's unutilized generators and the surplus power sold on the export market.

The second aspect of hydro-electric development that results in surplus energy is the result of the large-scale increments of generation typical of hydro development. Potential hydro sites identified by Manitoba Hydro such as Conawapa and Keeyask are generally large and can satisfy many years of Manitoba load growth. The majority of the cost of developing a proposed hydro site is related to the substantial civil structures that are required. The actual generators, turbines and associated equipment are in the order of 25% of the total plant cost. Therefore, the practical decision is to develop the entire hydro-generating station to its maximum capability at the time of initial construction; and any surplus power beyond immediate needs can be made available to the export market. The large-scale increments of generation that

come with each new hydro project typically mean there are interim surpluses of both capacity and dependable energy above the amount required to meet Manitoba domestic load.

Therefore, as the system is expanded, the amount of both dependable and surplus energy is increased as illustrated in Figure 5.9.

Figure 5.9 RANGE OF SURPLUS ENERGY WHEN NEW HYDRO IS BUILT

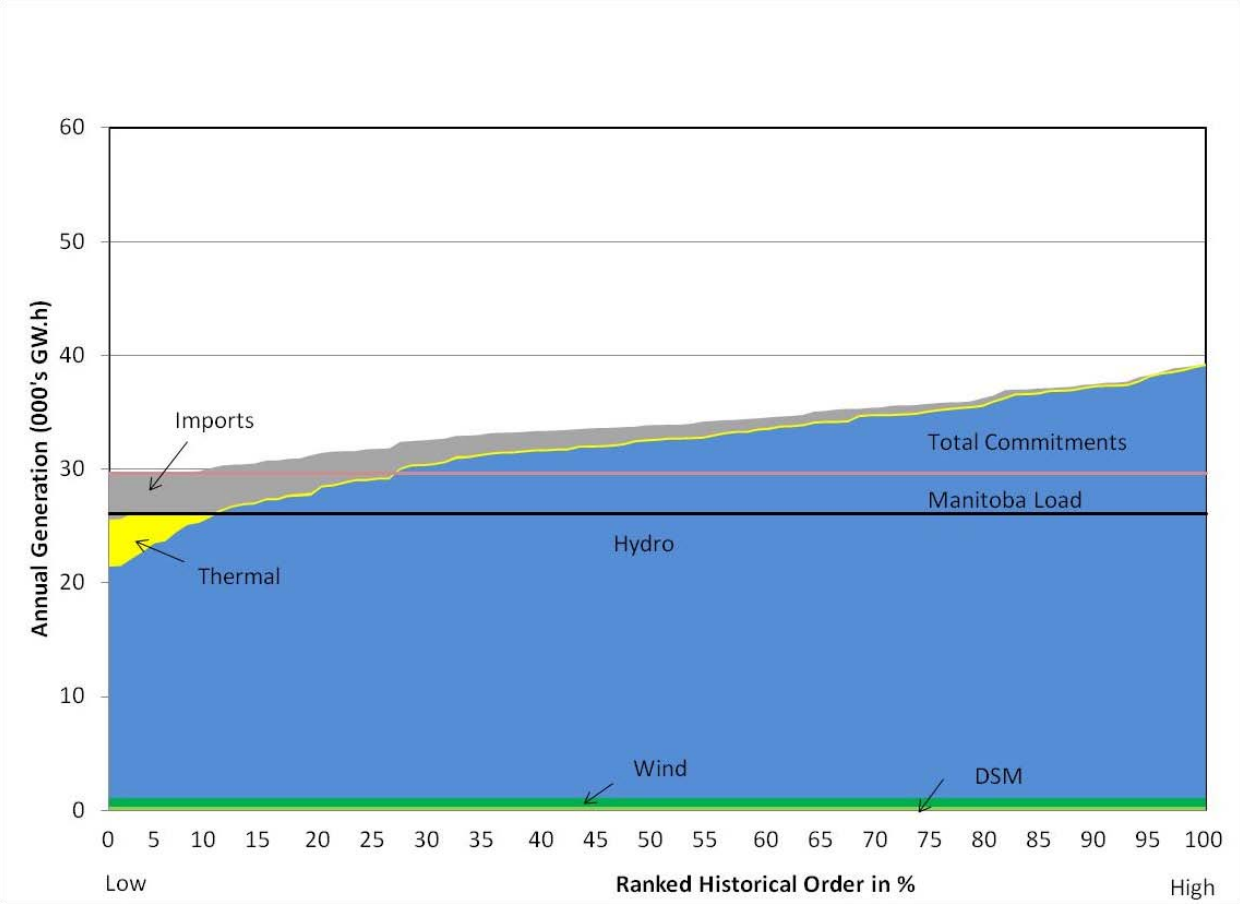


5.3.2 Resource Diversity

Due to variability in water supply, diversity in resource mix is essential to a predominantly hydro-electric generating system from both an economic and supply dependability perspective. Because the Manitoba Hydro system has strong interconnections to adjacent markets, there is access to ample sources of predominantly thermal-based supply to provide resource diversity as a supplement to thermal resources built in Manitoba. The specific quantity of imports that can be relied upon is specified in ***Appendix 4.1 Manitoba Hydro Generation Planning Criteria***. Manitoba Hydro has maintained a reasonable level of diversity in resource mix. For example, in 2014/15 under dependable flow conditions, Manitoba Hydro would be able to rely on thermal and import resources representing 25% of total supply.

Figure 5.10 illustrates the various resources that are able to meet Manitoba domestic load and firm export commitments across the historic range of water supply conditions. Noted on Figure 5.10 is the Manitoba domestic load for the year 2014/15 (black line) as well as total commitments including firm export commitments (red line). The range of historic water supply depicts the lowest-flow conditions (e.g., dependable conditions) as 0% and the highest-flow conditions as 100%. The mix of resources used to supply the 2014/15 total commitments range from the mix shown under dependable conditions to the mix shown under the highest-flow conditions. For example, under the lowest-water flow conditions on record (0%) Manitoba Hydro would rely on wind, hydro, thermal and imports to meet load requirements. As the capability of thermal plants is not affected by system water flow conditions, the thermal resources in Manitoba are most heavily utilized under dependable water flow conditions when hydro-electric energy supply is low. Under water flows below the tenth percentile, Manitoba Hydro can be expected to require the use of thermal or import energy to meet its Manitoba domestic load commitments. The reliance on thermal or import energy decreases at the time new hydro-generation is added and gradually increases over time thereafter; such an effect would occur under the Preferred Development Plan.

Figure 5.10 GENERATION SUPPLY SOURCES OVER A RANGE OF WATER CONDITIONS IN 2014/15



5.4 Interconnected Power Markets

5.4.1 Electricity Market Structure

The Canadian and U.S. power systems are operated as a collection of coordinated regional power systems. In many areas of the U.S. regional power system operators are also responsible for operating a state or regional power market. In Canada, two provinces—Ontario and Alberta—operate provincial power markets. Other Canadian provinces and U.S. states that do not have a regional power market generally provide open access to their transmission systems and engage in bilateral energy sales with counterparties in their region.

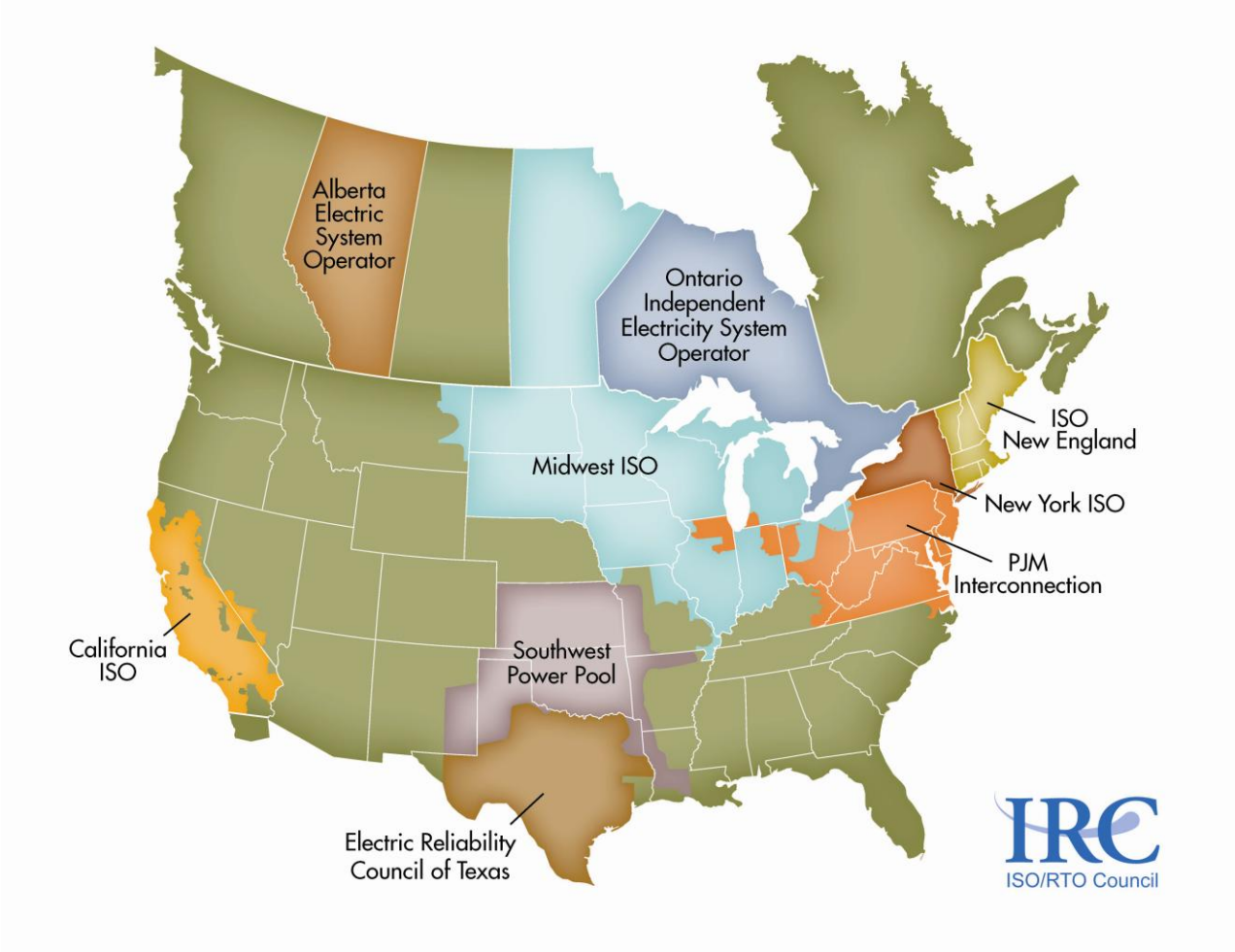
Most wholesale electricity markets in the U.S. operate under the regulatory requirements of the Federal Energy Regulatory Commission (FERC), a federal U.S. agency with jurisdiction over a number of energy matters including the transmission of electricity in interstate commerce and wholesale electricity rates. FERC must approve the electricity market rules for jurisdictional wholesale power markets. The U.S. federal Department of Energy (DOE) has jurisdiction over international electricity exports and the construction and operation of international transmission lines. Individual states have jurisdiction over determination of the need for new generation capacity and the siting of new power plants and transmission lines. In Canada, jurisdiction over intra-provincial electricity supply and regulation lies with the provinces. The jurisdiction of the National Energy Board (NEB) for electricity matters includes the construction and operation of international transmission lines, designated inter-provincial transmission lines and U.S. electricity export authorizations.

Regional power markets in the U.S. are operated by either a Regional Transmission Organization (RTO) or an Independent System Operator (ISO). These two structures perform similar reliability functions and must provide non-discriminatory access to the transmission network. RTOs generally have a broader multistate market region, while ISOs generally have a single state / provincial market region. Both RTOs and ISOs are FERC-approved entities and function as reliability coordinators, power grid operators and regional market administrators. An RTO has authority over a wider region and also acts as a market operator in wholesale power.

As shown in Figure 5.11, there are currently four RTOs and five ISOs in North America. The RTOs are PJM (Pennsylvania, New Jersey and Maryland), MISO, SPP (Southwest Power Pool) and ISO-NE (Independent System Operator New England). The five ISOs are CAISO (California Independent System Operator), NYISO (New York Independent System Operator), ERCOT (Electric Reliability Council of Texas), AESO (Alberta Electric System Operator), and the IESO (Ontario Independent System Operator). On Figure 5.11, areas not shown as being within an

RTO or ISO would have a central reliability coordinator and would utilize a bilateral market rather than a centrally operated power market.

Figure 5.11 NORTH AMERICAN MARKETS



Each market has its own unique characteristics, influenced by regional factors including available local energy sources, population density, regional geography and seasonal load patterns. The source of primary energy used to generate electricity varies widely from region to region, as outlined in Table 5.11.

Table 5.11 2011 SHARE OF ENERGY GENERATED BY FUEL TYPE FOR SELECTED ISOS

Fuel Type	NE-ISO	MISO	CAISO	PJM	NY-ISO	ONTARIO	U.S. (Total)
Coal	6%	75%	1%	47%	7%	3%	42%
Natural Gas/Oil	52%	5%	46%	15%	37%	15%	26%
Hydro	8%	1%	21%	2%	20%	22%	8%
Nuclear	28%	13%	18%	34%	31%	57%	19%
Solar	0%	0%	0%	0%	0%	0%	0%
Wind	1%	5%	4%	2%	2%	3%	3%
Geothermal	0%	0%	6%	0%	0%	0%	0%
Other	5%	0%	3%	1%	3%	1%	2%
Source	NE-ISO Market Data	MISO Market Assessment Reports	U.S. DOE EIA data for California	Cleantechnia	U.S. DOE EIA data for New York	Ontario IESO	U.S. DOE EIA data for U.S.

As indicated by Table 5.11, the MISO region is coal dominated, generating 75% of its electrical energy from coal in 2011 in comparison with 42% for the U.S. as a whole. Renewables (hydro, wind and solar) provided 11% of U.S. electricity overall in 2011. Thermal generation (coal, natural gas/ oil and nuclear) supplied 87% of the overall U.S. electricity in 2011. As discussed in ***Chapter 3 – Trends and Factors Influencing North American Electricity Supply***, the share of energy generated using coal in the U.S. is on the decline. Between 2001 and 2008, the annual share of coal-generated energy declined from 51% to 48%. Coal-fired generation last provided a 50% share in 2005 and is expected to be 40% in 2013 according to the U.S. DOE EIA.

5.4.2 Midwest Power Markets

Manitoba Hydro's largest transmission interconnection by far is to the south with the U.S. The U.S. interconnection has evolved to become substantially larger than either the Saskatchewan or Ontario interconnections for two reasons. First, the Minneapolis–Saint Paul metropolitan area, which has a population of over 3.3 million people (according to the 2010 U.S. census),

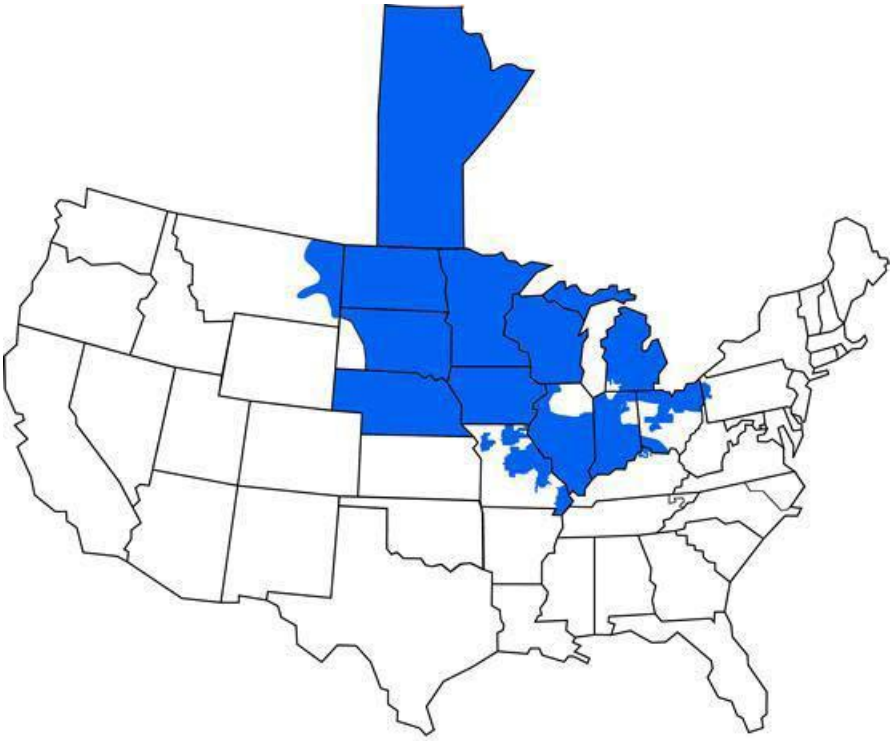
represents the closest population centre/electricity market to southern Manitoba that has a population larger than Winnipeg. Second, the state of Minnesota has few primary energy sources with which to generate electricity, having no oil, coal or natural gas according to the U.S. EIA. As a result, Minnesota is a significant net importer of electricity or the fuel to generate electricity, providing a good market for Manitoba Hydro's surplus power.

Manitoba Hydro's four U.S. transmission interconnections are generally owned in the U.S. by utilities who are members of MISO. As a result of the large U.S. interconnection and size of the Midwestern U.S. market, over 85% of Manitoba Hydro's exports have been sold into the MISO market in recent years. The relative importance of the MISO energy market to Manitoba Hydro is not expected to change quickly given the geographic proximity of Manitoba to the relatively large population/demand centers in Minnesota and Wisconsin.

5.4.2.1 MISO Organizational Overview

As of July 2012, MISO was the reliability coordinator for over 49,000 miles of transmission located in 11 states in the U.S. Midwest and the province of Manitoba (Figure 5.12). MISO was the first regional entity to be granted RTO status by FERC in 2001. In 2002, FERC accepted MISO's Open Access Transmission Tariff, allowing MISO to provide regional transmission services and requiring it to conduct transmission planning and expansion activities in the region. In 2005 MISO launched its wholesale energy market, one of the world's largest real-time energy markets, and began centrally dispatching generating units based on bids and offers cleared in the market. MISO began administration of its Ancillary Services Markets (ASM) in January, 2009—ancillary services include spinning, supplemental and regulation services required to secure stable operations of the electrical system. Transmission service, market and ASM rules are all contained under MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (TEMT).

Figure 5.12 MISO 2012 RELIABILITY COORDINATION AREA

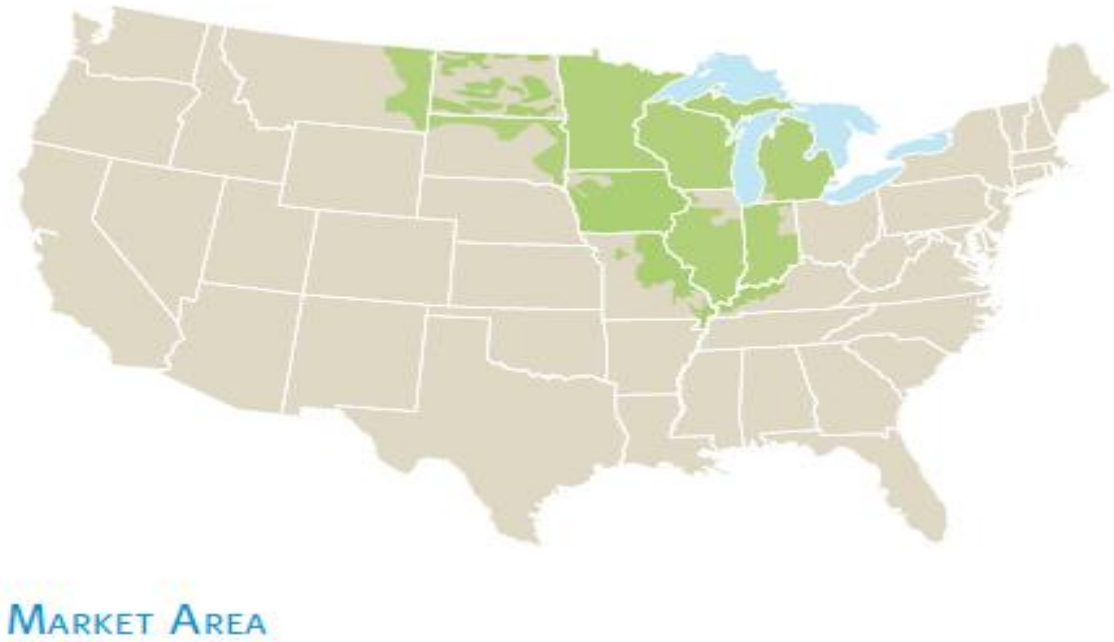


More information on the MISO market is contained in ***Appendix 5.1 – MISO Corporate Fact Sheet July 2012***. The data sheet does not reflect the pending MISO South (Entergy) integration, which will add 25,000 kms of transmission lines and 23,000 MW of generating capacity. Entergy is a large utility, to the south of the July 2012 MISO reliability coordination area, which is in the process of joining MISO. As the Entergy service territory is quite far from Minnesota and Wisconsin, Entergy integration is expected to have a minimal but positive impact on MISO and on Manitoba Hydro's market region.

5.4.2.2 MISO Market Overview

In addition to being a transmission system operator and reliability coordinator, MISO also operates power markets in that portion of its region known as the MISO market footprint, as shown in Figure 5.13.

Figure 5.13 MISO 2012 MARKET FOOTPRINT



The MISO market footprint is slightly smaller than the MISO reliability coordination area: some loads that are not under the jurisdiction of the U.S. FERC—such as Manitoba Hydro and U.S. power cooperatives—are part of the reliability coordination footprint but not the MISO market footprint. The MISO market footprint extends only to the Canada-U.S. border and Manitoba Hydro's sales and purchases with U.S. counterparties or with the MISO market occur at the international border.

MISO's July 2012 historic peak load for the market footprint was 98,576 MW; registered generation capacity in July 2012 was 131,581 MW. About 63,000 MW or 48% of the registered generation capacity is coal-fired generation. Manitoba Hydro's maximum potential supply into the MISO market is currently limited by the firm export schedule limit of 1,950 MW; therefore, based on the existing firm export schedule limit and current MISO market footprint, the Manitoba Hydro system would currently be able to supply up to 2% of the peak demand in MISO.

5.4.2.3 Manitoba Hydro's Relationship with MISO as a Coordinating Member

Manitoba Hydro's relationship with MISO is different than that of other U.S. utilities whose load and generation is located within the MISO market footprint. Manitoba Hydro's load is not served under the MISO TEMT, and Manitoba Hydro's generation is not directly dispatched based on instructions from MISO. Manitoba Hydro's governing legislation does not authorize the delegation of authority over its assets or operations to any third party except, in limited circumstances, subject to the approval of the Lieutenant-Governor in Council. Accordingly, Manitoba Hydro participates in the MISO market as a coordinating member via three agreements. The first two agreements, the Coordination Agreement and the Seams Operating Agreement, pertain to the coordination of transmission operations. The third agreement, the MISO Market Participation Agreement, binds Manitoba Hydro to the MISO market rules and a common agreement that all MISO market participants must sign.

Coordination Agreement

Under the Coordination Agreement, Manitoba Hydro and MISO coordinate on tariff administration services, transmission planning activities and contingency reserve sharing. In particular, Manitoba Hydro is responsible for serving its own load and MISO is responsible for certain tariff administration services, transmission settlements, administration of the contingency reserve sharing agreement and reliability coordination. The parties are jointly required to meet reliability standards established by NERC.

Seams Agreement

The Seams Agreement contains certain standard requirements including data sharing, close coordination of operations and congestion management procedures to be followed in cases where power flows on transmission lines result in congestion on the electrical grid.

Market Participation Agreement

The Market Participation Agreement provides that Manitoba Hydro shall take and pay for services in accordance with the TEMT and that MISO shall provide those services as requested.

5.4.2.4 MISO Market

At the consumer level, electricity appears to be a simple, convenient, homogeneous product; however, at the wholesale level, it is much more complex. This complexity is related to the inherent nature of electricity: it currently cannot be readily stored in large quantities and requires the continuous and instantaneous balancing of supply and demand. This balance requires a detailed understanding of many factors, including generator and transmission capability and availability, market rules, the impact of ambient conditions and time of year. ***Appendix 5.2 - MISO Market Products, Operation and Locational Marginal Pricing*** provides additional information on the MISO market.

There are three discrete categories of physical power products that are purchased and sold in the MISO market: energy, generation capacity and ancillary services. Specific market rules pertain to each product.

MISO operates two energy markets for energy and ancillary services, and facilitates a market for generation capacity in the footprint. The two MISO-operated energy and ancillary product markets are the Day-Ahead Energy and Ancillary Services Market (DA) and the Real-Time Energy and Ancillary Services (RT) Market. MISO facilitates the market for generation capacity—the MISO Resource Adequacy Construct—through its resource adequacy requirements for load, the tracking of bilateral capacity transactions, and through the MISO Planning Resource Auction for generation capacity.

MISO Market Pricing

To operate the power system and to determine energy prices, MISO utilizes a complex system called "security constrained economic dispatch" to determine which generators are required to operate and to calculate market prices each hour in the day-ahead and real-time energy markets. "Security constrained" means that MISO must observe system limits such as transmission-line capacities and ancillary service requirements when selecting which units to operate. MISO accepts offers to generate power from each generator available within the market footprint, and from adjacent external market participants including Manitoba Hydro. As of July 2012, there were roughly 6000 generators within the MISO market footprint eligible to offer power into MISO energy markets, with a total generation capacity of over 131,000 MW. MISO determines energy prices for each of thousands of locations on the power grid, a type of pricing is known as "locational marginal pricing" (LMP), explained in more detail in ***Appendix 5.2 - MISO Market Products, Operation and Locational Marginal Pricing.***

The LMP at each location includes a system-wide energy price component, a line-loss component, and a congestion component, in which transmission lines play a key role. When there is insufficient transmission to deliver all of the lowest-cost power to the load, the transmission line is said to be congested. The market operator will then dispatch an alternate and more expensive generator located where it will not cause transmission lines to overload. The costs of re-dispatching higher-cost generation to address transmission congestion will cause the LMP to be higher at those re-dispatched locations. The divergence in prices across a market region directly reflect the cost of congestion (e.g. the incremental cost of the higher-priced generator that has to be dispatched due to the line limitation) as well as physical energy losses on the transmission line between the two pricing nodes.

MISO has a comprehensive framework in place to annually assess potential regional transmission upgrades through the MISO Transmission Expansion Planning (MTEP) process. The primary goal of the MTEP process is to develop a comprehensive plan that meets the reliability, policy and economic needs of the region, making the benefits of an economically efficient

energy market available to all MISO stakeholders. Projects that show they will cost-effectively reduce local congestion and thereby improve market efficiency are identified and their costs are allocated across all regional stakeholders. A centralized approach to transmission planning helps ensure that cost-effective measures to reduce congestion costs are pursued, mitigating the risk of structural, significant and prolonged price divergences emerging within a region.

MISO Market Marginal Generation

In an energy market, generation resources are offered into the market based on the units' variable operation cost. For any given time period, these offers are then stacked based on price and the last, or most expensive, unit that is cleared or needed to meet load is called the marginal unit. All dispatched units receive the market clearing price.

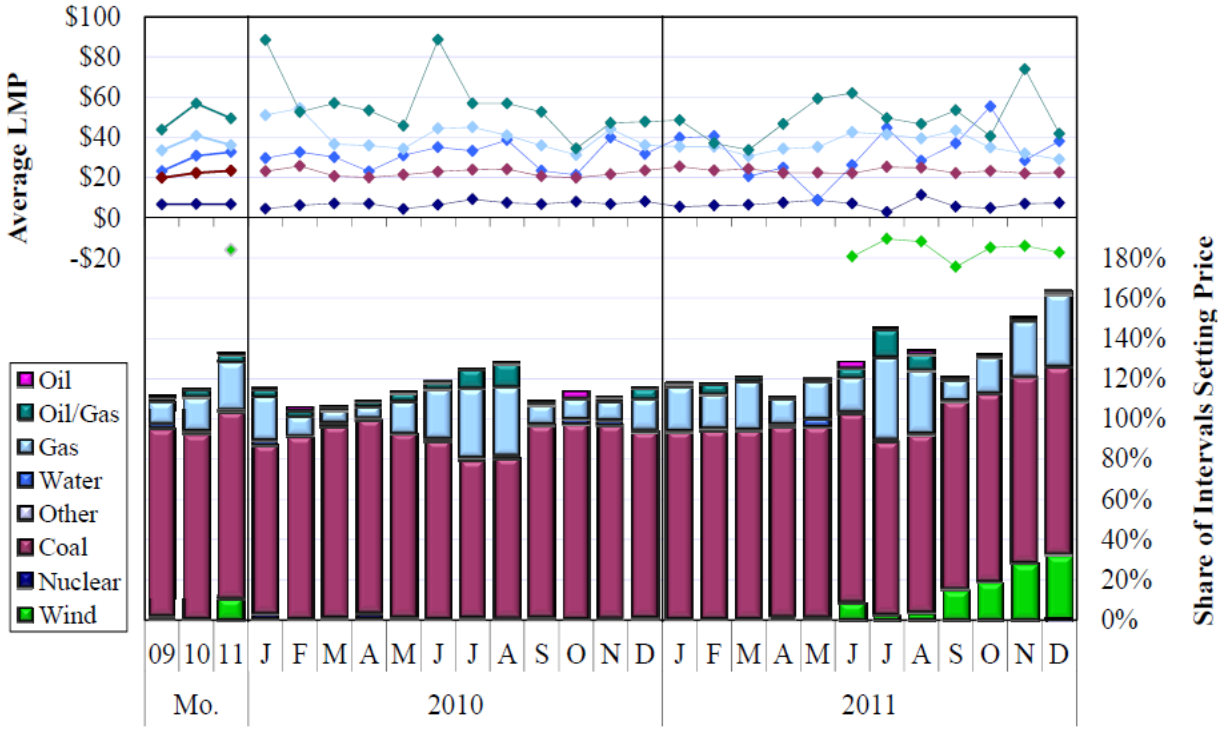
The largest component in a generator's variable cost is fuel prices; therefore fuel costs have a direct and notable effect on marginal prices. Because renewable resources (biomass excepted) have no fuel costs their variable costs are very low. For this reason, renewable resources are at the bottom of this dispatch "stack", with fossil fuels being ordered above (i.e. dispatched after) renewables. In a region such as MISO where fossil fuels dominate installed capacity (the top 80% of the generation "stack"), it can be expected that fossil fuels would almost always be setting the marginal clearing price.

MISO publishes limited high-level aggregated data regarding marginal generation by fuel type that can provide indicative data to understand what is occurring in MISO. In interpreting the data, one must be aware that more than one type of unit can be the marginal or pricing setting unit at any one time. Coal can frequently be the marginal fuel for a large portion of the market footprint, but due to localized transmission limitations (congestion), natural gas or even wind can be the marginal fuel for a portion of the market—creating two or more marginal generators at one time. MISO has recently created the Dispatchable Intermittent Resource (DIR) category

for wind resources, which allows them to be partially dispatched (e.g. decrease in output only) and thereby participate in setting locational prices.

Table 5.12 from the MISO Independent Market Monitor's 2011 State of the Market report provides recent complete historical data regarding the percentage of total hours each of the various fuels are setting prices in MISO.

Table 5.12 MISO – HOURS VARIOUS FUELS ARE PRICE SETTING



The following are selected observations provided by the Independent Market Monitor on the above results:

- coal-fired resources set the energy price in 93% of (hourly) intervals, including virtually all of the off-peak intervals. Frequently congestion causes both natural gas and coal to be on the margin in the same interval in different areas
- the correlation between natural gas and energy prices is not stronger because natural gas-fired resources only set prices in 23% of the intervals; although, these periods tend to be the highest load intervals.

At first glance, wind appears to have a significant and growing role in setting marginal prices. However, as noted previously, this is a result of having multiple price setting generators at one time and the wind generators setting the price only in small transmission-constrained areas of the power grid.

Taking into account the limitations of the available data, the following conclusions can be made regarding marginal generation in MISO:

- due to the dominance of low cost coal resources in MISO, coal is on the margin many hours of the year
- natural gas does play an important role, primarily during peak load hours
- looking out into the future, lower natural gas prices, the development of more natural gas capacity and impending coal retirements would all have the effect of placing natural gas on the margin increasingly over time.

MISO Resource and Emission Displacement

Manitoba Hydro's exports and imports have implications on the dispatch of resources in the MISO region. Generally, every additional MWh offered by Manitoba Hydro will result in the displacement of a MWh of some type of fossil-fuel generation. Based on MISO Independent Market Monitor's 2011 annual report, coal was on the margin 93% of all hours in the year. Natural gas was the only other significant marginal fuel, on the margin 23% of the time. As previously noted, due to transmission constraints it is possible for more than one fuel to be on the margin in any particular hour.

Coal generation typically emits on the order of 0.9 to 1.1 tonne of CO_2/MWh, while natural gas can range from about 0.3 to 0.8 tonnes of CO_2/MWh depending on the technology and its efficiency. Manitoba Hydro currently assumes that its exports displace (and its imports result in) 0.75 tonnes of CO_2/MWh. This reflects a marginal generation mix of various fossil-fuels and technologies.

Given that the marginal generation remains primarily coal (at an emission rate of about 1 tonne of CO_2/MWh), the 0.75 tonnes of CO_2/MWh factor used by Manitoba Hydro is considered conservative with respect to estimating the emissions displaced by exports. However, the 0.75 emission factor may underestimate the emissions associated with imports. While Manitoba Hydro does not forecast the annual marginal export displacements, it expects that as coal units retire and more natural gas generation is built, the marginal emission factor should decrease over time.

5.4.2.5 Long-Term Resource-Planning Decisions vs. Energy Market Prices

Two time horizons are employed for energy resource decisions – the current or operating horizon, and the long-term planning horizon. As indicated in Table 5.13, in the operating horizon, capital costs are considered sunk costs and are not considered when generators prepare their power market supply offers. Hence, when DA and RT prices are determined they are driven by the variable operating cost of the thermal generators – and there is no certainty of recovery of capital costs. This issue has lead to the formation of generation capacity markets to provide an additional source of revenue by which generators can recover their capital or fixed costs. In the MISO market, the full recovery of the costs of generation capacity are not included within the energy market price, and are typically recovered from end-use customers via other rate-base mechanisms in addition to MISO energy market charges. On the planning horizon, beyond at least two years from the current operating horizon, future capital costs are relevant as they have not yet been incurred.

Table 5.13 DECISION HORIZON COMPARISON

Operating Horizon	Long Term Planning Horizon
Very short-term	Beyond two years or more
Operation of plant will be determined by current system requirements	Expected capacity factor of plant is considered: • Low capacity-factor requirements: often a gas peaker (SCGT) with high operating but low capital costs is selected. • High capacity-factor requirements: now CCCTs considered (moderate capital and operating costs); previously base load coal plant (before CO_2 consideration);
Capacity (also called fixed or capital) costs are sunk and are not considered. Embedded capital costs not in energy price and recovered via other rate-base mechanisms	Capacity costs are not yet incurred and are considered along with variable production costs
Thermal generators offer into market at variable cost of production. Decision is whether operation is required to meet load or not	Decision is what type of plant to build to meet projected future operating requirements

On the long-term planning horizon, capital or capacity costs have not yet been incurred or committed so they cannot be considered a sunk cost. A customer considering the long-term purchase of new supply from Manitoba Hydro as an alternative to a thermal resource will consider both the variable operating costs (the energy market price), and the capital costs (the value of capacity) of the thermal resource. Hence, Manitoba Hydro is able to price its long-term sales of capacity and dependable energy to include both energy revenue based on future expectations of energy prices, and additional capacity revenue based on the annual fixed costs of the alternative thermal resource.

5.4.3 Canadian Export Markets

5.4.3.1 Ontario Market

IESO commenced operations in 2002 and is responsible for the safety and reliability of the transmission grid as well as the operation of the wholesale electricity market in Ontario. Manitoba Hydro has been an active participant in the IESO since its inception, and has transacted with the former Ontario Hydro as far back as 1956. The IESO operates a real-time market for energy and operating reserves, which is similar in design to the MISO real-time market, although it uses uniform prices across the province of Ontario rather than locational marginal prices. Ontario does not have a day-ahead market or a capacity market, although, since 2005 the Ontario Power Authority (OPA) has acted as a central purchaser of generation capacity under long-term contracts to meet Ontario's needs.

The Ontario energy market is approximately one-quarter the size of the MISO market. The OPA notes that the Ontario energy demand has been declining since 2005 and is not expected to grow until at least 2020[2]. The annual Ontario peak demand peaked at 26,000 MW in 2005 and has since declined to 24,000 MW. Similarly, annual Ontario energy consumption peaked at 155,000 GWh/year in 2005 and has since declined to 145,000 GWh. Declines in the Ontario load have been primarily driven by weaker economic conditions and higher electricity prices[3].

When the IESO commenced market operations in 2002, the electricity supply situation in Ontario was so tight that the market operator had to issue public appeals for load reductions on hot summer days. In 2005, the Ontario government formed the OPA to prepare an integrated system plan for conservation, generation and transmission, and to procure new supply, transmission and DSM either by competition or by contract.

[2] Forecast of Ontario Electricity Demand- Status and outlook of Ontario demand & next steps, Ontario Power Authority, January 2013.
[3] Ontario Electricity Demand- 2012 Annual Long-Term Outlook, Ontario Power Authority, Summer 2012.

Since 2005, OPA, acting under specific government supply-mix directives, has contracted for 5,100 MW of natural gas-fired generation and 2,900 MW of non-hydro renewable generation (primarily wind power), brought 2,000 MW of existing nuclear power plants back into service, and closed 4,300 MW of coal generation.[4]

By November 2014, the total wind and solar generation connected both to the transmission and distribution networks in Ontario is expected to exceed 6,800 MW and provide 14,900 GWh of annual energy[5]. Generation reserve margins in Ontario are currently in excess of 30%, much higher than required for system reliability. By 2008, Ontario had become a significant net exporter of electricity. However, government-mandated coal closures in Ontario and a return to slow load growth has meant that Ontario's production capability is expected to exceed demand in 2020.

Manitoba Hydro currently has an effective export capability into Ontario of 200 MW. There are two major barriers to a major long-term Manitoba Hydro power sale to Ontario: distance and Ontario government policy. The Ontario interconnection is with Northwestern Ontario (that portion of Ontario west of Wawa, Ontario), a large, sparsely populated area with a proportionally small peak load of 750 MW.

Northwestern Ontario itself is interconnected to southern Ontario through two 230 kV transmission lines (the East-West Tie) with a transfer capability of about 325 MW and running north of Lake Superior from Thunder Bay to Wawa, Ontario. There is already ample generation and a relatively small load within Northwestern Ontario and the Ontario interconnection/east-west tie-lines are insufficient for a major new sale into southern Ontario.

[4] Outlook for Electricity Demand and Supply in Ontario, Ontario Power Authority, November 6, 2012.
[5] 18-Month Outlook Update From June 2013 to November 2014, Ontario IESO.

Therefore, a major power sale to Ontario would require a major new transmission line from Manitoba to southern Ontario terminating near Toronto. The length of such a new transmission line to southern Ontario would be about three times the distance to Minneapolis, adding to the complexity of building transmission to the major population centre in southern Ontario.

In addition to the long distance to the southern Ontario load centre, recent Ontario government policy has strongly favoured in-province generation. The Ontario *Green Energy Act* of 2009 created strong incentives for renewable generation located within Ontario, including guaranteed payment (a feed-in-tariff) of $115/MWh for wind power and from $347-$549/ MWh for solar power[6].

The contracts OPA has entered into for nuclear power, gas-fired generation, and renewables under the Act have resulted in an energy surcharge, called the "Global Adjustment", on top of the Ontario electricity market price, which is actually greater than the cost of market energy itself[7]. Manitoba Hydro is not eligible for revenue from the global adjustment since its generation sources are located outside of Ontario; therefore, Manitoba Hydro is at a significant competitive disadvantage in selling into Ontario.

5.4.3.2 Saskatchewan Bilateral Market

Saskatchewan, like Manitoba, does not operate an energy market within the province. SaskPower is the principal electricity provider in Saskatchewan and has the exclusive right and obligation to supply electricity to the province, except the cities of Swift Current and most of the city of Saskatoon. SaskPower is owned by the government of Saskatchewan through its holding company, the Crown Investments Corporation. Through its wholly-owned subsidiary,

[6] Ontario FIT/mFIT PRICE SCHEDULE dated April 5, 2012.
[7] Ontario Power Authority, Outlook for Electricity Demand and Supply in Ontario, November 6, 2012

NorthPoint Energy Solutions Inc. (NorthPoint), SaskPower engages in the purchase and sale of energy in the North American wholesale market.

SaskPower's peak load in January 2012 was 3,265 MW; at the end of 2011, SaskPower's total available generation capacity was 4,094 MW. SaskPower expects load growth over the next decade of 2.9% per year in system energy and 2.5% per year in system peak, an increase from the 2000-2010 period when system energy requirements increased 1.4% per year and system peak load increased 1.1% per year[8].

Over the last decade SaskPower has built or purchased the output of over 800 MW of natural gas-fired generation and 200 MW of wind generation. Saskatchewan is Canada's third-largest producer of natural gas—producing 220 billion cubic feet of natural gas worth almost $500 million[9] in 2011—and possesses a good wind resource. Manitoba Hydro and SaskPower are in continuous contact to consider short- and long-term opportunities that could provide mutual benefits. In 2011 the provinces signed a Memorandum of Understanding (MOU) which included the intention to cooperate in areas of mutual benefit. In July 2013, SaskPower and Manitoba Hydro developed a MOU to explore specific initiatives. Under the MOU the utilities are to engage in sale discussions for existing and new hydro exports to both northern and southern Saskatchewan—across all time-frames—for volumes ranging from 25 MW to 500 MW; discussions are also to include the possibility of new transmission interconnections.

5.4.3.3 Alberta Market

The Alberta Electric System Operator (AESO) is the independent system operator in Alberta and has overall responsibility for planning the transmission system. The AESO operates an energy-only real-time market as well as an ancillary services market comprised of regulating, spinning

[8] SaskPower 2013 General Rate Application, dated June 2012.
[9] Saskatchewan Resources Oil and Gas Fact Sheet, updated May 2012.

and supplemental reserves procured by the AESO and cleared through an on-line exchange. The overall AESO market design is similar to the MISO real time market design; however, Alberta lacks the day-ahead and capacity markets found in more advanced markets. The peak load in Alberta is around 10,000 MW, making the Alberta market one-tenth the size of the MISO market.

The Alberta market is not easily accessible to Manitoba Hydro—Alberta is not part of the Eastern Interconnection and the existing transmission interconnection between Saskatchewan and Alberta is only rated at 150 MW. Moreover, the existing transmission system through Saskatchewan itself is not designed for large east-west flows and there is no long-term surplus transmission within Saskatchewan available. Therefore, significant new sales into Alberta would require a major new transmission line from Manitoba to Alberta.

As Calgary is almost 50% further from Winnipeg than Minneapolis, and the MISO market overall is about 10 times the size of the Alberta market, from the Manitoba perspective transmission investment is better directed towards Minnesota and Wisconsin rather than Alberta. Since Alberta has substantial local reserves of natural gas and coal from which to provide its own fossil fuel, thermal generators in Alberta should have a lower cost of supply than other regions which may have to import thermal fuels.

5.5 Renewable Energy Credits

This section describes how additional value may be obtained from the positive environmental attributes associated with renewable energy. As previously noted in ***Chapter 3 – Trends and Factors Influencing North American Electricity Supply***, many U.S. states have enacted Renewable Portfolio Standards (RPS). The objectives vary from state to state and typically extend beyond simply increasing renewable energy to also include implicit, and sometimes explicit, objectives such as: promoting in-state jobs, providing rural economic development, enhancing energy security, promoting emerging technologies, and reducing GHG and other air

emissions and environmental effects. As such, the list of eligible technologies also varies from state to state and in many instances hydropower has been excluded. However, in recent years there has been a trend towards a much more inclusive treatment of hydropower. Minnesota's RPS includes hydropower from stations that have a rated capacity less than 100 MW. Starting in 2016, Wisconsin's RPS will include all hydropower facilities built after 2010.

A Renewable Energy Certificate (REC) can be issued for each MWh of renewable energy produced. Renewable tracking systems are in place to track RECs from the generator to load to demonstrate compliance with an RPS and to facilitate trading of renewable energy. A renewable generator can sell RECs along with the energy as a bundled product, or sell the energy and RECs separately as an unbundled product. The purchasers of the RECs can then use their ownership of the certificates to demonstrate compliance with the state RPS.

In addition to meeting state RPS requirements, there are parallel voluntary markets for RECs. Entities which place a high value on social responsibility and/or wish to demonstrate an environmentally positive brand image can participate in voluntary REC markets. The voluntary market for RECs is dominated by commercial and industrial customers. Residential customers may also participate indirectly in the REC market through local-utility green-pricing programs. A key requirement for REC sales in the voluntary market is that of third-party renewable energy verification provided by Ecologo (Canadian transactions) and Green-e (U.S. transactions). Ecologo and Green-e have specific criteria that a renewable generator must meet in order to qualify for certification or certifiable status; Manitoba's St. Leon and St. Joseph wind generators are Ecologo certified and Green-e certifiable. At the present time, Manitoba Hydro is selling RECs from the wind generation that it purchases, as well as some RECs from small hydro resources that meet Minnesota's 100 MW threshold. To date, the sale of unbundled RECs by Manitoba Hydro has been an additional source of revenue well worth pursuing, but is not expected to become a major source of revenue in the future.

RECs represent additional value above the market price of energy. As such Manitoba Hydro's long-term export price forecast does include the value of RECs. To the extent that RPS requirements include Canadian hydropower as an eligible resource, they could provide an additional incentive to buy electricity from Manitoba Hydro. The bundled RECs associated with hydropower are a key component of several of the newer long-term firm export sales. The value that Manitoba Hydro's export customers may derive from these RECs is embedded in the overall sale. While some of these bundled hydro RECs have value associated with RPS systems our customers have other needs for these RECs, such as to disclose what sources are serving their customers.

5.6 MISO Market Outlook

5.6.1 Need for New Generation Capacity

5.6.1.1 MISO's Independent Analysis

MISO annually prepares a regional transmission expansion plan, called the MTEP. MISO is not responsible for regional generation planning, (which is the responsibility of the individual utilities with oversight by the state regulatory bodies), and MISO does not prepare long-term electricity price forecasts. However, the transmission expansion plan must be consistent with individual-utility resource plans and MISO makes an extensive effort to produce a plan that is robust. The MTEP includes a regional load forecast and an indication of what new resources may be required. While MTEP 2012 is focused on justifying specific transmission projects within the MISO market footprint, it does provide some independent insights into future supply and demand in the MISO market.

The value of generation capacity can represent up to 30% of the total value of a long-term sale of capacity and dependable energy. At the present time, there is a surplus of generation

capacity in the MISO market footprint beyond that required to meet reliability/resource adequacy requirements; therefore, capacity prices are depressed. This surplus results from the rapid construction of natural gas resources during the mid-2000s coupled with the temporary halt in growth of demand following the 2008 economic downturn.

MTEP 2012 states that "the MISO region needs to add between 4,484 and 11,290 MW of new capacity, or 3,865 and 9,733 MW of demand reduction to meet minimum Planning Reserve Margins in 2022[10]". This need for new capacity is driven by two primary factors: gradual demand growth in the MISO market footprint, and pending generation retirements. New capacity is expected to be required to meet the forecast MISO demand between 2015 and 2019, depending upon MISO's planning assumptions[11].

5.6.1.2 Gradual Demand Growth

As part of the MTEP planning process, MISO prepared a regional demand forecast for the 2013 to 2022 period based on an aggregation of load-serving entity/utility peak demand forecasts. MTEP 2012 was initially based on a 2012 demand forecast of 97,408 MW with a compound annual growth rate of 0.91%—subsequent work modified the forecast slightly to a compound annual growth rate of 0.95%. MTEP 2012 also studied the effects of a high-demand growth rate future using a compound annual growth rate of 1.62%[12].

MISO's base-case demand-growth assumption in the range of 0.91-0.95% is consistent with the U.S. DOE's EIA 2013 Annual Energy Outlook (AEO 2013). AEO 2013 notes that growth in electricity use has slowed but is still expected to increase by 28% or 0.9% per year from 2011 to 2040[13]. The gradual load-growth finding is also consistent with the Brattle independent market

[10] MISO MTEP 2012, page 8.
[11] MISO MTEP 2012, Table 6.2-1: 2013-2022 Forecasted Reserve Scenarios, page 70.
[12] MISO MTEP 2012, page 72.
[13] U.S. DOE EIA AEO 2013, page 71. http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf

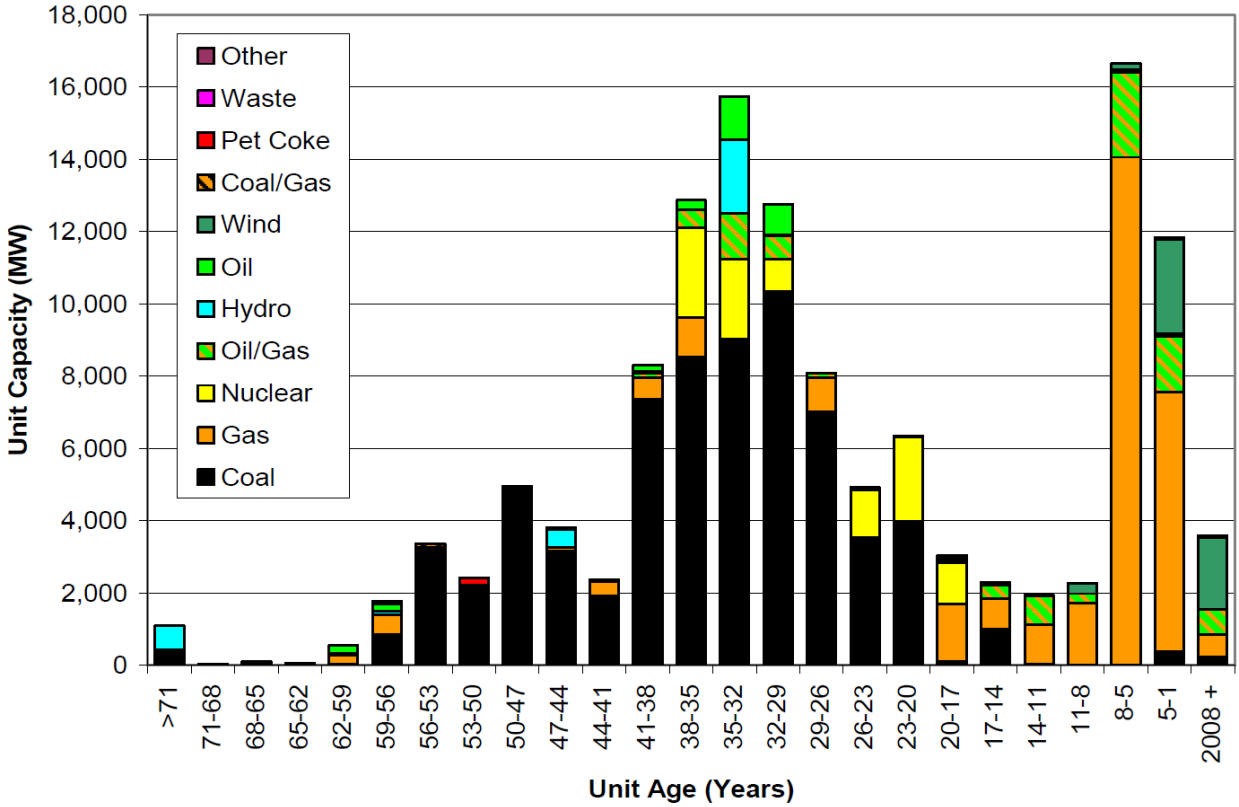
expert report— attached in ***Appendix 5.3 - Electricity Market Overview for Manitoba Hydro's Export Market in MISO.***

Gradual load growth in the MISO market footprint is expected to create a demand for new capacity resources.

5.6.1.3 Pending Generation Retirements

The vast majority of the 66,000 MW of coal-fired generation in the MISO market footprint is produced by generators over 25 years old as shown in Figure 5.14.

Figure 5.14 AGE OF MISO GENERATION FLEET IN 2010



About 20% of the MISO coal-generation fleet is over 45 years old. Older coal units tend to be smaller, less efficient and may have fewer existing emissions controls; these units are at risk of having to be retired due to a combination of factors:

- portion of key components including boiler, turbines and generators may require extensive refurbishment or replacement due to the number of operating hours
- U.S. EPA regulations may require significant upgrades of emissions controls. In particular the Mercury & Air Toxics Standard (MATS), designed to reduce the mercury emissions from coal-fired generating facilities by up to 90%, requires extensive new emissions-control equipment to be installed by 2015 or 2016; otherwise, the plant must be shut down
- the smaller size and lower efficiency of the units typically mean they are more expensive to operate—refurbishment and implementation of emission controls generally cost more per MW of capacity than for larger units.

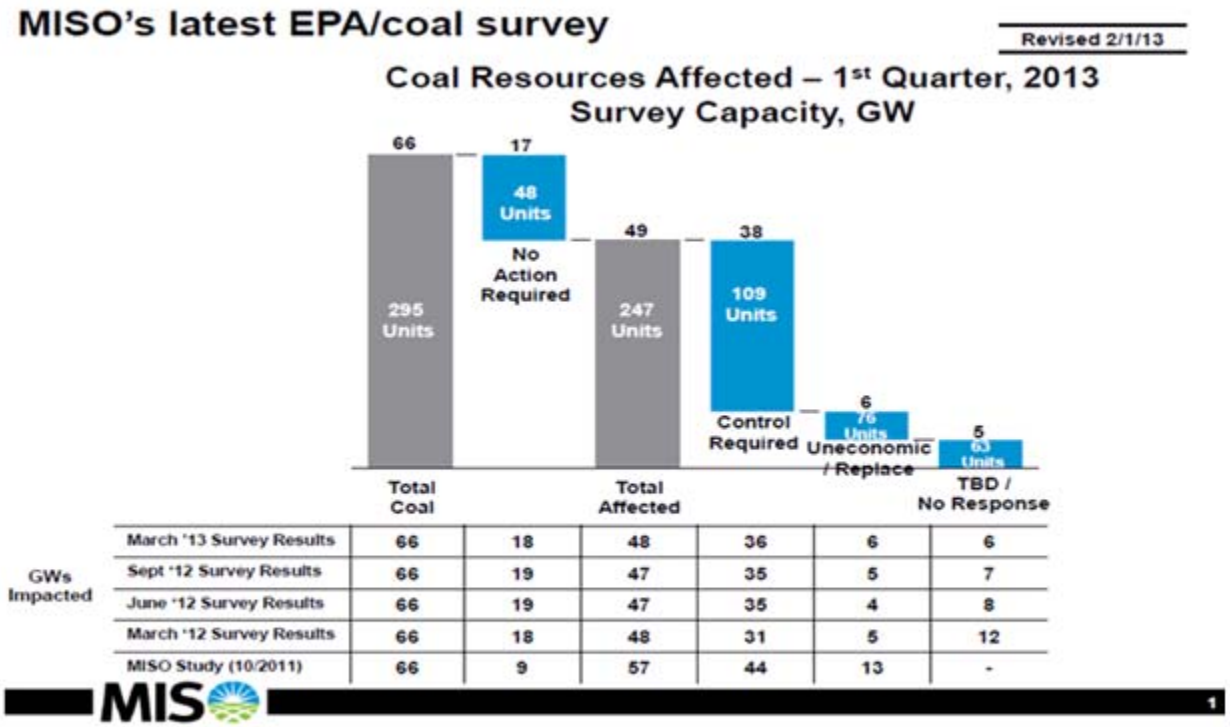
As a result, a number of coal-generating plants are expected to close, particularly older and smaller units. On a regional level, MISO has undertaken substantial analysis to estimate the magnitude and impact of coal retirements within its territory, including a quarterly survey which details how coal-generation unit operators expect to respond to EPA regulations. Figure 5.15 from the March 2013 MISO survey update, breaks down the projected impacts to the MISO coal fleet.[14] Based on the data, only 27% (18 GW) of MISO's coal fleet does not require any compliance measures to meet pending regulations. The majority of the fleet (36 GW) does require some new environmental controls and would be expected to implement and continue to operate these controls past 2016. Consequently, MISO estimates 6-12 GW of coal capacity will retire by 2020.

The survey supports the expectation that the coal units likely to retire are older, smaller units that currently have a low annual capacity factor, e.g. the most expensive and least-efficient coal units in the fleet. According to MISO, the average size of a coal unit that is expected to continue

[14] https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/EPA%20Compliance%20Update.pdf

operation is 350 MW, while the average size of a coal unit at risk of retirement is 80 MW—a finding that is consistent with the projected impacts across the U.S. This explains why the associated reduction in coal capacity (about 15% across the U.S.) will impact total generation share by a much lower magnitude.

Figure 5.15 ESTIMATED IMPACTS OF PENDING EPA ENVIRONMENTAL REGULATIONS ON MISO COAL GENERATION



NOTE:Survey results are for the MISO Market Footprint

In summary, coal retirements are expected to place upward pressure on electricity prices for both energy and capacity. Coal generation that is shut down would likely be replaced by natural gas-fired generation, resulting in natural gas generation—a more expensive product—setting a higher market price more frequently. In 2011, detailed analysis by MISO estimated that the cumulative impact of 12 GW in regional coal retirements would add an additional $5/MWh to the average on-peak market price for electricity.[15]

[15] https://www.midwestiso.org/Library/Repository/Study/MISO%20EPA%20Impact%20Analysis.pdf page 34

Coal generation closures will also advance the need for new generation capacity. Retired coal capacity will have to be replaced with other generation capacity to the extent necessary to maintain generation reserve margins, requiring new capital investment.

5.6.2 Long-Term Nuclear Uncertainty

As discussed in ***Chapter 3 – Trends and Factors Influencing North American Electricity Supply*** Section 3.5, the nuclear fleet in North America is aging, and existing nuclear plants may be expected to retire after about 60 years of service (after 40 years of operation under initial licence plus 20 years of licence extension). As shown in Table 5.14, the existing nuclear units within the MISO market footprint were placed into service between 1970 and 1985, and will reach 60 years of operation between 2030 and 2045. Some of these units may retire prior to 60 years of service particularly if major capital costs for refurbishment are required earlier. During 2013 four nuclear units across the U.S. with less than 40 years of service were permanently shutdown. This included the Kewaunee Power Station in Carlton, Wisconsin.

New supply will likely be required to replace these units, which operate at very high capacity factors, and are low carbon-emitting sources of supply. Such retirements of nuclear generation are likely to benefit Manitoba Hydro exports in the long term.

1 **Table 5.14** NUCLEAR POWER PLANTS IN THE MISO MARKET FOOTPRINT

Unit Name	Capacity	State	In-Service Year	Initial License Renewal Date	End of Extended License
Monticello	579 MW	MN	1970	2010	2030
Prairie Island 1	551 MW	MN	1974	2014	2034
Prairie Island 2	545 MW	MN	1974	2014	2034
Kewaunee	556 MW	WI	1973	2013	Closed
Point Beach 1	512 MW	WI	1970	2010	2030
Point Beach 2	514 MW	WI	1973	2013	2033
Clinton	1,065 MW	IL	1984	2024	2044
Quad Cities 1	867 MW	IL	1972	2012	2032
Quad Cities 2	869 MW	IL	1972	2012	2032
Palisides	778 MW	MI	1971	2011	2031
Duane Arnold	640 MW	IA	1974	2014	2034
Fermi	1,122 MW	OH	1985	2025	2045
Callaway	1,236 MW	MO	1984	2024	2044
Cooper	830 MW	NE	1974	2014	2034