Table of Contents

This page is intentionally left blank.

3 Trends and Factors Influencing North American Electricity Supply

3.0 Chapter Overview

Manitoba Hydro's Preferred Development Plan is being advanced in the context of several notable trends and factors currently influencing electricity markets and resource decisions for new and existing generation. These trends affect both domestic and extra-provincial decisions for existing resources, the need for new generation, the costs of competing resources, and the market price that others are willing to pay for electricity exports. The need for new generation in the U.S. and Canada is being driven by:

- modest load growth
- an aging generation fleet
- uncertainty as to the life expectancy of nuclear plants
- various environmental and energy policies that could hasten the retirement of coal plants.

The chapter will focus on North American trends but will highlight information specific to the U.S. Midwest and Manitoba where available.

3.1 Introduction

Electricity demand in both Canada and the U.S. is expected to continue to increase over the 35-year planning horizon. The Energy Information Administration's (EIA) Annual Energy Outlook 2013 reference case projects overall U.S. load growth of 28% between 2011 and 2040 (0.9% per year).

Energy and environmental considerations and policies are and will continue to be major factors influencing resource choices and the market price for electricity. Global interest and attention to environmental issues and the effects of climate change are having an impact on the energy industry. Although the timing remains unclear, ultimately it is expected that concern over the impact of climate change will drive the implementation of legislation and regulation that will favor low or non-greenhouse gas (GHG) emitting generation sources, including hydro-electricity generated by Manitoba Hydro.

Recent developments in oil and gas extraction have significantly increased the availability of these resources. The growth of shale gas production (5% of U.S. gas production in 2006, up to 34% in 2011) has resulted in an abundant new U.S. supply source and has changed the long-term outlook for domestic natural gas prices. Most industry analysts foresee a range of potential prices with expected or reference cases that project moderate price growth over the next decade as marginal production costs rise and demand grows.

Regional electricity prices consist of the market price for energy, which includes the variable cost of generation, and value of capacity which reflects the capital cost of investing in new generation. Electricity prices have incorporated the effects of supply and demand, economic conditions, commodity prices and the impact of existing or potential energy and environmental policy. Based on these factors, electricity prices are expected to increase in real terms over the long-term.

Investment decisions in new generation are driven by a variety of factors, including capital costs, fuel costs (including long-term availability and cost volatility), and regulatory risks. In the U.S., constraints on new coal generation and the outlook for fuel prices support the expectation that natural gas will be the primary choice for new generation. However, natural gas is seen by many as a transitional fuel choice offering emission reductions relative to coal but still carrying a considerable GHG emission liability. Demand for long-term firm power sales by Manitoba Hydro's export customers demonstrates a trend towards choosing low and non-emitting resources, which are sheltered from the financial risks associated with potential GHG policy and regulation as well as the price uncertainty and potential volatility associated with natural gas.

The following sections will explore in more detail the trends and factors that are affecting electricity markets and driving resource decisions for new and existing electric generation.

3.2 North American Electric Load Growth

As shown in Figures 3.1 and 3.2 the demand for electricity has grown in Canada and the U.S. over the past 30 years. Electric load growth is influenced by a number of factors, including economic activity, population growth, technology development, end-use efficiency and industrial trends; several of these factors are considered below.

Recent years have demonstrated that the rate of load growth is declining, due largely to increasing energy efficiency and the migration of industrial processes out of North America. Periods of prolonged economic recession are evident in the historical load record, often showing up as periods of load loss. While the future will continue to witness periods of economic contraction, overall loads are projected to grow, albeit at a slower rate than historically observed. Table 3.1 provides North American Electric Reliability Council's (NERC) summer and winter projections of total annual demand growth across U.S. and Canadian regions. For most U.S. regions including Midcontinent Independent System Operator, Inc. (MISO) peak electric demand occurs in the summer, while Canadian regions are winter peaking. As demonstrated by the range of annual growth rates shown in Table 3.1, each jurisdiction is distinct and can be influenced by economic activity, population growth, technology development, end-use efficiency and industrial trends in unique ways. In a similar vein, annual growth rates vary depending on the factors being considered, methodology employed and time horizon.

Figure 3.1 HISTORIC NET ELECTRICITY CONSUMPTION IN CANADA[1]

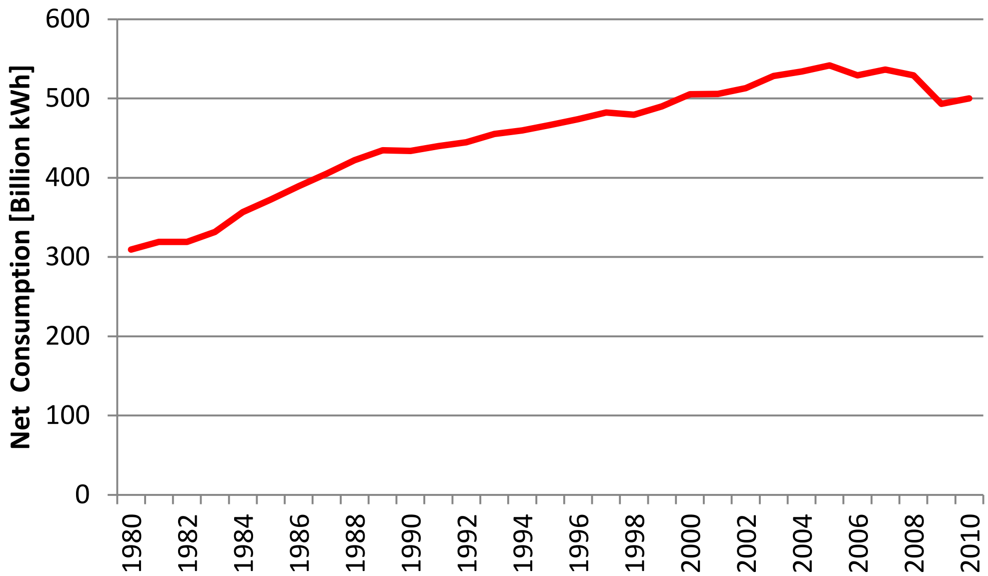
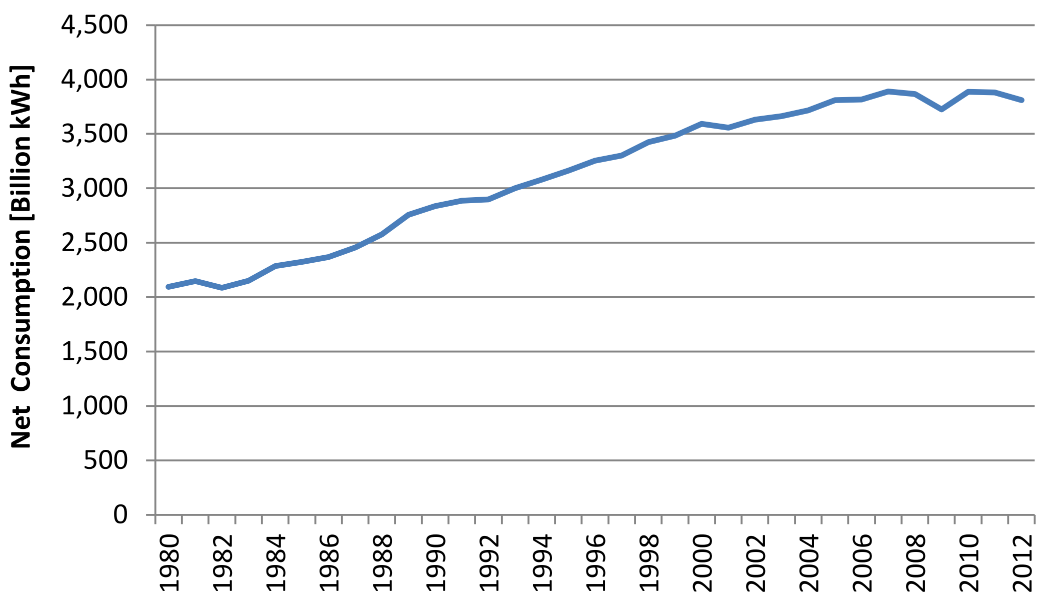


Figure 3.2 HISTORIC NET ELECTRICITY CONSUMPTION IN THE U.S.[2]



[1] U.S .Energy Information Administration. International Energy Statistics. Retrieved 08-Nov-2012: http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=2&pid=2&aid=2&cid=ww,r1,&syid=1980&eyid=2010&unit=BKWH

[2] 1980 – 2010 Data: U.S. Energy Information Administration. International Energy Statistics. Retrieved 08-Nov-2012: http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=2&pid=2&aid=2&cid=ww,r1,&syid=1980&eyid=2010&unit=BKWH
2011 – 2012 Data: U.S. Energy Information Administration. Short Term Energy Outlook Custom Table Builder. Retrieved 03-July-2013: http://www.eia.gov/forecasts/steo/query/

Table 3.1 COMPARISON OF ANNUAL TOTAL DEMAND GROWTH ACROSS REGIONS[3]

Annual Total Internal Demand				
	SUMMER		WINTER	
Assessment Area/ Country	10 Year Change (2013-2022)	Compound Annual Growth Rate (CAGR)	10 Year Change (2013-2022)	Compound Annual Growth Rate (CAGR)
ERCOT	23.3%	2.35%	22.4%	2.27%
FRCC	13.6%	1.43%	13.0%	1.37%
MISO	9.9%	1.05%	15.6%	1.62%
MRO-MAPP	20.4%	2.09%	21.6%	2.19%
NPCC - New England	13.8%	1.44%	5.2%	0.57%
NPCC - New York	7.5%	0.81%	3.9%	0.43%
PJM	12.9%	1.36%	10.6%	1.12%
SERC-E	11.4%	1.20%	11.0%	1.17%
SERC-N	13.7%	1.44%	13.6%	1.42%
SERC-SE	13.5%	1.42%	13.7%	1.43%
SERC-W	10.8%	1.15%	12.6%	1.33%
SPP	8.9%	0.95%	9.6%	1.03%
WECC-BASN	15.5%	1.62%	11.7%	1.24%
WECC-CALN	12.3%	1.29%	9.8%	1.05%
WECC-CALS	13.7%	1.44%	14.5%	1.52%
WECC-DSW	14.6%	1.53%	16.2%	1.69%
WECC-NORW	10.2%	1.08%	8.2%	0.88%
WECC-ROCK	15.7%	1.63%	17.2%	1.78%
TOTAL - U.S.	**13.0%**	**1.37%**	**12.6%**	**1.33%**
MRO-Manitoba Hydro	8.2%	0.88%	10.8%	1.14%
MRO-SaskPower	20.2%	2.07%	19.9%	2.04%
NPCC-Maritimes	2.3%	0.25%	2.4%	0.27%
NPCC-Ontario	0.6%	0.07%	-2.99%	-0.34%
NPCC-Quebec	8.1%	0.87%	7.3%	0.79%
WECC-AESO	38.3%	3.67%	37.1%	3.57%
WECC-BC	14.5%	1.51%	12.3%	1.30%
TOTAL -CANADA	**11.2%**	**1.19%**	**9.5%**	**1.01%**

Historically, electricity consumption has been associated with economic activity, as measured by real Gross Domestic Product (GDP). A growing economy is associated with increased

[3] 2012 NERC Long Term Reliability Assessment, Page 261

electricity consumption while economic downturns have a tendency to reduce or stall the growth of consumption. While the correlation between GDP and electricity consumption has been moderated by shifts away from manufactured goods and more towards services, the decrease in North American electricity consumption during the 2008–2009 economic recession demonstrates that overall economic conditions still have a significant impact on electricity consumption.

Figure 3.3 COMPARISON OF HISTORICAL REAL GDP (% CHANGE)[4]

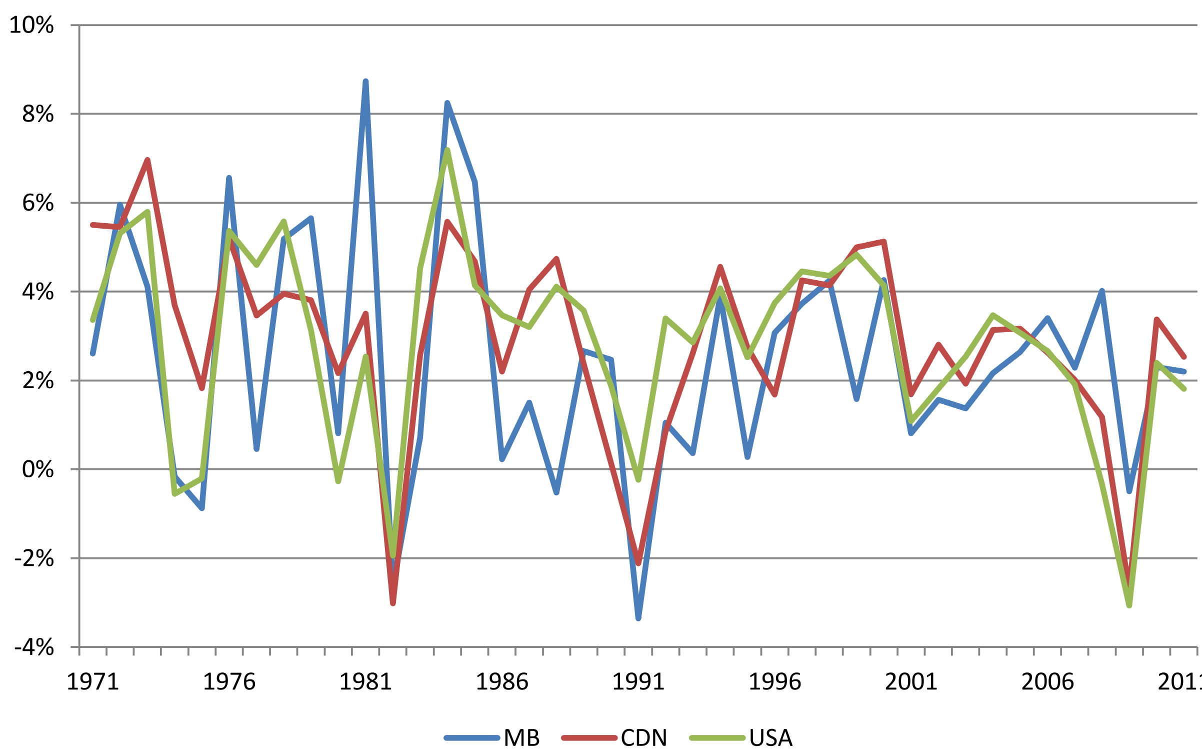


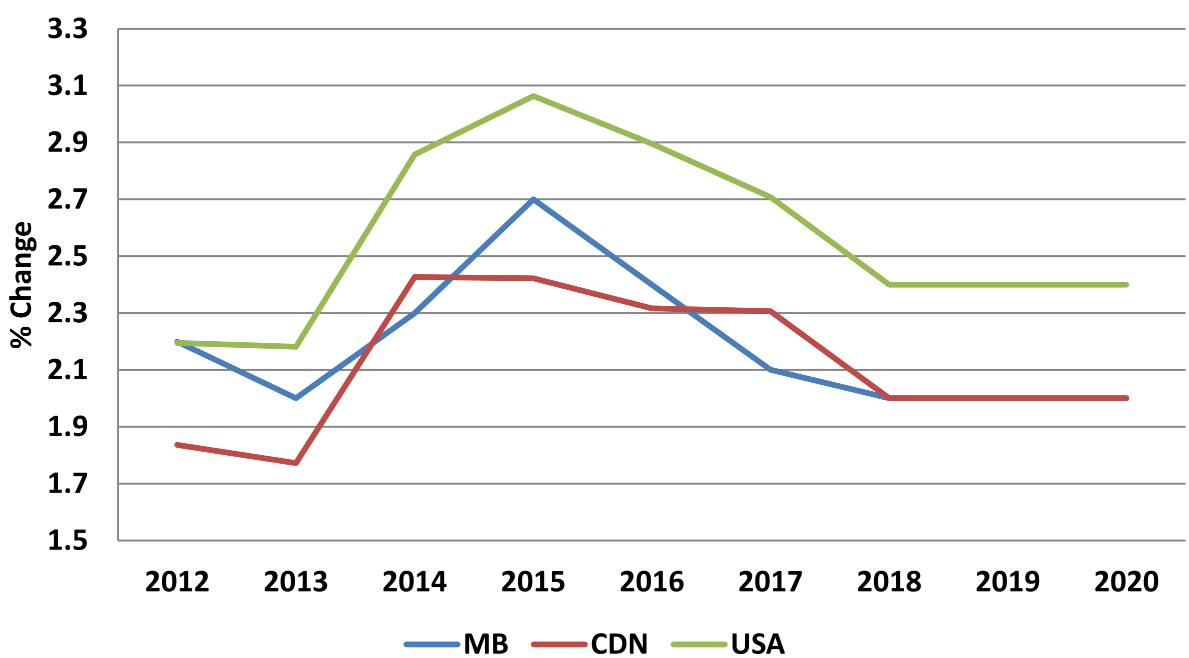
Figure 3.3 presents the historical real GDP variation for the Manitoba, Canada and U.S. economies. While economic growth is extremely variable, with periods of very high growth and periods of recession, in the long run these values have averaged around 2 to 3% growth per year. Global economic challenges remain (such as the continuing recession in Europe) and pose modest risks for the immediate short-term outlook for Manitoba, Canada and the U.S. This is

[4] From Manitoba Hydro's 2013 Economic Outlook

reflected in the modest economic growth projected for 2012 and 2013 shown in Figure 3.4. After 2013, forecasters anticipate slightly higher recovery-level growth before realigning with long-term average economic growth of between 2 to 3% per year. While economic growth is expected to continue to be volatile, the long-term average is expected to be consistent with the historic average.

Over the long physical lives of hydropower and transmission assets, several cycles of economic expansion and recession are anticipated. However, overall economic growth is anticipated to occur over the course of decades, requiring increased electricity supply as commercial and industrial economic activity expands. While investments in hydro-electric infrastructure may occur during times of recession, such long-term assets can accommodate short-term economic volatility.

Figure 3.4 COMPARISON OF FORECAST GDP (% CHANGE)[5]



There are also linkages between electricity prices and demand. Lower power prices tend to spur demand and reduce the incentive for efficiency, which over time puts upward pressure on

[5] From Manitoba Hydro's 2013 Economic Outlook

prices. Higher power prices, on the other hand, tend to do the opposite, spurring new supply and depressing demand, which in turn moderates those high power prices over time.

Population is another driver for electricity consumption. Both the Canadian and U.S. populations have experienced remarkable growth in the second half of the twentieth century. Over this period the American population doubled from a base of 151 million in 1950 to 309 million in 2010[6]. Similarly, the Canadian population grew by 165% from 12.3 million in 1946 to 32.6 million in 2006.

The U.S. Census Bureau projects that the U.S. population will continue to grow, although at a slower pace than during the past half century, to over 400 million persons by 2051[7]. Similarly, growth in Canada is expected to continue in the coming decades, with Canada's population projected to reach 42.5 million inhabitants in 2056 under Statistics Canada's medium growth scenario[8]. In Manitoba, the population grew from 800,000 in 1952 to 1.271 million in 2013. ***Appendix G - Economic Outlook 2013 - 2034*** projects that the Manitoba population will continue to grow to 1.585 million by 2034.

The growth in electricity demand has been moderated by the increasing implementation of energy efficiency technologies and practices. Utility-based demand side management programs, more stringent energy performance standards and technological improvements are all leading to efficiency gains that have moderated the rate of growth in electric demand.

While technology changes are delivering efficiency improvements they may also lead to new electrical load. Natural Resources Canada's Handbook on Energy Use shows that electrical energy used by refrigerators, freezers and dishwashers decreased between 1990 and 2009, while electrical energy used by small appliances and electronics (including televisions, video

[6] http://www.census.gov/prod/2011pubs/12statab/pop.pdf
[7] http://www.census.gov/newsroom/releases/archives/population/cb12-243.html
[8] http://www.statcan.gc.ca/pub/91-003-x/2007001/4129907-eng.htm#1

cassette recorders, digital video disc players, radios, computers and toasters) increased significantly. While home electronics, for example televisions, have become more efficient over time, they have also become more prevalent in homes, raising the total load. In the commercial and industrial sectors, the Handbook shows that overall electricity use increased for most industries while energy intensity decreased, pointing to improvements in efficiency.

Another example of a technology change that could increase electrical loads would be developments in battery technology that enable much greater adoption of plug-in hybrid or full-electric vehicles.

To conclude, electricity load growth is influenced by a number of factors, including economic activity, population growth, technology development, end-use efficiency and industrial trends. Overall economic activity adds variability to load growth and has most recently resulted in load reductions. However, the electric load is expected to grow in both Canada and the U.S. over the planning horizon. The EIA Annual Energy Outlook 2013 reference case projects overall U.S. load growth of 28% between 2011 and 2040 (0.9% per year).

3.3 Energy and Environmental Policies

Energy and environmental policies represent major factors influencing resource choices and the market price for electricity. Governments are implementing environmental policies that have been shaping the electricity industry for decades. The interest in environmental policies is driven by concerns for the immediate effects on both the biophysical and socio-economic components of the environment, implications for human health and the long-term sustainability of the environment including climate change.

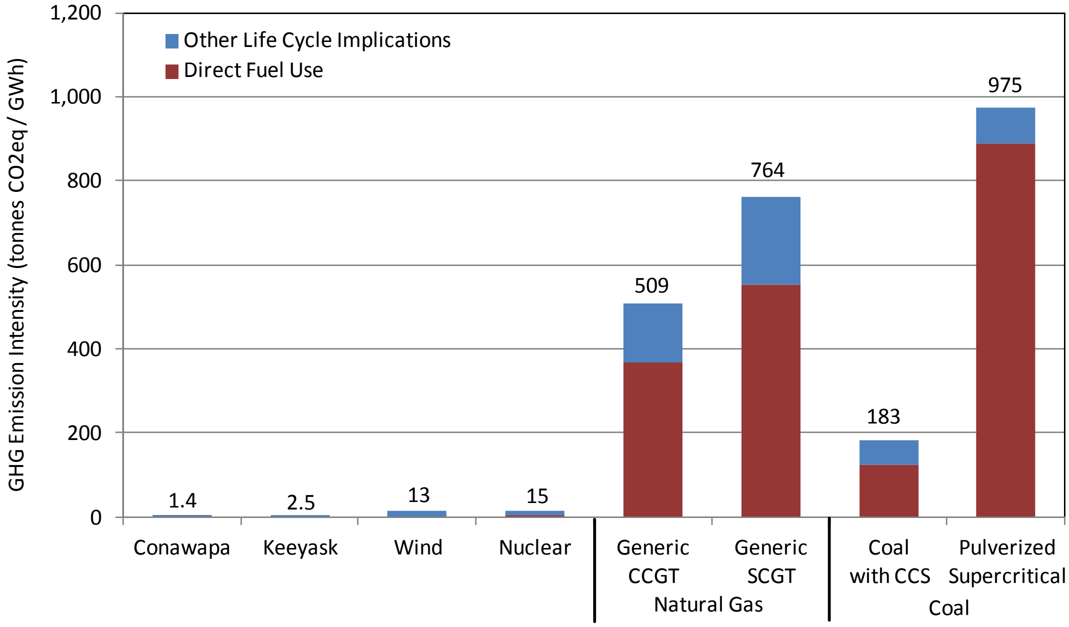
North American initiatives related to air quality have been in place for decades. For example, the U.S. Acid Rain program was introduced in the 1990s under the Clean Air Act Amendments and resulted in reductions in sulphur dioxide (SO_2) emissions of 50% from 1980 levels. Current North American environmental policy priorities focus on continuing to improve air quality by further reducing emissions of SO_2, nitrogen oxides, fine particulates and mercury as well as reducing GHG emissions.

Addressing climate change poses a daunting challenge. Climate change has been the focus of international, national and provincial/state policy development for over 20 years, and represents a potential driver for market price increases and for long-term changes in the composition of the energy mix.

The electricity sector presents an opportunity to reduce GHG emissions because it is responsible for a significant proportion of national emissions (33% of emissions in the U.S.[9] and 13%[10] in Canada in 2011) and because there are a variety of alternatives to fossil fuel generation with very different GHG characteristics (see Figure 3.5). As a consequence, government policies are being considered to shift the generation mix over time toward low and non-emitting sources such as hydropower, nuclear, and other renewables. Figure 3.5, taken from ***Appendix 7.3 – Life Cycle Greenhouse Gas Assessment Overview*** compares the lifecycle GHG emissions of several generation types.

[9] http://www.epa.gov/climatechange/ghgemissions/sources.html
[10] http://www.ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=F60DB708-1

Figure 3.5 COMPARISON OF LIFECYCLE GHG EMISSIONS FOR ELECTRICITY GENERATION[11]



Several states and provinces are now implementing carbon pricing policies. Such carbon pricing systems have the effect of adding to the cost of fossil-fueled generation, increasing the market price of electricity and improving the relative economic attractiveness of low and non-emitting resources.

In the following sections, energy and environmental policies are reviewed from global, U.S., Canadian, state and provincial perspectives.

3.3.1 Global Perspective

Activities which address climate change have been an ongoing priority for more than two decades. In 1992, countries around the world joined a treaty called the United Nations Framework Convention on Climate Change (UNFCCC) to discuss how to limit global temperature increases through the reduction of GHG emissions. In 1995 countries launched into

[11] Appendix 7.3 – Life Cycle Greenhouse Gas Assessment Overview

negotiations to strengthen this treaty recognizing that emission-reduction provisions needed to be mandated: the Kyoto Protocol was born out of these negotiations and was signed into effect in 1997. The Kyoto Protocol was the first treaty that legally bound many countries to meet GHG emission reduction targets. While both Canada and the U.S. signed the Kyoto Protocol, the U.S. did not ratify the Protocol. Canada ratified the Protocol but withdrew from it in 2012. Though Canada and the U.S. are not formally bound by the Kyoto Protocol, both countries continue to participate in global climate change policy discussions and emission reporting as parties to the UNFCCC.

The 15th Conference of the Parties to the UNFCCC took place in Copenhagen in 2009 and resulted in the Copenhagen Accord (Accord). While not legally binding, the Accord sets emission reduction targets to limit global temperature increases to 2 degrees Celsius or less, and emphasizes the "strong political will to urgently combat climate change in accordance with the principle of common but differentiated responsibilities and respective capabilities." The Accord recognizes the scientific view that an increase in global temperature be limited to 2 degrees Celsius (from pre-industrial times) in order to "stabilize GHG concentration in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[12]

The Government of Canada affirms that the Accord "reflects Canada's long-standing position that real progress on climate change requires a global agreement that includes all major emitters." [13] Under the Accord, Canada and the U.S. both committed to emission reductions of 17% below 2005 levels by 2020. In comparison, countries in the European Union (EU) committed to reduce emissions by 20 to 30% below 1990 levels, Australia committed to reductions between 5 and 25% below 2000 levels and China committed to a carbon intensity (emissions per unit GDP) reduction of 40 to 45% below 2005 levels (all targets by 2020).

[12] http://unfccc.int/resource/docs/2009/cop15/eng/l07.pdf
[13] http://climatechange.gc.ca/cdp15-cop15/default.asp?lang=En&n=970E8B07-1

Countries have adopted several strategies to reduce GHG emissions. The EU countries created the European Union Emissions Trading System (EU-ETS). This system was launched in 2005 and covers emissions from more than 12,000 power plants, airlines and factories operating in 31 different countries accounting for approximately 45% of EU GHG emissions. The goal of the EU-ETS is to reduce emissions from covered sectors by 21% below 2005 levels by 2020. Though the EU's overall GHG emissions have continued to drop, the EU-ETS has been fraught with problems related to a growing surplus of emission allowances due to an initial over-allocation exacerbated by the economic crisis. The European Commission is debating potential changes to the structure of the EU-ETS in order to provide a longer-term solution to the surplus of allowances. Some European countries have adopted further GHG pricing policies in addition to the EU-ETS. For example, Sweden uses a variety of GHG-based taxes to encourage emission reductions from segments of the economy not covered by the EU-ETS and in some cases to incent further reductions from sectors that are covered.

On July 1, 2012 Australia implemented a carbon tax of $23/tonne which was planned to rise by 2.5% per year before transitioning to a flexible price determined by the market under an emission trading scheme linked internationally with the EU-ETS in 2015. In an effort to "bring Australia into step with its major trading partners" [14] and respond to domestic consumer and business concerns ahead of upcoming elections, Australia's Prime Minister announced in July, 2013 that the carbon tax would transition to a market-based price in 2014 – one year ahead of schedule.

New Zealand has also implemented an Emissions Trading Scheme. Emission units can be purchased from the New Zealand Government for $25/tonne or through international carbon markets at market prices.

[14] http://minister.innovation.gov.au/markbutler/MediaReleases/Pages/Australiatomovetoafloatingpriceoncarbonpollutionin2014.aspx

China has been active in creating "carbon credits" from emission-reduction projects through the Kyoto Protocol's Clean Development Mechanism (CDM). China has over 1,560 projects registered with the CDM Executive Board, which account for 46% of total world-wide projects. Recently, China initiated a number of regional pilots to test carbon trading domestically as a potential precursor to developing a country-wide cap-and-trade scheme.

While a global emissions treaty was originally thought of as the first step towards international emission reductions it now appears that differentiated actions by individual countries may be an important precursor to a binding global treaty. Many developed countries are providing leadership in managing GHG emissions through their individual efforts. The inclusion of the world's largest emitters among the emerging economies, e.g. China, will also be critical in developing a binding international approach.

3.3.2 U.S. National Policy Perspective

Addressing climate change has been a focus of the U.S. since 1992 when President George H.W. Bush signed onto the UNFCCC. It remained a priority under President Bill Clinton who signed onto the Kyoto Protocol in 1997. Congress subsequently rejected the ratification of the protocol largely on the grounds that it did not include emissions reduction targets for the high-emitting emerging economies like China, India and Brazil. President George W. Bush later pursued reductions of other air emissions and technologies that his administration perceived would enable subsequent GHG emission reductions. Congress, meanwhile, has been confronted by several bipartisan cap-and-trade bills. Subsequent to the election of President Barack Obama and the onset of the U.S. recession, national economy-wide legislative action on climate change is now perceived to be a Democratic issue with little visible bipartisan support. President Obama has encouraged the U.S. Congress to consider renewable or clean energy standards, although it is considered unlikely that this type of policy will pass into federal law in the near term. Dealing with climate change is a difficult issue for politicians to grapple with since it pits perceptions of more immediate negative economic consequences against a range of potential long-term climate change consequences. Federal legislative action will require a more constructive political environment, overwhelming public support, or sufficient state level action to warrant harmonization under federal law. In the absence of these conditions, the President Obama's Administration is using its regulatory authority, primarily through the Environmental Protection Agency (EPA), to meet its energy and environmental objectives. President Obama reaffirmed this continued direction in the release of his "Climate Action Plan" in June, 2013.

The EPA has had regulations associated with air emissions in place for decades. For example, the Acid Rain Program, introduced under the 1990 Clean Air Act Amendments, reduced SO_2 emissions by 50% from 1980 levels. The EPA is currently developing further regulations on environmental impacts, including GHG emissions, hazardous air pollutants (such as mercury and acid gases) and other impacts to air quality.

Because of its GHG and other environmental implications, the electricity sector, in particular coal-fired generation, is a focus of several proposed regulations. These regulations could preclude the development of new conventional coal generation (i.e. without carbon capture and storage technology), accelerate retirements of existing generating stations and in the long-term markedly reduce the reliance on coal-fired generation.

The EPA is proposing that new fossil fuel-fired power plants greater than 25 MW meet an output-based standard which is comparable to the emissions of a new natural gas combined-cycle power plant. This standard effectively requires that new coal-fired generation have carbon capture and sequestration (CCS). Because the cost of CCS is currently prohibitive, the EPA proposal would effectively preclude construction of new coal plants. (Some research is still being done on CCS technologies. While a few heavily subsidized prototype installations exist, these technologies are not mature.) The EPA is also considering similar GHG performance standards for existing power plants, although such regulation is still at the conceptual stage and would face more opposition than performance standards for new sources.

The most significant of the EPA's several non-GHG regulations is the Mercury and Air Toxic Standards (MATS) rule for coal- and oil-fired power plants. The MATS rule is a firm end-of-pipe emissions control limit designed to reduce mercury and other hazardous air pollutants (such as acid gases) from coal-fired and oil-fired plants by up to 90%. Plants will need to achieve those emission limits by April 2015, with a 1-year extension that can be issued by state-permitting agencies (and a possible additional 1-year extension from the EPA to prevent grid reliability concerns). The MATS rule is final for existing and new plants as of April 2013, though it will likely still face legal challenge. The majority of existing coal units in the U.S. and more specifically within MISO will be affected by the MATS rule, meaning that they will be required to add pollution control equipment to comply. Estimates from MISO indicate that anywhere from 6 GW (gigawatt) to 12 GW of coal capacity will retire by the end of the current decade.

The EPA has also proposed several other regulations that affect fossil-fueled generation, such as handling of coal combustion residuals (CCRs) and cooling water intake structures. The proposed CCR rule includes two options, both of which would likely result in eliminating wet ash ponds or converting to dry landfills for most plants by the end of this decade. In addition, the proposed rule will likely require dry collection systems for bottom ash and fly ash. The proposed rule on cooling water intake structures aims to reduce injury and death of fish and aquatic life. The EPA proposes that each state-permitting agency decide on the required control technology for each covered plant on a case-by-case basis, and these controls may include a combination of modified moving screens and cooling towers.

With respect to natural gas extraction, the agency also faces some important decisions with the regulation of hydraulic fracturing. The EPA is engaged in a study of hydraulic fracturing to assess potential impacts on drinking water; this is expected to be released for public comment in 2014. In the meantime, some states have imposed moratoriums on hydraulic fracturing until they have the opportunity to consider the impact of the EPA's findings. The results of this EPA study could determine the extent to which the more stringent regulations may be imposed on hydraulic fracturing, which could potentially restrict the overall availability and correspondingly the price of natural gas.

Cumulatively, emerging EPA regulations are requiring generators to decide whether to invest large amounts of capital for additional environmental controls on existing coal generating plants in an environment of lower power prices and potential GHG liabilities, or to retire the plants within the next few years (see section 3.5 Aging Generation Fleet).

3.3.3 Canadian National Policy Perspective

From a GHG perspective, both Canada and the U.S. are committed to emission reduction targets of 17% below 2005 levels by 2020. While the Canadian Government is not currently pursuing an economy-wide carbon-pricing mechanism, it is taking regulatory actions to address GHG emission on a sector-by-sector basis. The Government estimates that through federal and provincial measures, Canada is halfway towards meeting its 2020 GHG emission reduction target.

In 2010 Environment Canada released regulations aimed to reduce emissions from the transportation sector. In 2012 Environment Canada released a plan to reduce GHG emissions from aviation, followed by the release of final regulations to reduce GHG emissions from coal-fired electricity generation. The latter regulation effectively requires new coal plants built after July 1, 2015 to meet a GHG emission standard comparable to that of a combined-cycle natural gas generator. Existing coal units older than 50 years of age would also be required to meet this standard. Since typical units cannot meet such a standard, the regulation effectively requires the phase-out of conventional coal through the addition of carbon capture and sequestration, switching to a non-coal fuel, or retirement. Environment Canada is negotiating equivalency agreements with provincial governments on a case-by-case basis, under which provinces can justify an equivalent environment outcome.

Environment Canada has announced it is working on regulations for other activities including natural gas generation and oil and gas sectors. However, as of June 2013, little is known about what specific form these regulations might take.

Canada has also moved forward with a national Air Quality Management System (AQMS) for air pollutants. In October 2012, jurisdictions, with the exception of Québec, agreed to begin implementing the AQMS. New Canadian Ambient Air Quality Standards (CAAQS) will set the bar for outdoor air quality management across the country, and industrial emission requirements that set a base level of performance for major industries in Canada will be established. Standards for fine particulate matter and ground-level ozone have been developed and work has begun on standards for nitrogen dioxide and SO_2.

From a Federal Government policy perspective, it would appear that all sources of new generation are acceptable with the exception of conventional coal-fired generation primarily due to its high GHG emission implications.

3.3.4 State and Provincial Policy Perspectives

In addition to federal actions, state, provincial, and regional environmental policies with implications for the electricity sector are in various stages of implementation across North America.

The Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade program for the electricity sector in nine northeastern states. It took effect in January 2009 and originally called for a 10% reduction in GHG emissions from 2005 levels by 2018. Several amendments to the system rules were developed in 2013. The original system design was developed in 2005 and could not have anticipated the impact of natural gas price reductions or the economic downturn. As a result, there was an oversupply of program allowances. As the states remain committed to RGGI, a number of changes were made to the system including lowering the emissions cap by 45% in

2014 and cancelling unused 2012 and 2013 allowances. The first RGGI auction following the announced changes to the model resulted in a clearing price of $2.80/short tonne, up appreciably from the previous auction but still at level too low to drive meaningful emission reductions.

To reduce GHG emissions, California and Quebec have also launched cap-and-trade programs under the Western Climate Initiative. The cap-and-trade programs initially cover emissions from electricity generation, industrial facilities and fuel distributors with annual emissions greater than 25,000 tonnes carbon dioxide equivalent (CO_{2e}). In 2015, both programs plan to double in scope to cover emissions from transportation, residential and commercial fuels. In 2015 California's program plans expand to cover 85% of state emissions. Similarly, Quebec's program would expand to cover 75% of provincial emissions in 2015. Entities will be expected to lower their emissions or purchase credits (through auction or trading). California's auction in May, 2013 saw allowances clear at a price of $14 USD/tonne. It has been announced that the two programs will be officially linked to each other on January 1, 2014. Officials from California and Quebec have been advocating for the nine states covered by RGGI (an electric sector carbon market) to join their economy-wide cap-and-trade system.

Some provinces have opted to implement alternatives to cap-and-trade initiatives that still deliver carbon pricing such as the revenue-neutral carbon tax that British Columbia introduced in July 2008. This tax applies generally to all fossil fuels across the economy. The tax rate was originally set at $20/tonne of ($CO_{2e}$) equivalent and increased over five years to the current $30/tonne. The current Liberal government promised during their 2013 election campaign to freeze the carbon tax for the next five years to provide time for other jurisdictions to catch up.

Manitoba also has a carbon tax solely on coal. *The Emissions Tax on Coal Act* came into effect on January 1, 2012 and requires that purchases of coal for use in Manitoba must pay an emissions tax: this tax is roughly equivalent to $10/tonne of CO_2.

Alberta's emission intensity system is also delivering a modest carbon price under its *Climate Change and Emissions Management Amendment Act* and its accompanying Specified Gas Emitters Regulation which came into effect on July 1, 2007. Facilities that emit more than 100,000 tonnes of GHGs per year are required to reduce their emission intensity (GHGs per unit of production). Companies may reduce their emissions by increasing efficiency, buying Alberta-based carbon offsets, trading with other companies, or by paying $15/tonne ($CO_2$) into a provincial technology fund.

Some provinces have also implemented regulatory approaches to reduce emissions such as Manitoba's Coal-Fired Emergency Operations Regulation, which came into force on January 1, 2010 under *The Climate Change and Emissions Reductions Act*. This regulation precludes coal-fired electricity generation except in support of emergency operations including drought. Ontario has a coal retirement mandate and recently announced plans to shut down its last two coal plants before 2014.

Further, some states have implemented licensing or regulatory requirements that make siting new coal-fired generation facilities very difficult if not impossible in these jurisdictions. For example, in 2007, Minnesota passed the *Next Generation Energy Act* which includes a section that addresses GHG emissions by prohibiting the construction of new generating facilities in the state that contribute to GHG emissions (including coal and natural gas-fired generation) unless the associated carbon emissions are offset. The Act also prohibits importing electricity generated outside of the state that would result in additional GHG emissions. The prohibition is in place until either Minnesota or the U.S. federal government adopts laws to specifically limit and "substantially reduce" the amount of allowable emissions. Shortly after the Act was passed, two key utilities withdrew their support for building the Big Stone II coal-fired power plant in neighbouring South Dakota, which was to export electricity to Minnesota, and the project was eventually cancelled. The State of North Dakota, which exports coal-fired generation to Minnesota, is currently challenging the law in federal court, raising constitutional and federal pre-emption issues.

Policies to encourage an increasing percentage of renewable energy within specific jurisdictions are widespread. As of March 2013, 29 U.S. states and the District of Columbia had enacted Renewable Portfolio Standards (RPS); several others had adopted non-binding renewable energy goals or targets[15]. The objectives vary from state to state and typically extend beyond simply increasing renewable energy to including implicit objectives such as: promoting in-state jobs, rural economic development, energy security, promotion of emerging technologies, and reducing GHG and other air emissions and environmental effects. As such, the list of eligible technologies 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 are less than 100 MW while Wisconsin's system will include all new hydro (starting in 2016 all hydro built after 2010 will be included). In Canada, three provinces have explicit RPS programs: Nova Scotia, New Brunswick, and Prince Edward Island. While there are differences, these programs generally include wind, tidal, biomass, solar and hydropower. Those provinces with significant hydro-electric generation already have very high proportions of renewable energy without the need for an RPS.

As an alternative or an addition to RPS policies, some provincial and state governments have also implemented other incentives to encourage renewable or emerging technologies such as biogas, renewable biomass, landfill gas, solar photovoltaic, water power and wind power. Examples include production tax credits and feed-in-tariffs. Feed-in-tariff prices are sometimes designed to cover project costs plus a return on investment for each type of technology, rather than delivering a common price signal to all project types. For example, in Ontario, photovoltaic projects may receive a tariff in excess of 50 ¢/kWh (kilowatt-hour), while wind power receives 11.5 ¢/kWh.

[15] http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf

Together, a patchwork of policies is emerging across states and provinces. While there are many differences between jurisdictions, there is a common trend towards policies designed to reduce various emissions, address climate change and increase the reliance on renewable generation. As economic conditions improve, other jurisdictions may join with the current leaders, possibly leading to the harmonization of regional approaches or a common federal approach.

3.4 Energy Price Considerations

A review of historical data illustrates that the average cost of fossil fuels has been the most influential determinant of market prices for electricity in the U.S. as conventional thermal generation is dominant in almost all regions; and even in regions with significant non-fossil generation, thermal generation is almost always the marginal, price-setting generation. Commodity prices for coal and natural gas determine dispatch order for existing units within a region (e.g. MISO) and directly relate to the resulting near-term electricity market price for energy. The impact that specific commodity prices have on the near-term market price for electricity can vary considerably across regions, depending on the resource mix.

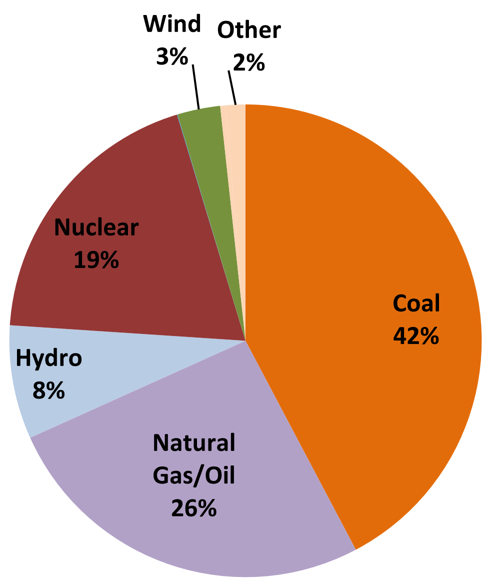
Although expectations of future fuel prices play a role in influencing investment choices, there are a myriad of considerations when planning for new generation. In addition to consideration of the type of resource needed (baseload, intermediate or peaking), factors influencing resource decisions include, but are not limited to, capital cost, electricity market prices, system reliability, fuel diversity, transmission requirements, corporate vision, and current and future environmental and energy policies.

The following sub-sections focus on the pricing implications for the primary fossil fuels that influence economic growth and electricity supply pricing within North America, and more specifically the MISO region.

3.4.1 Coal Pricing

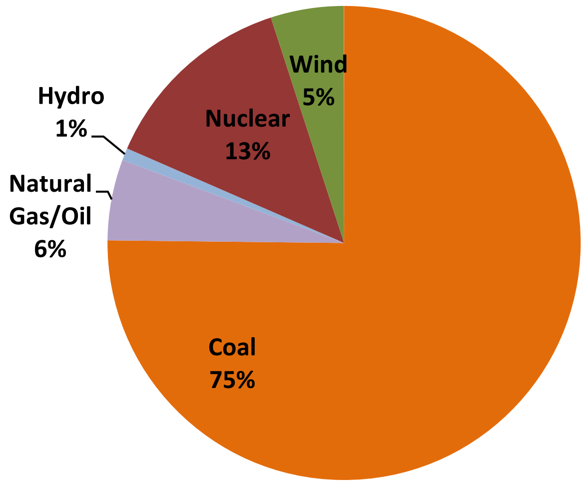
Due to its abundance, affordability and reliability, coal is one of the primary fossil fuels used for electricity generation both across the U.S. as a whole and within the MISO region. Figures 3.6 and 3.7 show the generation mix in the U.S. overall and MISO region by fuel type. Coal remains the dominant fuel for both the U.S. (42% of generation in 2011) and to a greater extent, the MISO region (75% of generation in 2011).

Figure 3.6 **2011 Generation Mix By Fuel Type – U.S.**[16]



[16] U.S. national level information based on: http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vud&geo=g&sec=g&freq=A&start=2001&end=2012&ctype=linechart&ltype=pin&pin=&rse=0&maptype=0

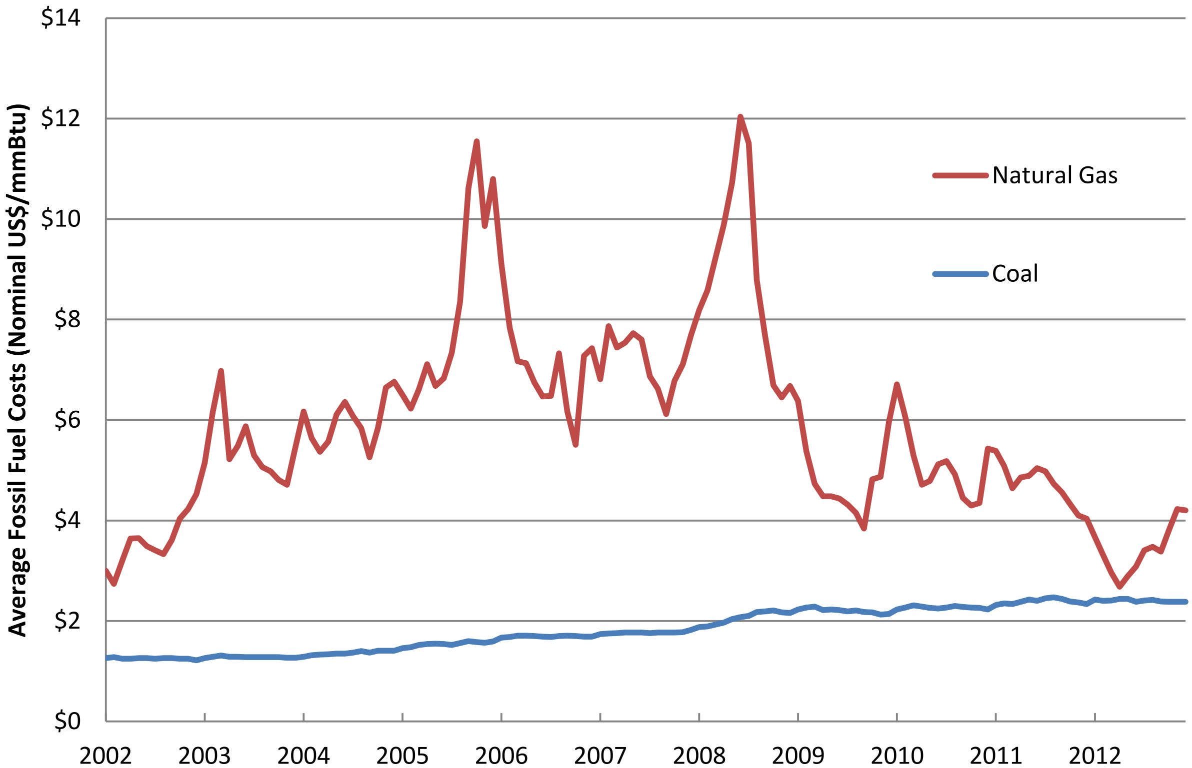
1 **Figure 3.7** **2011 Generation Mix by Fuel Type– MISO Region**[17]



2 Coal has a price advantage over other fossil fuels which is the primary reason it maintains its
3 dominance in the U.S. generation mix. Figure 3.8 provides a historical per-unit comparison of
4 the average delivered cost of fossil fuel for U.S. generators.

[17] MSO level information aggregated from monthly assessment reports: https://www.midwestiso.org/Library/Pages/ManagedFileSet.aspx?SetId=455

Figure 3.8 AVERAGE DELIVERED FOSSIL FUEL COSTS FOR U.S. GENERATORS[18]



Powder River Basin coal is the primary source of coal supply in the Midwest and its prices have been lower and more stable relative to coal resources in other regions. Although ample supply is available, prices are expected to increase moderately over time, due to higher extraction and environmental compliance costs. The EIA projects real escalation for U.S. coal prices in the order of 1.4% per year to 2040.[19]

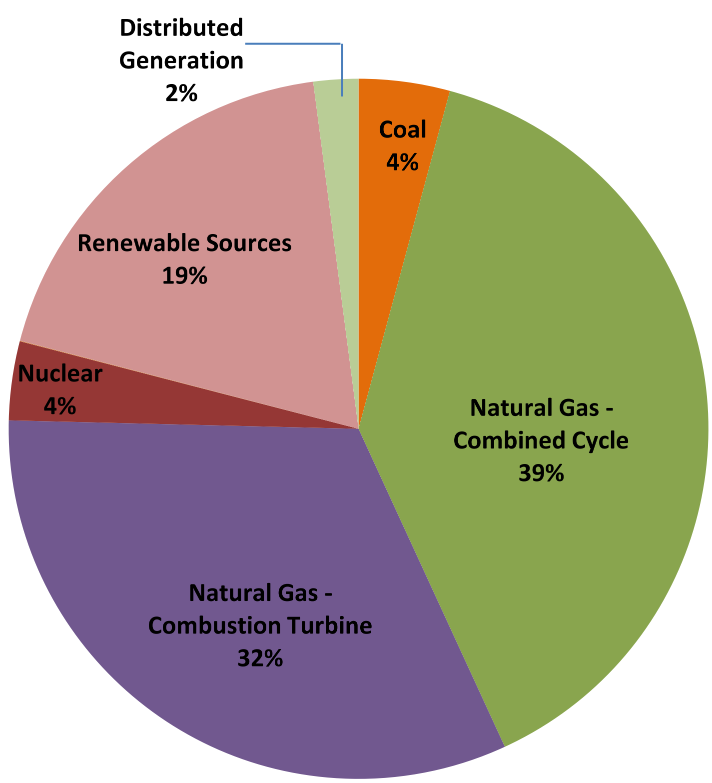
In the absence of additional stringent coal regulations or very high carbon prices, the EIA is projecting coal to generate a high proportion of electricity within U.S. and particularly in the Midwest through 2030.[20]

[18] http://www.eia.gov/forecasts/steo/query/. Frequency = Monthly. Year Range = 2002 to 2012.Select U.S. Natural Gas -> Prices -> Electric Power Sector -> U.S. Average; U.S. Coal -> Prices -> Cost to Electric Power Sector.
[19] http://www.eia.gov/oiaf/aeo/tablebrowser/
[20] http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=6AEO2013&table=63AEO2013&region=0-0&cases=ref2013-d102312a

3.4.2 Natural Gas Pricing

Natural gas availability and pricing are two of the most important considerations driving electrical resource decisions and market prices for electricity. The recent increases in availability of natural gas and associated reductions in cost, due to the recent developments in shale gas extraction, have increased its attractiveness as a supply source. In addition, because of the proposed constraints on new conventional coal and forecasts for modest natural gas prices well into the future, natural gas is now expected to be the primary choice for new generation. As shown in Figure 3.9, the EIA projects that of the 151 GW of new generation capacity that is expected to be added in the U.S. by 2030, 71% will be natural gas-fired resources.[21]

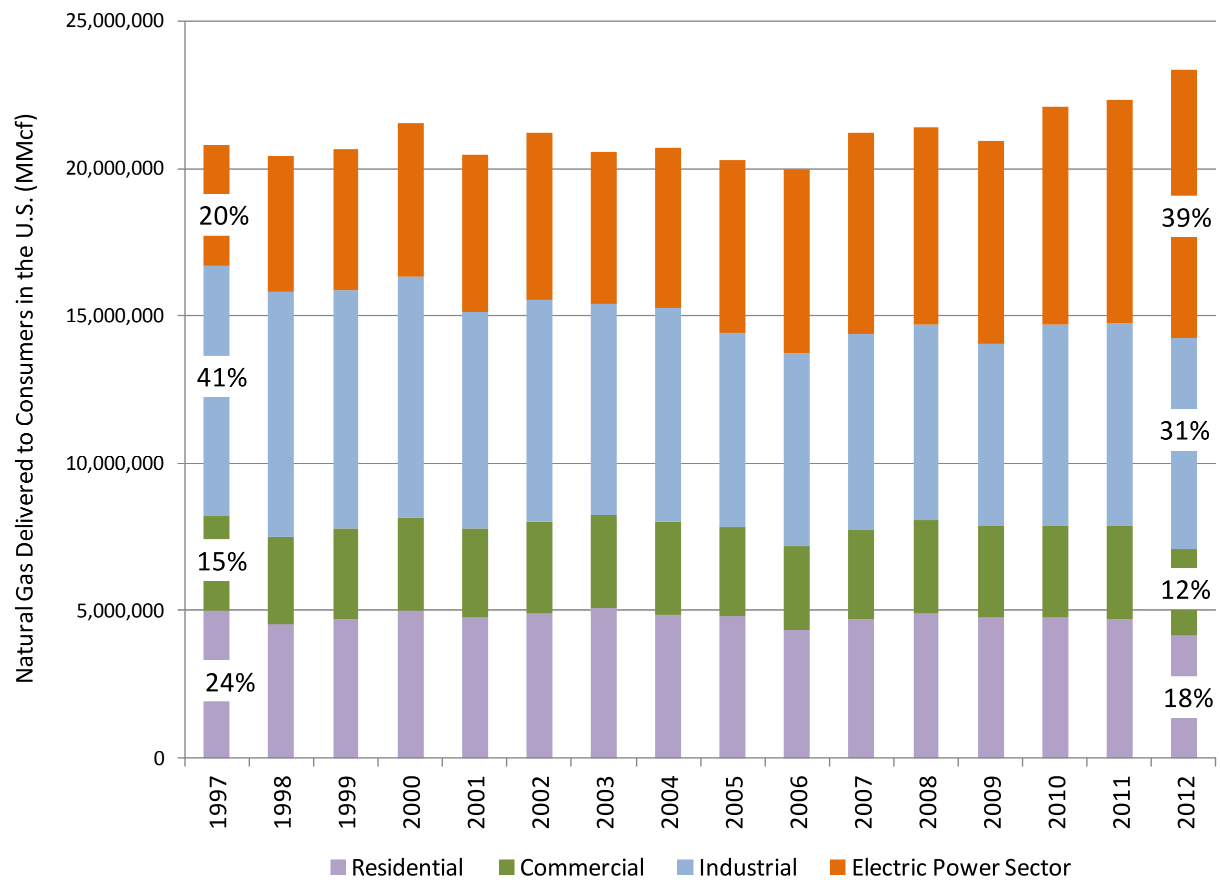
Figure 3.9 PROJECTED U.S. GENERATION CAPACITY ADDITIONS 2013 - 2030



[21]http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=6AEO2013&table=9AEO2013&region=0-0&cases=ref2013-d102312a

The growth in new gas generation capacity is not a new trend. Since 1995, natural gas generation has represented 84% of net capacity additions in the U.S. electricity sector. The historic build-out of gas resources resulted in a significant increase in annual use of natural gas by the electricity sector since the mid-1990s as can be seen in Figure 3.10. During this period, the percentage of total U.S. natural gas deliveries to the electricity sector has doubled, from 20% in 1997 to 39% by 2012. In fact, the residential, commercial and industrial sectors all saw a decline in physical gas deliveries during this period by 10-15%, while the electricity sector's physical deliveries increased by 125%.

Figure 3.10 HISTORIC U.S. NATURAL GAS CONSUMPTION BY END USE



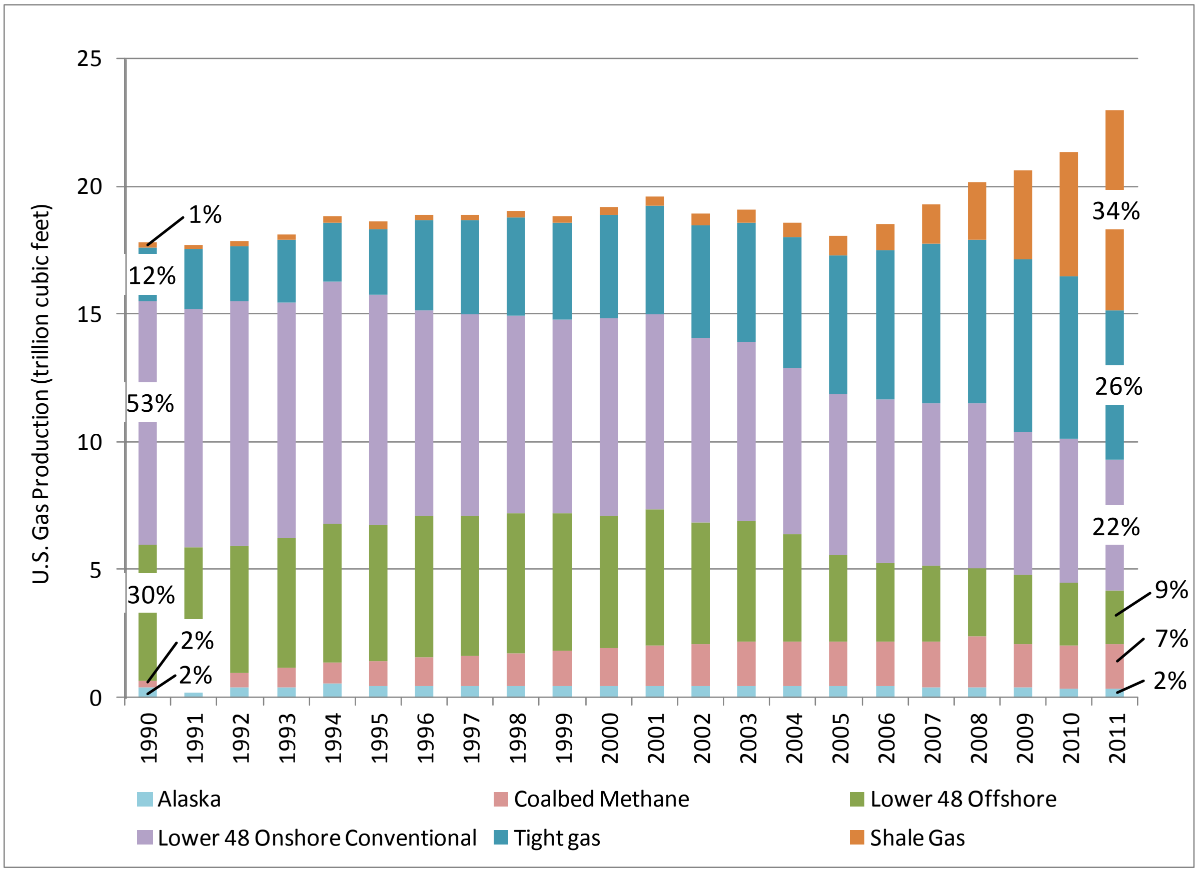
Source: Energy Information Administration

In terms of supply, recent production breakthroughs resulting from technological advances in the processes of horizontal drilling and hydraulic fracturing of shale gas fields in the U.S. have had a dramatic impact on natural gas reserves and production. Proven reserves of natural gas in the U.S. are now exceeding levels of the 1960s and 1970s, with shale gas representing much of this growth.

The availability of shale gas has resulted in significant increases in the production of natural gas in the U.S. In the early 2000s, growth in gas consumption from the power sector and declining conventional production sources were combining to drive up gas prices. Due to lack of available economic domestic sources, liquid natural gas (LNG) import terminals were being planned and constructed to meet the growing U.S. demand. However in the mid-2000s, unconventional resources started coming on stream and quickly picked up the production shortfall. In only five years shale gas went from representing 5% to 34% of U.S. dry gas production (See Figure 3.11). Total U.S. production has grown at 4% per year since 2006, and is expected to reach 25 trillion cubic feet per year by 2016[22]. As a result the EIA now projects the U.S. to be a net natural gas exporter by 2020[23], with LNG terminals to access world markets, supplementing existing pipeline interconnections with Mexico, Canada and Bahamas.

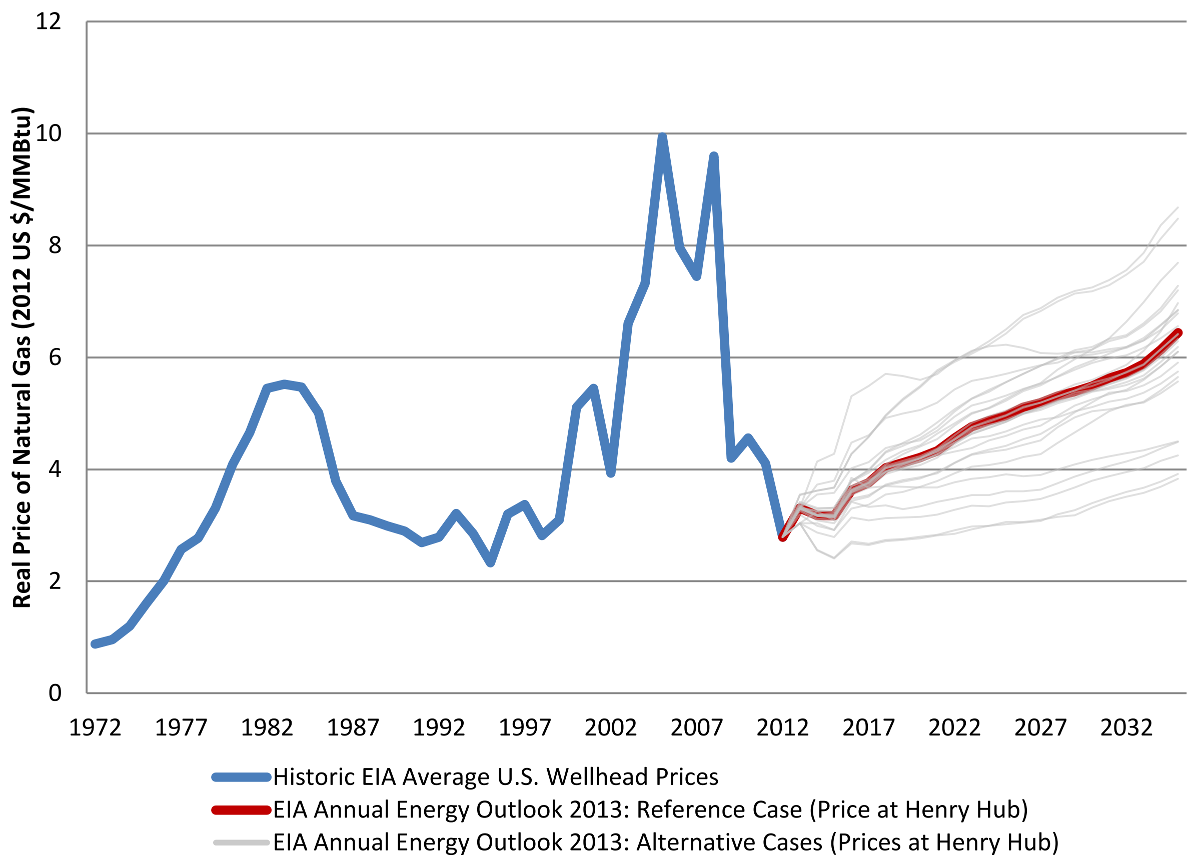
[22] 2013 EIA Annual Energy Outlook. (Figure 91 - http://www.eia.gov/forecasts/aeo/source_natural_gas_all.cfm)
[23]http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=8-AEO2013&table=76-AEO2013&region=0-0&cases=ref2013-d102312a

Figure 3.11 HISTORIC U.S. NATURAL GAS PRODUCTION



Source: Energy Information Administration

Figure 3.12 HISTORICAL AND EIA PROJECTED REAL NATURAL GAS PRICES[24]



As shown in Figure 3.12 natural gas prices have exhibited considerable historical volatility. Declining conventional production in the mid-2000s, combined with growing demand, resulted in a severe escalation in prices with average U.S. wellhead prices topping $9.60/mmBTU (2012 USD) in 2008. However, the economic downturn in combination with new unconventional supply resulted in sharp price reductions in 2009. Prices then stabilized for about three years at around the $4/mmBTU mark until early 2012. A very mild 2011-2012 winter combined with continued growth in production resulted in an excess in natural gas supplies and record storage

[24] Historic 1972 – 2001 Average US Wellhead Prices retrieved from: http://www.eia.gov/dnav/ng/hist_xls/N9190US3a.xls. Historic 2002 - 2012 Henry Hub prices retrieved from: http://www.eia.gov/dnav/ng/hist_xls/RNGWHHDa.xls. Future EIA Annual Energy Outlook prices retrieved from: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=8-AEO2013&table=72-AEO2013&region=0-0&cases=ref2013-d102312a.
Historic and projected prices converted to 2012 USD using the implicit GDP deflator series retrieved from: http://www.bea.gov/iTable/iTable.cfm?ReqID=9&step=1#reqid=9&step=3&isuri=1&903=13 (Section 1, Table 1.1.9).

levels. In response to this over-supply the average price fell to $2.79/mmBTU in 2012. Over the summer months, increased utilization by the electric power sector (short-term fuel switching from coal to natural gas due to the extremely low natural gas prices) along with an eventual response in production supported a price recovery to the $4/mmBTU mark by spring 2013.

Unlike oil, the North American natural gas market is isolated from the higher-priced global natural gas markets because of the lack of liquid natural gas terminals and the associated export infrastructure. While the development of LNG export terminals is uncertain, they would allow the U.S. to leverage higher world prices.

In terms of projected natural gas prices, most industry analysts foresee a range of potential prices with expected or reference cases that project moderate real price growth from the current $4/mmBTU level over the next decade as marginal production costs rise and demand grows. Figure 3.12 demonstrates EIA's range of possible natural gas price outcomes: almost all of these price scenarios project real growth in prices. The EIA reference case projects that natural gas prices will escalate to about $5/mmBTU (in 2012$) by 2025, which is slightly pessimistic relative to most industry analyst price forecasts.

Future natural gas prices are uncertain and will be determined by many factors, including the cost of production, the balance of supply and demand and energy and environmental policies.

It is recognized that there are feedback loops associated with fuel supply and pricing. When in over-supply, low prices provide an incentive for increased demand and reduced efficiencies. Under-supply and high prices would have the opposite effect. Currently a low-priced environment prevails and there are indications of increased pressures on demand, supply and price.

New incremental demand may arise from increased natural gas utilization by the electricity sector due to coal retirements, increased LNG exports, increased use of natural gas for space heating and in transportation, and potential increases in North American industrial demand due to lower prices. Currently the high prices for natural gas liquids such as ethane, propane and butane, which often occur along with natural gas, are offsetting the overall extraction cost for natural gas and holding down gas prices. However there is uncertainty as to how much natural gas liquids will provide a cost offset in the future.

GHG legislation that creates carbon pricing has the potential to make natural gas, with its lower emission intensity, an increasingly cost-effective choice relative to coal. Because of this, modest carbon pricing levels are likely to stimulate natural gas demand. However, much higher carbon pricing levels that may occur in the longer term would discourage natural gas in favour of even lower- and non-emitting technologies.

3.4.3 Oil Pricing

Oil use has diminished to a very small role in the electricity sector. The shale gas revolution has caused gas prices to fall dramatically while oil prices have remained near historic highs, making oil uneconomic for power generation for the foreseeable future. Oil is generally limited to a role as a start-up fuel, a backup fuel during natural gas interruptions and a fuel in areas where natural gas is not available. Oil prices have tended to exhibit high volatility over recent decades. While oil prices are unlikely to have a direct impact on generation decisions there may be indirect implications associated with overall economic growth and potential influences on natural gas pricing. Moderately priced oil has been traditionally linked to economic growth and therefore may have an indirect influence on North American electricity demand.

Higher oil prices since the early 2000s have led to high rates of return for conventional oil production and have expanded production from tight oil, shale oil and nonconventional sources such as the oil sands. While global consumption has since increased dramatically (driven largely by the economic development of emerging economies), U.S. consumption has declined in response to several factors including increased vehicle fuel efficiency, consumer response to price spikes and the general economic downturn.

Oil price forecasts are inherently uncertain. The price of oil depends on a complex set of factors including: technological advances in shale oil, tight oil, oil sands and other unconventional sources; overall global production and consumption; geopolitical threats to supply; and shipping, pipeline transportation and refining constraints.

3.4.4 Electricity Pricing

Regional electricity prices are based on both the variable cost of generation as represented by the market price for energy and the capital cost of investing in new generation, represented by the value of capacity.

From the perspective of meeting load requirements on a daily basis, it is the variable generation production costs that typically set a floor on the market price. In the near-term, the market uses the generation capacity that is already constructed and available. As a result, capacity costs are considered a sunk cost and do not influence the dispatch of generation or the short-term market price. The value of capacity is recovered by other rate mechanisms.

In a market such as MISO, generation resources are "stacked" relative to their variable cost of operation, with all dispatched units receiving the market clearing price, which is the value of the marginal (last accepted) offer required to meet the load. The price formulation process is explained in more detail in ***Appendix 5.2 - MISO Market Products, Operation and Locational Marginal Pricing***. The largest component in a generator's variable cost is fuel price; therefore fuel costs have a direct and notable effect on electricity prices. For MISO specifically, coal is the marginal or price setting fuel the majority of the time, with natural gas playing a lesser but growing role as marginal generation depending on the season.[25] Coal prices, therefore, are the driver for prices in MISO during the lower load off-peak periods, with natural gas and coal both influencing pricing during the higher load, on-peak periods. Lower gas prices, development of more gas capacity, and coal retirements are all expected to make gas the marginal fuel an increasing portion of the time.

Transmission can also influence electricity market prices. Transmission constraints (as well as generator outages) generally have short-term effects on regional pricing. Transmission constraints require the market operator to dispatch an alternate, more expensive, generator to ensure specific transmission lines will not be overloaded. The expansion of transmission throughout a region, such as is being called for in the MISO region to facilitate the delivery of wind to high-load areas, tends to have a price leveling effect across a region as it increases the amount of load that can be served by lower cost resources once the specific transmission path is no longer a constraint. This expansion of transmission infrastructure would tend to decrease electricity prices in higher-priced areas and increase them in lower-priced areas such as the Minnesota Hub that Manitoba Hydro connects with. Any chronic or structural regional congestion issues present in MISO are proactively addressed through a centralized transmission planning framework for the region. MISO's Transmission Expansion Planning process assesses, on an annual basis, whether regional congestion can be cost-effectively mitigated through new transmission infrastructure. If the cost of the new transmission infrastructure is offset by more efficient market operations (i.e. reduced transmission constraint costs) it would result in a recommendation for transmission investment.

Consistent with fuel price history, the MISO energy market has seen a marked regression from prices experienced in the 2006-2008 timeframe. However, electricity prices have stabilized over the past few years and are projected to experience moderate real growth. The extent of real price growth is contingent on a few key factors including real escalation in natural gas and coal

[25]https://www.midwestiso.org/MarketsOperations/MarketInformation/Pages/SeasonalMarketAnalysisReports.aspx

prices, expected coal generation retirements as a result of EPA regulations, and future carbon pricing and/or GHG emission regulations. Even absent meaningful new U.S. climate policies, power prices are likely to increase somewhat with rising fuel prices and coal retirements. A carbon price or other meaningful GHG regulation could increase prices significantly beyond that. Manitoba Hydro believes that some form of significant climate action in the U.S. is likely within the next 10 years. This could be realized through expansion of the existing regional carbon pricing or through national climate legislation and/or further regulation. A carbon price would inflate variable costs for all fossil fuels (particularly coal, which has the highest carbon content) and would result in substantial increases in electricity prices. If the U.S. continues to rely on EPA regulations to regulate GHG emissions, the likely outcome would be additional retirements of coal-fired generation, putting additional upward pressure on prices.

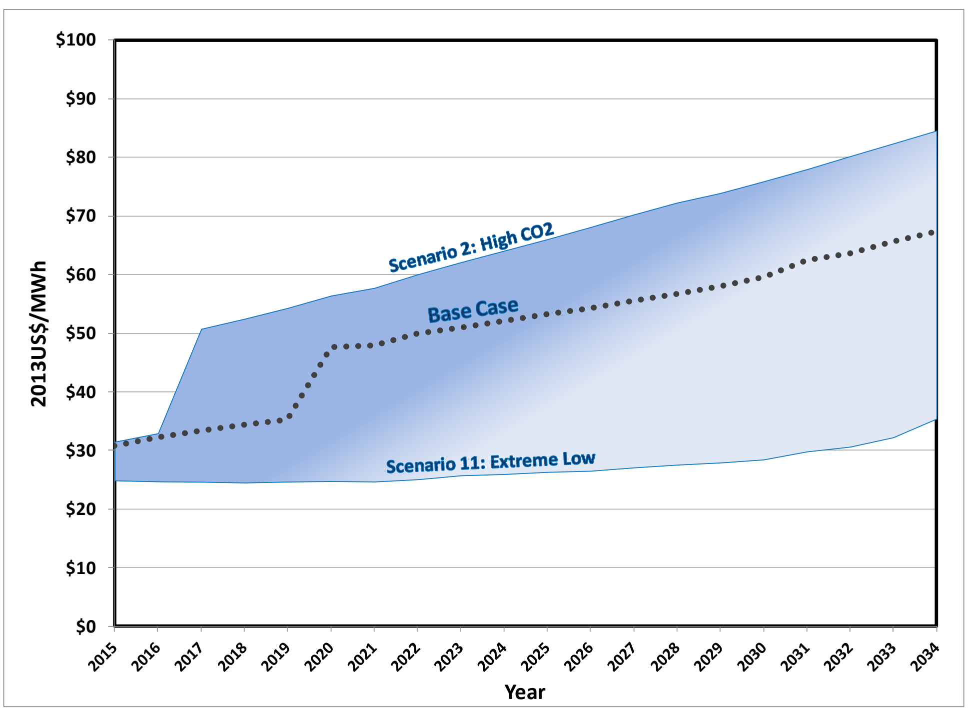
The second concept related to electricity prices relates to the cost of securing new generation capacity. Investment decisions for new generation consider a number of factors in addition to fuel prices. In addition to consideration of the type of resource needed (baseload, intermediate or peaking), factors influencing resource decisions include, but are not limited to, capital cost, electricity market prices, system reliability, fuel diversity, transmission requirements, corporate vision, and current and future environmental and energy policies. When making an investment decision, capacity costs as well as variable production costs for the life of the investment are considered along with other factors such as the location, fuel type, size and timing of any new capacity resource.

As discussed earlier, electricity prices have incorporated into them the effects of supply and demand, economic conditions, commodity prices and the impact of existing or potential energy and environmental policy. Based on these factors, electricity price forecasts are expected to increase in real terms over the long-term.

As part of its resource planning process, Manitoba Hydro seeks the opinion of a number of independent price forecast consultants whose perspectives form Manitoba Hydro's consensus electricity price forecast. The specific details of the consensus electricity price forecasts used by

Manitoba Hydro are confidential since public release could harm Manitoba Hydro in negotiation of contracts for export sales. However, in order to provide a general indication of the expected trend of future electricity prices in MISO, a 20-year electricity price forecast produced in 2013 by The Brattle Group is presented in Figure 3.13. The Brattle Group is one of the independent price forecast consultants whose perspectives are included in Manitoba Hydro's consensus electricity export price forecast. In developing their MISO price forecast, Brattle produces 11 distinct scenarios. Figure 3.13 shows their "Base Case" and the two scenarios which provide the upper and lower bound of prolonged pricing. A report on The Brattle Group's MISO price forecast is provided in ***Appendix 3.1 – Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO - The Brattle Group***.

Figure 3.13 **THE BRATTLE GROUP - MISO ELECTRICITY PRICE FORECAST**
ON-PEAK ENERGY AT MINN HUB



The Base Case forecast for the Minnesota Hub in MISO provided by The Brattle Group projects that on-peak energy prices will increase (in real terms) an average of 4% per year over the forecast horizon. A significant part of this growth is related to introduction of a moderate carbon price in 2019-2020. The Brattle Group's "High CO_2" scenario assumes introduction of a more substantial carbon price in the 2016 time frame, while the “Extreme Low” scenario assumes no carbon price accompanied by depressed fuel prices over the forecast horizon. As evidence of the vast uncertainty surrounding the key factors driving energy prices, there is a very large divergence (~$50/MWh) between the highest and lowest price scenario by the end of forecast horizon.

As noted, The Brattle Group’s price forecast is only one of a number of independent perspectives used to produce Manitoba Hydro’s consensus export price forecast. Therefore the prices in The Brattle Group’s forecast provided in Figure 3.13 are only indicative of a single perspective and do not necessarily reflect absolute pricing levels outlined in the consensus export price forecast.

3.5 Aging Generation Fleet

Several energy analysts have issued special reports over the past year or two estimating the amount of U.S. coal fleet generation that is expected to retire due to the confluence of environmental regulations accompanied by lower natural gas prices. There is a wide range in the estimates with anywhere from 30-100 GW of coal generation (of total U.S. coal capacity of around 340 GW) projected to retire within the next decade: the majority of estimates cluster around 50-70 GW. In its 2013 Annual Energy Outlook, the EIA projects 48 GW of coal-fired capacity will retire by 2020, representing 15% of the total U.S. coal fleet. MISO estimates 6-12 GW of coal capacity will retire by the end of the current decade. The units expected to retire are typically the older, smaller coal units that currently have a low annual capacity factor. These coal units are the most expensive and least efficient in the fleet; consequently, the reduction in coal capacity (about 15% across the U.S.) will impact total generation share by a much lower magnitude. For example, in MISO, the average size of a coal unit that is expected to continue operation is 350 MW, while the average size of a coal unit at risk of retirement is 80 MW.

Coal retirements place upward pressure on electricity prices. Removing coal capacity results in a more prominent role for natural gas in the generation supply mix and although most of the baseload coal capacity will remain, natural gas will have an expanded role in setting the marginal price in all regions. Removing coal will also advance the need for new generation capacity. Minimum capacity reserve margins must be maintained; therefore, retired coal capacity will have to be replaced and the capital costs will be borne by stakeholders. Higher utilization of natural gas results in additional infrastructure to move gas to the generation facilities, resulting in increased gas-electric coordination challenges and costs. Capital investment, in addition to increased volatility during peak periods, will add additional burden to the electricity sector. The environmental controls needed to comply with new EPA regulations (specifically mercury) will require additional processes and higher variable generation costs, resulting in higher operational costs for coal generation.

The nuclear fleet in North America is also aging. Existing plants are generally expected to retire after about 60 years of service (40 years under initial licence plus 20 years of life extension). However, the uncertainty over the long-term future of the U.S. nuclear fleet was increased by the March 2011 earthquake and tsunami damage to the Fukushima Dai-ichi nuclear plant in Japan. The incident highlighted the possible vulnerability of older reactor designs to extreme events. It has also decreased public and regulator confidence in nuclear plants and could increase costs as a result of additional safety requirements. As a result, there may be more pressure to close existing nuclear plants. Also the economics of major nuclear generation refurbishment are coming into question. The Kewaunee Power Station in Carlton, Wisconsin ceased operation in May 2013 after less than 40 years of service: the economics of this nuclear plant relative to electricity market prices were cited as the reason for the shutdown. Crystal River 3 (Florida) and San Onofre 2 and 3 (California) also shut down permanently in 2013, and additional nuclear plants may be vulnerable in an environment of low gas and electricity prices. The inability of the federal government to come up with a long-term nuclear waste storage solution also exacerbates the costs and acceptability of existing as well as new nuclear facilities. 19% of U.S. energy is supplied by nuclear generation, representing 790,000 GWh in 2011[26].

3.6 Summary

The need for new generation in the U.S. and Canada will be driven by modest load growth and the replacement of a portion of the aging generation fleet. Electricity demand in both Canada and the U.S. will continue to increase over the planning horizon.

Energy and environmental considerations and policies are another major factor influencing resource choices and market price for electricity. Global interest and attention to environmental issues and the effects of climate change could have a profound impact on the energy industry. Although the implementation of more aggressive economy-wide GHG policies has been delayed from earlier expectations and the timing remains unclear, ultimately it is expected that concern over the impacts of climate change will drive further legislation and regulation. Future GHG regulations are the largest potential driver for market price increases and for long-term changes in the composition of the energy mix. Ultimately, Manitoba Hydro expects that GHG emissions will be significantly constrained, either through federal or state/provincial legislation and/or regulation. Carbon pricing policies are being implemented in several states and provinces. Such carbon pricing systems add to the cost of fossil-fueled generation, increase market prices for electricity and increase the level of incentive and the demand for low and non-emitting resources. Although there is uncertainty in the future of GHG policies, by choosing low- and non-emitting resources, generators are sheltered from the risk of financial impacts associated with potential GHG policy and regulation.

Largely because of its GHG and other emissions, coal has been facing increasing challenges. For years state-level regulatory and licensing processes have made it increasingly difficult to site

[26]http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vud&geo=g&sec=g&freq=A&start=2001&end=2012&ctype=linechart&ltype=pin&pin=&rse=0&maptype=0

new coal facilities. Now a set of new regulations in the U.S. are being developed that could preclude the development of new conventional coal generation (i.e. without carbon capture and storage technology), accelerate retirements and in the long-term substantially reduce the reliance on coal generation. The anticipated cost of meeting these future U.S. regulations is driving coal retirement considerations in many regions; although retirements currently appear to be restricted to the oldest, smallest and often least-used units. A new Canadian regulation is precluding new conventional coal generation and is effectively phasing out existing conventional coal generation as each unit reaches its fiftieth anniversary.

RPS exists in many states to encourage the development of renewable electricity generation. These policies require a certain proportion of energy served to be delivered from eligible renewable sources. Proposals for similar national systems have been considered by the U.S. Congress. To the extent that these types of programs include Canadian hydropower as an eligible resource, they would provide an additional incentive to buy electricity from Manitoba. In addition, RPS and other policies that are driving an increase in generation from intermittent renewable resources (like wind and solar) can add demand and value to flexible and dispatchable hydropower that can complement these resources. (See ***Chapter 6 – The Window of Opportunity*** for a more detailed treatment of this effect in the MISO region).

Recent developments in oil and gas extraction have significantly increased the availability of these resources. The growth of shale gas production (5% of U.S. gas production in 2006, up to 34% in 2011) has resulted in an abundant new U.S. supply source and has changed the long-term outlook for domestic natural gas prices. While an overabundance in the supply of natural gas was experienced in 2012, prices have recovered to land above $4/mmBTU in 2013. Forecasts for natural gas prices can diverge widely; however, the U.S. Department of Energy expects that prices will fluctuate around the $4/mmBTU price level until 2020 followed thereafter by moderate price growth, and future prices are currently somewhat above this.[27]

[27] All above is in 2011$

Investment decisions in new generation, consider multiple factors, including capital investment for new plants, regulatory risks and fuel supply and cost, specifically as it relates to long-term fuel availability and stability. In the U.S., constraints on new coal generation and the outlook for fuel prices support the expectation that natural gas will be the primary choice for new generation. However, natural gas is seen by many as a transitional fuel choice offering emission reductions relative to coal but still carrying a considerable GHG emission liability. GHG legislation that creates carbon pricing has the potential to make natural gas an increasingly cost-effective choice relative to coal due to its lower emission intensity. Because of this, modest carbon pricing levels will stimulate natural gas demand. However, in the longer term, much higher carbon pricing levels would discourage natural gas in favour of even lower and non-emitting technologies, including hydro-electricity generated by Manitoba Hydro.

Regional electricity prices are based on both the variable cost of generation represented by the market price for energy, and the capital cost of investing in new generation, represented by the value of capacity. As discussed in the earlier sections of this chapter, electricity prices have incorporated into them the effects of supply and demand, economic conditions, commodity prices and the impact of existing or potential energy and environmental policy. Based on these factors, electricity price forecasts are expected to increase in real terms over the long term.

Electricity demand in both Canada and the U.S. will continue to increase over the long-term and there will also be a need to replace a portion of the aging generation fleet. These are the factors that are expected to drive new generation requirements. While many utilities will choose to develop natural gas generation, they are likely to continue to seek out emission-free alternatives in order to diversify their portfolio of resources, mitigate expected natural gas price uncertainty and volatility, protect against future carbon price liabilities, and improve their overall environmental performance.

---

http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=3-AEO2013&table=13AEO2013&region=0-0&cases=ref2013-d102312a