Pathways to a Reduced Carbon Energy System For the Upper Midwest

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Executive Summary

Strategies to reduce emissions of carbon dioxide, as well as other greenhouse gases, are important elements of a climate change mitigation strategy. Although many studies have sought to outline a reduced-carbon energy system for individual states, few if any have included economics, and few if any have included an entire region. The goal of this study is to develop scenarios, to reduce carbon dioxide emissions from the electric power generation sector in the upper Midwest (Wisconsin, Illinois, Minnesota, Iowa, North Dakota, South Dakota, Montana, Wyoming, and Manitoba).

The electric power generation sector currently accounts for nearly half of total carbon dioxide emissions in this region. For this study, an analysis was conducted to determine how this sector might meet projected electric power demand between now and 2055, while reducing carbon dioxide emissions to 20 percent of 1990 levels. Renewable energy technologies, nuclear power, advanced combustion, and coal gasification with carbon sequestration were included in the analysis, as was the potential for end-use efficiency and conservation. The potential for each power generation technology was measured against resource opportunities and constraints within the region. Costs were also evaluated. A summary of the technology analysis is shown in Table 1.

Table 1:
Summary of Power Generation Technologies

Technology	Potential Capacity within the Region	Installed Cost[1] ($/MW)	CO2 Emissions[2] (tonnes/MWh)	Average Price of Electricity[3] (¢/kWh)
Wind	607.920 MWa[4]	$1,134,000	0	3.39
Conventional Hydro	16,000 MW	$1,451,000	0	2.99
Municipal Solid Waste/ Landfill Gas	Uncertain	$1,500,000	0	7.69
Biomass	77,000 MW	$1,757,000	0	5.56
Nuclear	Unconstrained	$1,957,000	0	3.19
Photovoltaic	Currently economically constrained	$4,467,000	0	18.6
Coal (IGCC w/CCS)	Uncertain	$2,006,000	0.09 – 0.1	4.62 – 5.25
NGCC	Uncertain	$567,000	0.36	10.6
Coal (IGCC)	Unconstrained	$1,402,000	0,77 – 0.81	2.76 – 3.29
Distillate Fuel Oil (steam)	Limited	$395,000	0.82	13.6
Coal (steam)	Unconstrained	$1,213,000	0.82 – 0,87	2.24 – 2.81

Notes:
[1] Installed costs were derived from EIA information and other sources where needed.
[2] For coal technologies, the range of values represents differences between bituminous, sub-

bituminous and lignite coals.

[3] Based on average plant gate costs in the eight states and Manitoba. Calculations made using S. J. Taff. (Department of Applied Economics, University of Minnesota, 2006).

[4] MWa: Megawatt average. Represents an average capacity that accounts for the variability of wind in each wind class. Reliability is assumed at 33.3%.

[5] Strictly speaking, natural gas plants are available much more than this. This is the percent of the time that natural gas plants are actually used currently, owing to their function as peaking plants

The analysis revealed that there are several pathways that could lead the region to the carbon dioxide emission goals. Five scenarios were developed, each presenting a different mix of end-use efficiency and power generation technologies that would meet electric power demands, and carbon dioxide emission constraints. Despite variations in technologies, costs, as represented by the average cost of electricity, differed by 10 to 20 percent, revealing that policy decisions may play a more significant role than economics in determining which pathway the region might follow. The various scenarios are summarized in Table 2.

Table 2:
Year 2055 Electric Power Generation Scenarios for the Region

Scenario	Power Generation Mix		Average Cost of Electricity ($/MWh)
Lowest Cost	Demand management: 0% Wind: 0% Biomass: 0% Hydroelectric: 4%	Coal (steam): 84% Coal IGCC w/CCS: 0% Nuclear: 10%	$26
Lowest Cost Reduced CO2	Demand management: 0% Wind: 7% Biomass: 0% Hydroelectric: 8%	Coal (steam): 3% Coal IGCC w/CCS: 0% Nuclear: 81%	$32
High Wind, Nuclear, and Hydro	Demand management: 0% Wind: 40% Biomass: 0% Hydroelectric: 7%	Coal (steam): 0% Coal IGCC w/CCS: 0% Nuclear: 52%	$33
High Coal	Demand management: 0% Wind: 30% Biomass: 3% Hydroelectric: 3%	Coal (steam): 0% Coal IGCC w/CCS: 44% Nuclear: 18%	$35
No Coal or Nuclear	Demand management: 57% Wind: 21% Biomass: 16% Hydroelectric: 5%	Coal (steam): 0% Coal IGCC w/CCS: 0% Nuclear: 0%	$38

Notes:
In all scenarios, peaking, which varies between 1 and 2 % of total generation, makes up the remainder of the mix. In the Lowest Cost Scenario, CO2 emissions continue to rise and the CO2 target is not met.

[1] S. J. Taff. (Department of Applied Economics, University of Minnesota, 2006).

Cost numbers are generated by the CO2 model produced by Steven J. Taff .[1] In the No Coal or Nuclear scenario, the price range reflects uncertainty about the cost of reducing demand.

Achieving the magnitude of carbon dioxide emission reductions tested in this study requires an immediate transition to a reduced-carbon pathway. It is critical that reduced-carbon technologies are adopted as opportunities to replace retiring capacity in the existing system present themselves. Further investments in traditional, carbon-intensive technologies have long-term consequences, ensuring carbon dioxide emissions over the lifetime of each new facility, and delaying progress toward emission reductions.

I. Introduction

As policy issues related to climate change appear more frequently on the agenda of national, state, and local governments, there is a need for objective evaluation of strategies to reduce greenhouse gas emissions. The focus of this study was the development of scenarios, combining political, economic and technological drivers, for reducing carbon emissions in the electric power generation sector in the upper Midwest region (Illinois, Wisconsin, Iowa, Minnesota, South Dakota, North Dakota, Wyoming, Montana and Manitoba). For the purpose of this analysis, the goal was to reduce carbon dioxide emissions from electric power generation in the region to 20 percent of 1990 levels while meeting projected electric power demands by 2055.

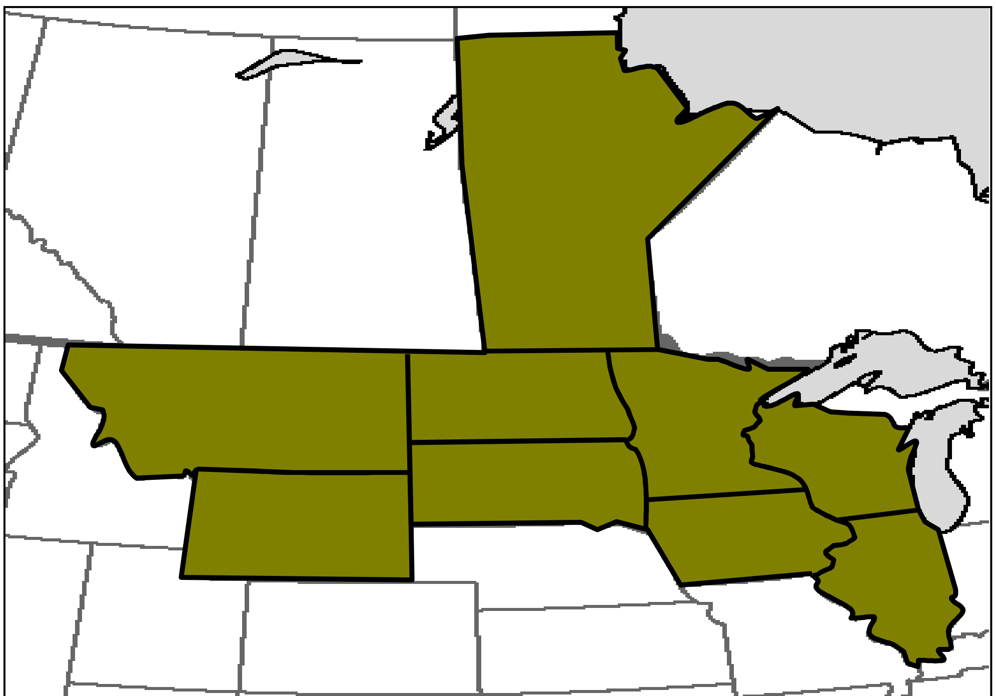

Figure 1: The study region.

Although many studies have sought to plan the energy future of a state to create a reduced-carbon or carbon-neutral energy system, few have included economics, and few have included an entire region. While other researchers have taken a similar approach in considering the contributions of different energy and efficiency "wedges" in contributing to an 80 percent reduction in global greenhouse gas emissions, this study took the analysis a step further and attempted to evaluate the costs of these scenarios. Rather than simply assuming how much of a given energy technology can be used, this analysis placed constraints on the use and implementation of specific technologies based on the relative abundance or scarcity of physical resources in the upper Midwest region, and gave consideration to the existing electric power generation infrastructure. Finally, while other scenario studies have been conducted by advocacy groups with particular technologies in mind, this study evaluated energy resources by carbon-content alone and compared these technologies by cost. There was no attempt to present technologies or solutions according to other political, social, or non-carbon-related environmental preferences. Other preferences and values clearly have a role to play in the formulation of public policy relative to out future energy choices, but they fell outside the scope and methodology of this study.

The study was conducted in two parts. A research team at the Hubert H. Humphrey Institute of Public Affairs at the University of Minnesota studied the regional energy system to understand the context in which changes could be contemplated. This included analysis of the region's resources, the costs associated with existing and developing technologies, and the potential for emissions reductions in the region. A parallel effort conducted by the Department of Applied Economics at the University of Minnesota resulted in the development of a system dynamics model for use in conjunction with this analysis. The model integrated the technology and cost assumption developed in this analysis that would allow users to evaluate the effects of technological, economic, and policy changes on the electric power generation sector over the next 50 years.

The study was developed in collaboration with regional legislators, the Powering the Plains (PTP) initiative of the Great Plains Institute (GPI), the University of Minnesota, and the Legislators' Forum. Funding and in-kind support were provided by the Initiative for Renewable Energy and the Environment (IREE), the Great Plains Institute, and the Garfield Foundation.

II. Background

The study region included jurisdictions that share a traditional regional affiliation through the Mid-continent Area Power Pool, as well as many important shared energy and climate-related resources, opportunities and challenges.

The study was limited to emissions of carbon dioxide from the combustion of fossil fuels in the electric power generation sector, which account for the majority of greenhouse gas emissions, both in this region and worldwide. Similarly, carbon dioxide is thought to have the greatest impact on climate (in terms of total greenhouse gas loading, rather than impact per ton) of any of the greenhouse gases. Future iterations of this study could include the other major greenhouse gases. This study, however, provides a complete analysis of the activities that play the largest role in climate change, which are those associated with carbon dioxide emissions.

The goal of reducing carbon dioxide emissions to 20 percent of 1990 levels was chosen because this is the level of annual global emissions that will allow for stabilization of the atmospheric carbon dioxide concentration at 500 parts per million, according to the Intergovernmental Panel on Climate Change (IPCC).[2] Our goal is actually more ambitious than the IPCC's goal; they target an 80% reduction by 2100 rather than 2055. The global scenario would likely require different emissions reduction targets for different countries and jurisdictions. This could mean that the study region would have to reduce its emissions to more or less than 20 percent of 1990 levels in contributing to global goals. Mitigating climate change would also require similar reductions for other greenhouse gases that aren't considered in this study.

[2] "Climate Change 2001: Summary for Policymakers" (Intergovernmental Panel on Climate Change, 2001).

It can be argued that the study region has the greatest resources for carbon-neutral power in the country, including currently underutilized wind and biomass resources, abundant coal resources accompanied by opportunities for geologic sequestration, the potential for development of additional hydroelectric power, and terrestrial sequestration resources in agricultural land and forested land. The region could potentially achieve a greater than 80 percent reduction in carbon dioxide emissions in the electric power generation sector, and contribute to reductions in other regions, either through emissions credit trading or exports of energy.

III. Approach

A number of national and international groups have been involved in recent years in developing scenarios for carbon dioxide (or carbon) emission reductions. In 2001 the IPCC released its Third Assessment Report[3], which provided a synthesis of current knowledge regarding carbon emissions and mitigation. The National Renewable Energy Lab (NREL) is sponsoring several projects to evaluate the costs and benefits of greenhouse gas reduction, including the International Co-control Benefits Analysis project and the Climate Technology Initiative.[4] The Carbon Mitigation Initiative (CMI) at Princeton University, a joint project with British Petroleum and the Ford Motor Company, is conducting multiple research projects related to climate change and greenhouse gas emissions reduction. Researchers with CMI recently published a paper that evaluates 15 options for reducing global carbon emissions using available technologies.[5]

This project applied many of the same analytical approaches used in these studies to the specific circumstances of the upper Midwest region, and considered the likely technological changes and implementation opportunities that would allow an 80 percent reduction in carbon dioxide emissions over the study's time period. The study incorporated assumptions about the availability of different resources, and the likely trends in the costs of both existing and near-term technologies, based on a summary of various research sources. Technological and resource development potential was assessed within a framework of varying political and economic forces.

An inventory of the region revealed that the electric power generation sector contributes the largest share of carbon dioxide emissions in the region. Electric power generation from coal-based technologies accounted for over 42 percent of total carbon dioxide emissions in the region (excluding Manitoba) in 2000. As the largest contributor of carbon dioxide emissions, this sector was the focus of this study.

A transformation of this scale required a detailed analysis of the existing electric power supply for the region, an evaluation of resource availability, and an assessment of current and potential electric power generation technologies. Evaluation of all of these elements within a regional context will allow policy makers to select investments in technological development, and adopt policies to encourage deployment of new technologies that optimize specific regional assets. A

[3] "3rd Assessment Report" (Intergovernmental Panel on Climate Change, 2001).
[4] Need Reference
[5] Pacala and Sokolow, Science, August 13, 2004

long-term planning horizon will allow time for adoption and implementation of policies and technologies that would enable the targeted carbon dioxide emission reductions.

It was assumed that each sector would be treated in isolation, so that carbon dioxide emissions from the electric power generation sector should be reduced to 20 percent of 1990 levels. Specifically, the study includes evaluation of the following options for the region to achieve this goal:

- Further development of renewable power in the region, including wind, biomass and hydroelectric power.
- Replacement of traditional coal-fired power production technologies with reduced-carbon emission technologies and fuels.
- Implementation of carbon capture and sequestration for fossil fuel-driven power generation.

In order to calculate the carbon-reduction potential and costs for these options, the following information was assembled.

- The overall scale of the resource within the region (if such information was available)
- The costs associated with existing and near-term technologies
- The carbon impact of existing and near-term technologies
- The overall potential of the resources and technologies to contribute to carbon reduction in the region.

Scenarios were developed combining varied levels of renewable and traditional technologies to satisfy projected electricity demands in the region. Costs of electricity under these scenarios were computed.

IV. Regional Carbon Dioxide Emissions Inventory

In order to calculate a baseline for regional carbon dioxide emissions, a historical record of emissions was assembled. Data from the Department of Energy's Energy Information Administration (EIA)[6] were used to calculate an emissions record for the seven states from 1960 to 2001. (Data for the same time period were not available for Manitoba.) Carbon dioxide emissions were calculated using the EPA's State Emissions Inventory Tool[7] methodology, which calculates estimated carbon dioxide emissions based on volumetric fuel use. The baseline emissions data were used to depict historical emissions and trends, to project business-as-usual emissions and to establish 1990 emissions levels.

Figure 2 shows emissions for the seven states in the region for 1960 to 2001. The goal of reducing regional emissions to 20 percent of 1990 emissions translates into a target of 111 million metric tons in 2055. This is 16 percent of estimated 2001 emissions, and well below the estimated emissions in 1960. The carbon dioxide emissions inventory used in this study allocated

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[6] EIA-906/920 and EIA-860.
[7] EIA-906/920 and EIA-860, 2004 data.

emissions to the location where the fuel was burned, rather than where the electricity was used. This methodology corresponds to the way fuel use data is collected and categorized by the EIA. Allocating emissions to the electricity end use was beyond the scope of this study. Although this methodological decision may draw readers to the conclusion that the electric power sector is actually to blame for the high emissions from burning coal, it could just as easily be recognized that those emissions are the result of electricity demand from individual users. The study authors intended no value judgment in how this data was presented.

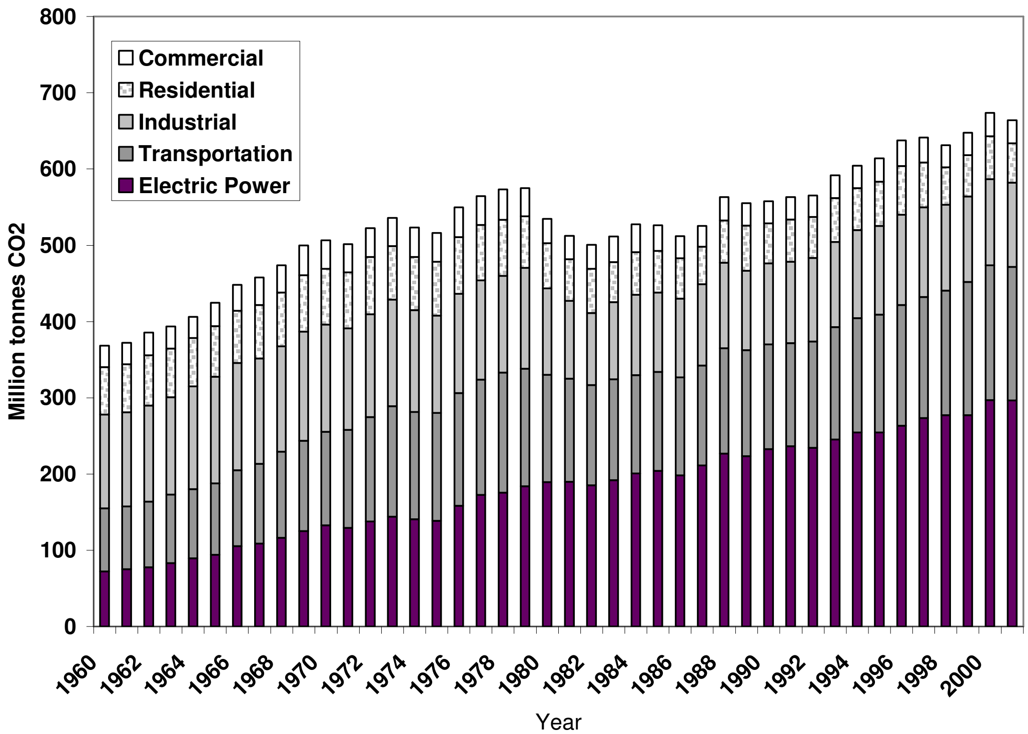

Figure 2: Total CO2 Emissions from the Region (excluding Manitoba), 1960-2001
Carbon dioxide emissions in 1990 were approximately 558 million metric tons. When data from Manitoba for 1990 are included, the total regional carbon dioxide emissions in 1990 are estimated at 604 million metric tons. Relative stability in residential, commercial, and industrial sectors is likely due to substitution of on-site power generation in these sectors with purchased electricity. This is reflected by the growth in emissions from the electric power sector.

Figure 3 shows carbon dioxide emissions broken down according to fuel type for 1960 to 2001.

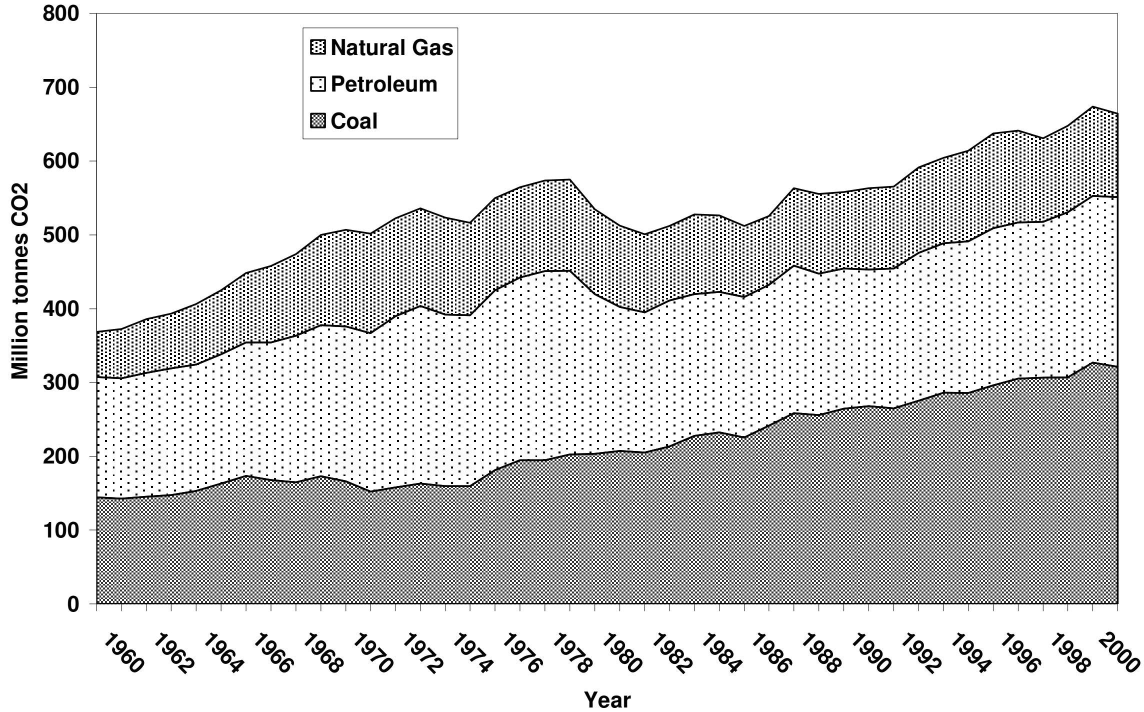

Figure 3: CO2 Emissions by Fuel Type, 1960-2001
This data correlates with the emissions-by-sector trends, as most coal use was in the high-growth electric power generation sector, and most petroleum use is in the high-growth transportation sector.
Source: EIA-906/920 and EIA-860.

Total carbon dioxide emissions were broken down by sector and by fuel for both 1960 and 2000 in Figure 4 to demonstrate the overall growth in electricity demand, and compare the growth in emissions among the sectors and fuel types. Two sources of emissions are prominent: carbon dioxide emissions from coal use in the electric power generation sector, and petroleum use in the transportation sector.

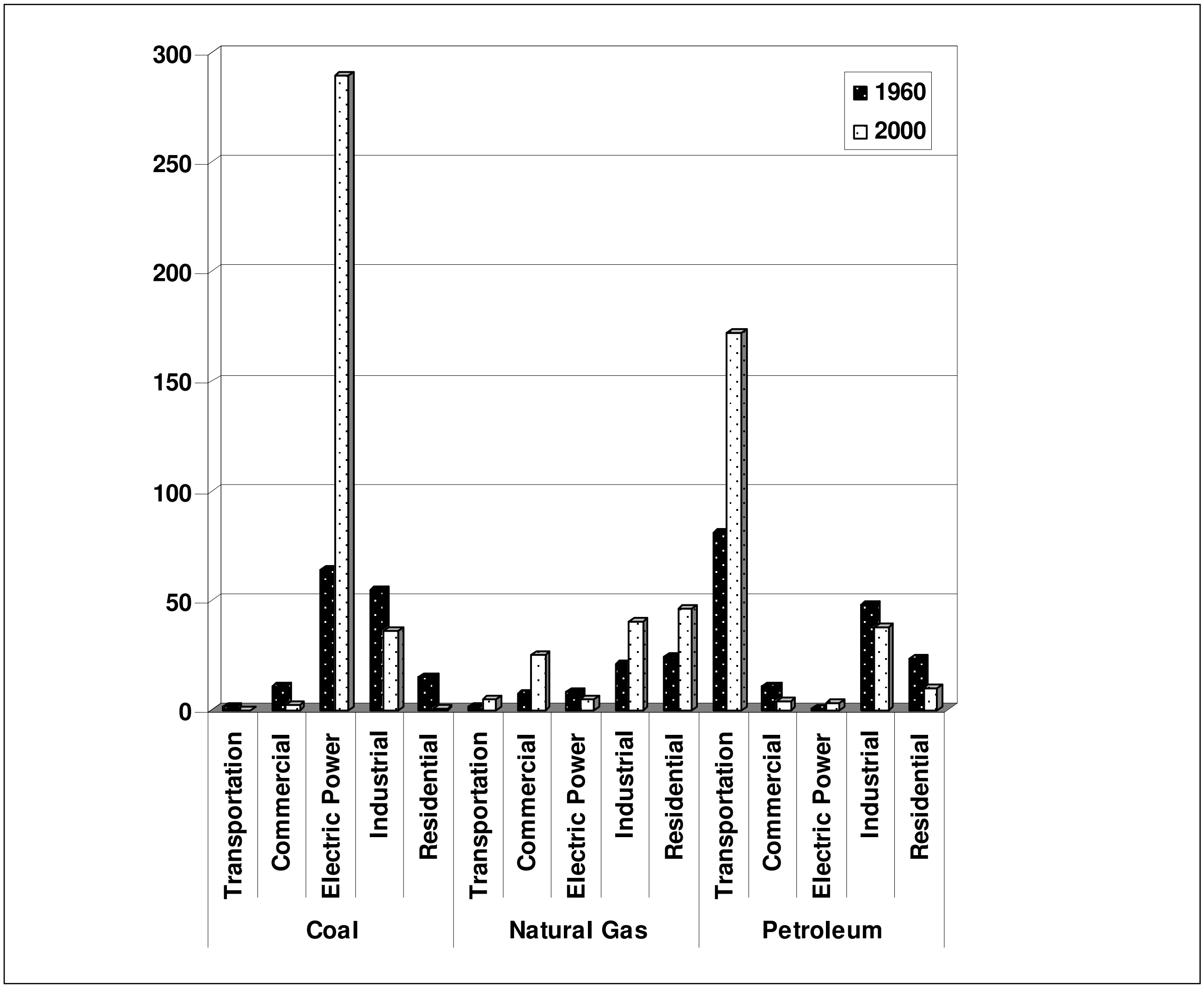

Figure 4: CO2 Emissions by Sector and Fuel Type, 2000
Source: Authors' analysis using data from EIA-906/920 and EIA-860.

Figure 5 shows total emissions by state from 1960 to 2001.

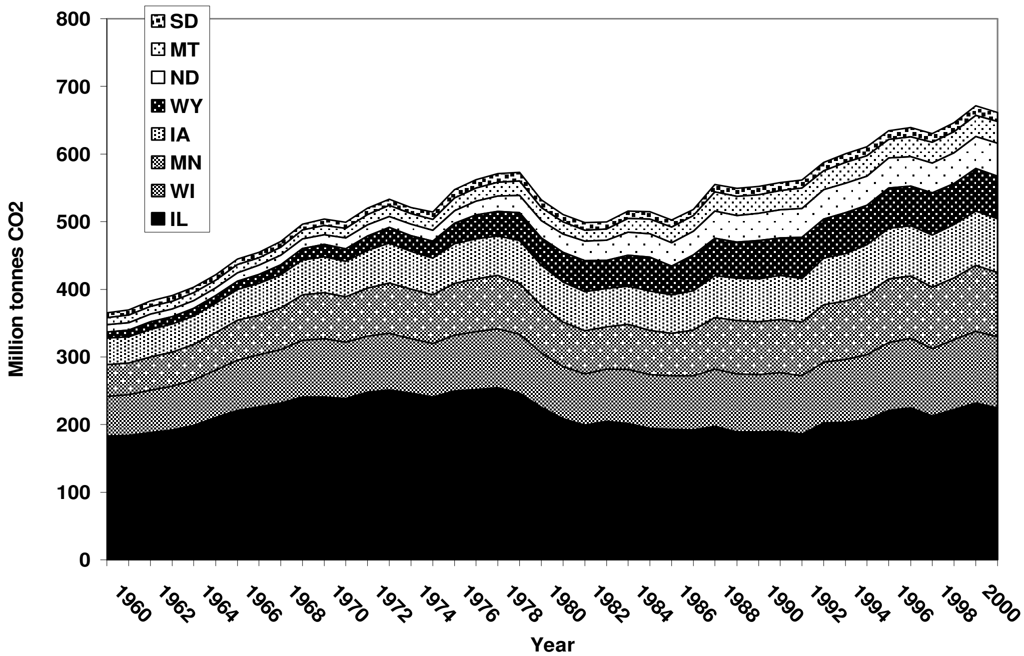

Figure 5: CO2 Emissions by State, 1960 – 2001
Proportions of emissions among the states have remained relatively constant over the past four decades. Emissions in all states declined in the early 1980's likely due to high fuel prices and contraction of the U.S. economy.
Source: Fuel use data from EIA-906/920 and EIA-860. Emissions were calculated using methodology developed for the EPA's State Emissions Inventory Tool.

Figure 6 compares total carbon dioxide emissions, emissions per capita, and emissions per gross state product for each of the states in the region and Manitoba. It is apparent that different jurisdictions rank very differently depending on the standard that is used. For example, comparing Illinois and Wyoming reveals that Illinois performs relatively poorly in terms of total emissions, but relatively well when emissions are linked to either gross state product or population. Wyoming performs the worst of all states/provinces when emissions are linked to either gross state product or population. Manitoba performs the best in all categories, primarily because its electric power generation system is dominated by large-scale hydroelectric power, which is considered carbon-neutral

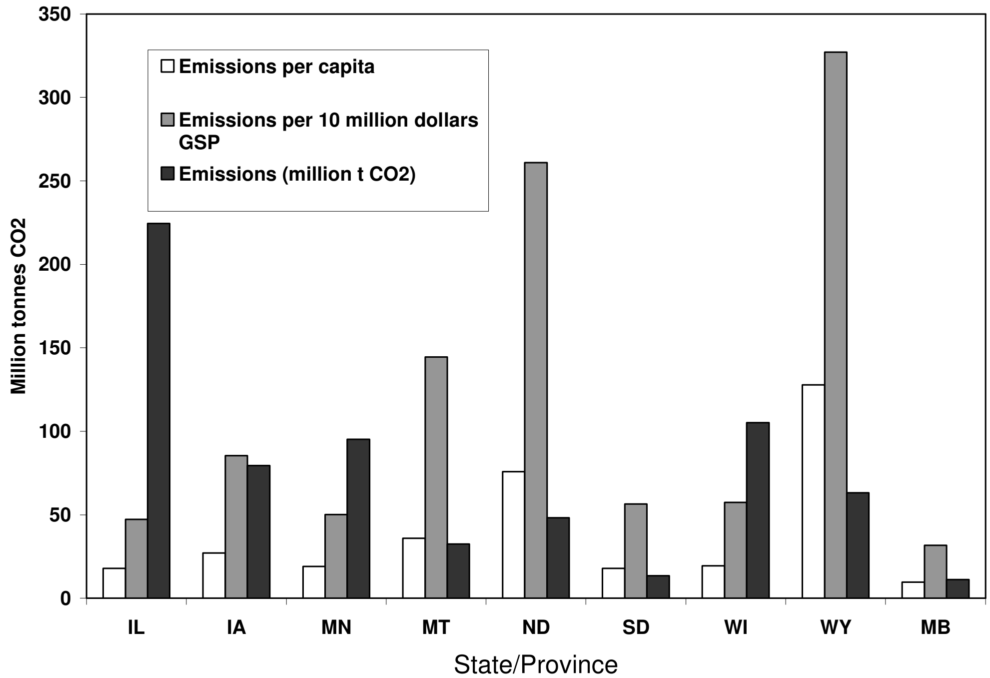

Figure 6: Total Emissions, Emissions per Capita, Emissions per Gross State Product.
Emissions based on 2001 data.
Source: Emissions calculated using data from EIA-906/920 and EIA-860 and the methodology developed for the EPA's State Emissions Inventory Tool.

Because carbon dioxide emissions were allocated to the location where the fuel was burned, rather than where the electricity was used, this state-by-state comparison does not account for imports and exports of electricity.

The record of regional emissions was used to create a business-as-usual emissions projection, which is shown in Figure 7.

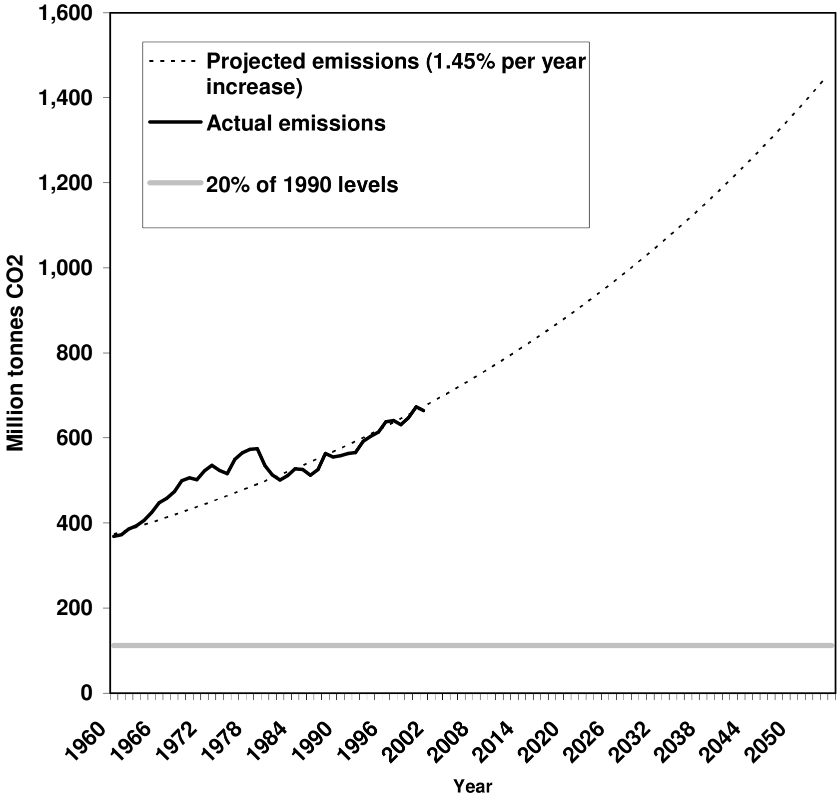

Figure 7: Business as Usual Emissions Projection
The projection assumes a constant annual rate of growth of 1.45 percent, which was derived from the 1960 to 2001 trend. The straight line at the bottom represents emissions at 20 percent of 1990 levels.

V. Electric Power Sector Profile

Fuel sources used to generate electric power in the region are profiled in Figure 8. Table 3 provides a more detailed look at net generation from different energy sources. In the table, fuel types are divided into carbon-based and carbon-neutral according to the EIA and EPA classification systems.

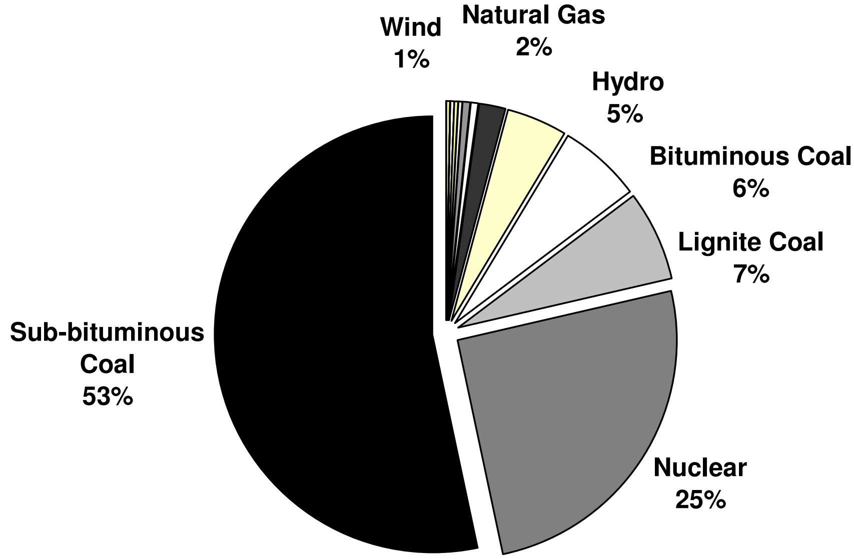

Figure 8: Regional Electric Power Profile
The values represent the percentage of total electric power generation by fuel in the region in 2004
Sources: Compiled from EIA-906/920 and EIA-860, Manitoba Hydro (www.hydro.mb.ca), U.S. Nuclear Regulatory Commission website (www.nrc.gov)

Table 3:
Net Generation by Fuel Type, 2004

Fuel Type	Total Number of Facilities in Region	Net Generation (GWh)
Carbon-Based Fuels		
Sub-bituminous Coal	73	226,559
Lignite Coal	8	29,271
Bituminous Coal, Anthracite Coal	38	25,450
Natural Gas	155	8,039
Petroleum Coke	13	1,406
Landfill gas	9	870
Municipal Solid Waste	7	754
Residual Fuel Oil	14	602

Distillate Fuel Oil	146	408
Other Gas	4	298
Coal-based Synfuel	3	269
Waste/Other Coal	1	183
Tire-derived Fuels	8	177
Other	2	53
Blast Furnace Gas	1	16
Waste/Other Oil	2	4
Jet Fuel	2	0.0
Subtotal	413	294,360
Carbon-Neutral Fuels		
Nuclear	18	107,332
Conventional Hydro	52	50,536
Wind	29	3,245
Wood/Wood Waste Solids	17	712
Black Liquor	6	593
Other Biomass Gas	5	121
Purchased Steam	1	46
Other Biomass Solids	2	12
Sludge Waste	4	7
Ag Crop Byproduct	2	6
Wood Waste Liquids, excl. BLQ	1	0.2
Subtotal	137	162,612
Total	550	456,972

Sources: EIA-906/920 and EIA-860, Manitoba Hydro (www.hydro.mb.ca), 2004

Figure 9 shows regional carbon dioxide emissions for the electric power sector delineated by fuel type for 1960 to 2001. Emissions from coal-fired power generation dominate both in terms of total emissions and growth in emissions.

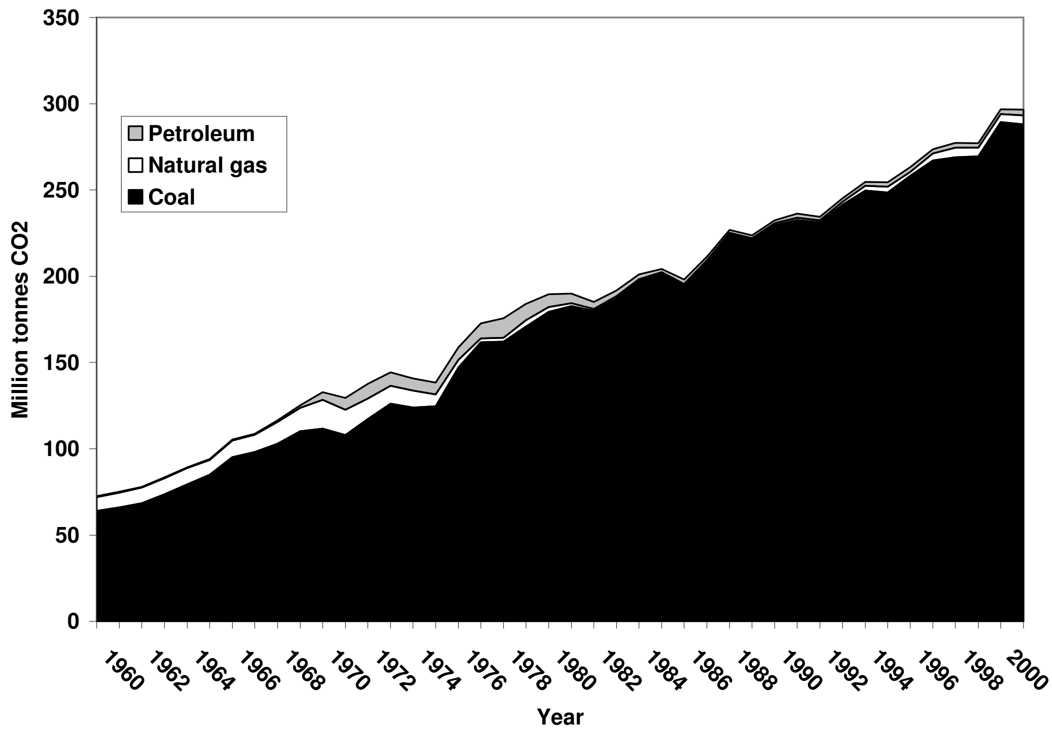

Figure 9: Electric Power Sector Emissions, 1960 – 2001
Source: Fuel use data from EIA-906/920 and EIA-860. Emissions were calculated using methodology developed for the EPA's State Emissions Inventory Tool.

Electricity demand by sector for the U.S. states in the region is shown in Figure 10. Because all sectors are assumed to consume electricity with the same carbon dioxide emissions characteristics, this is a fair representation of how electric power emissions are allocated to the commercial, residential, and industrial sectors. Although the transportation sector does consume electricity, it is too small in proportion to the other sector demands to appear in the figure.

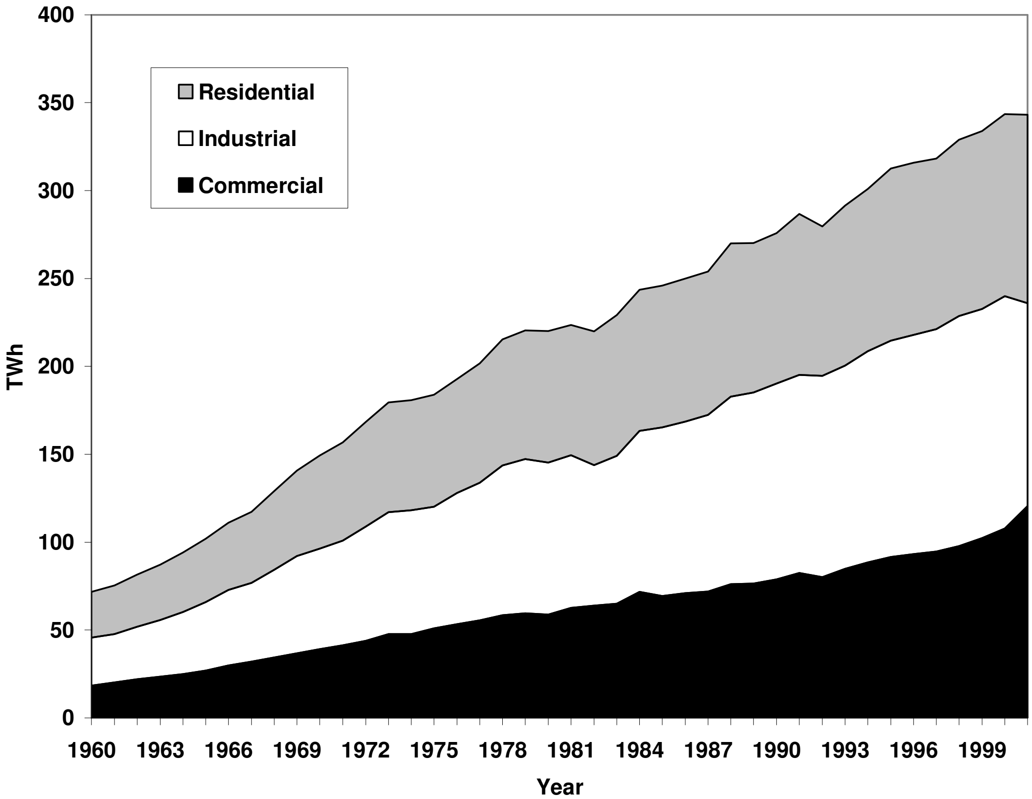

Figure 10: Electricity Demand by Sector, 1960 – 2001 (excluding Manitoba)

Electric power generation is a highly scale-dependant industry. Figure 11 demonstrates how a large portion of electricity generation and carbon dioxide emissions are concentrated in a few large power stations. Although the study found just over 600 total stations in the region, ten 10 percent of net generation in 2003 occurred in just 3 stations. Carbon dioxide emissions are similarly concentrated in a few large facilities.

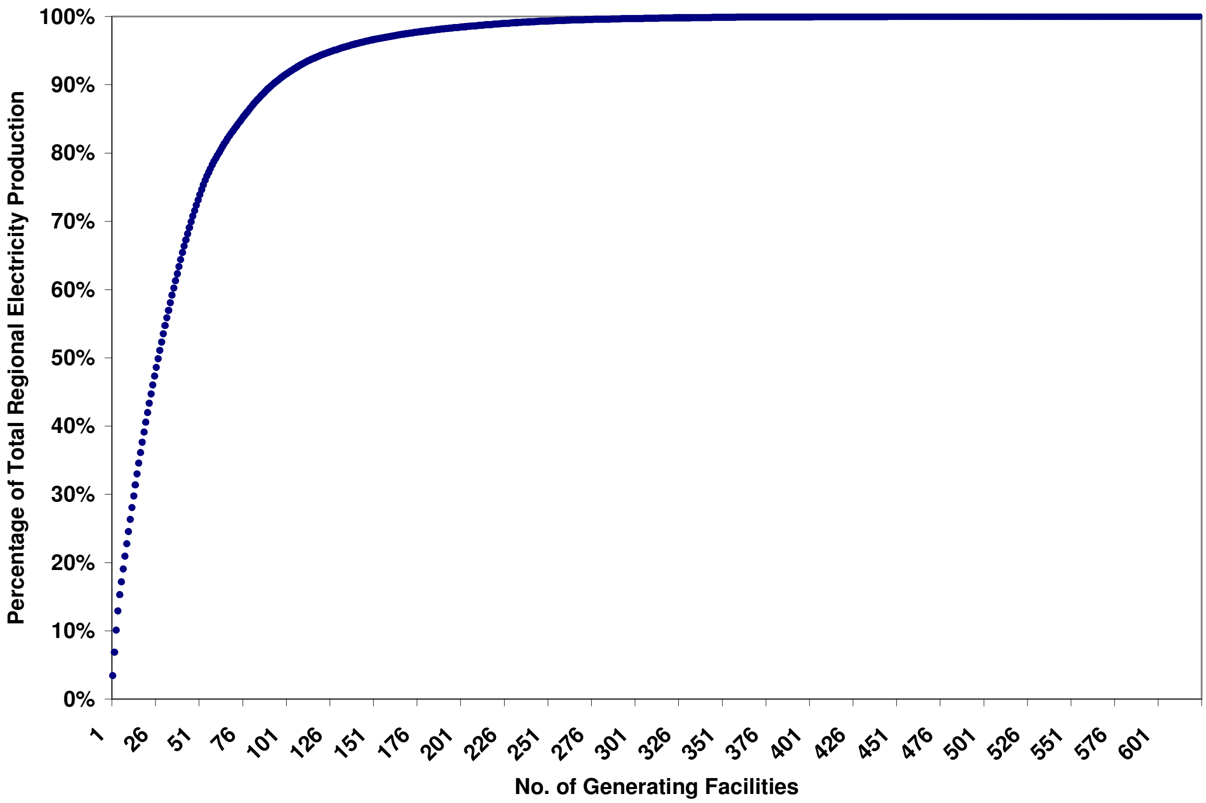

Figure 11: Concentration of Power Production.
Shows total percentage of net generation in the region in 2004. Three power stations generate over 10 percent of the region's electric power. Twenty-four percent net generation occurs in 10 stations, 50 percent in 20 stations, and 90 percent in 95 stations.
Sources: Compiled from EIA-906/920 and EIA-860, Manitoba Hydro (www.hydro.mb.ca), U.S. Nuclear Regulatory Commission website (www.nrc.gov)

Electric Power Demand Projections

To project emissions from a transformed electric power sector, electricity demand projections were computed. These were based on historical demand trends in the region, and national demand projections used by the Energy Information Administration, which projects annual increases in electricity demand of 1.9 percent.[8] Electricity demand in the region is expected to increase with population and continued economic development from 457 terrawatthours (TWh) in 2004 to 948 TWh in 2055. Historical demand and projections to 2055 are shown in Figure 12.

[8] Energy Information Administration, Annual Energy Outlook2005, <2005, http://www.eia.doe.gov/aoif/aio/demand.html>

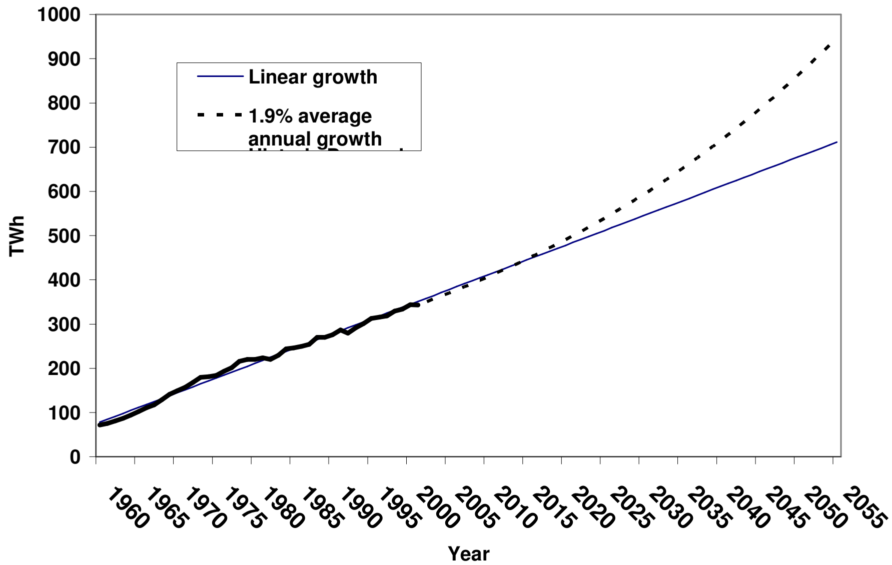

Figure 12: Demand Trends and Projections, 1960 - 2055
Annual demand for electricity in the region increased five fold from 1960 to 2000. Assuming an annual increase of 1.9 percent, demand is projected to reach over 950 TWh in 2055, nearly three times 2000 demand.
Source:

Electric power demand in the region is currently met by over 600 power generation facilities. As these facilities reach the end of their physical lives, their generation capacity will need to be replaced by new or re-powered facilities, and additional capacity will be needed to meet growing demand.

Figure 13 shows the projected gap between existing power generation capacity and demand between 2005 and 2055. For this analysis, data on the start-up year for each facility were assembled. An average lifetime of 50 years was assigned to each facility to estimate a retirement date. New capacity will need to be added to meet projected demands, and to offset the retirement of existing capacity. The chart shows the schedule for retirement for the existing power production capacity in the region, and shows the capacity deficit that will need to be met by new or re-powered facilities.

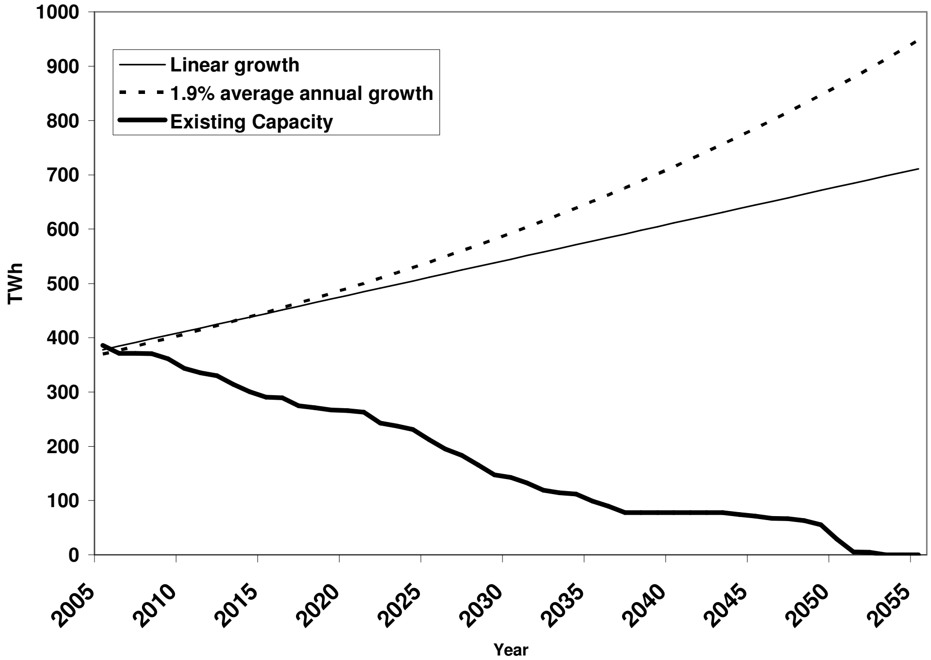

Figure 13: Power Generation Capacity Needs, 2005 - 2055
Generation in TWh applies an average capacity factor of 50% to the total nameplate capacity of all facilities in the region. The average capacity factor was based on reported operating data for each power generation unit in the region for 2004.[1]

Effect of Demand-Side Efficiencies and Conservation on Demand Projections

Demand-side efficiency and energy conservation have the potential to reduce the growth rate of electric power demands. Although methods and technologies to achieve demand reductions were not included in this study, research projects that demand reductions of up to 12 percent are achievable in the long term. For this study demand-side efficiency and conservation were treated as net reductions in electricity demand, and therefore have the potential to reduce carbon dioxide emissions associated with electricity generation. Supply-side efficiencies in power generating technologies were treated in separate sections.

The EIA provides an analysis of three policy and technology scenarios to predict potential changes in future energy use. The scenarios include a 2005 (no change) case, a high technology case, and a best available technology case. Each is measured against a reference case, which represents a baseline of energy use, technology development and policy trends.

The EIA scenarios look at the penetration of alternative technologies that can alter the energy use and demand trends in each of the sectors. In the residential and commercial sectors, it is projected that the use of advanced distributed generation technologies and better use of waste heat from electric power generation facilities can offset space heating energy demands. In the industrial sector, more efficient manufacturing and industrial processes have the potential to further reduce energy demands, including electric power demands. Improvements in end-use efficiencies, as well as conservation have the potential to further reduce the demand for electric power in all sectors in the future.

The potential impact of end-use efficiency and conservation is incorporated into scenario modeling later in this analysis.

VI. Electric Power Generation Technologies

The following power production technologies were considered for this analysis.

A. Wind

Although wind represents a small percentage of the region's total net generation, it represents one of the fastest growing energy sources in the region.[9] From 1997 to 2001, electric power generation from wind grew by an average of 102 percent annually. Although EIA's State Energy Data Report currently provides data through 2001, more recent data from the American Wind Energy Association (AWEA) suggests that rapid growth has continued since 2001. The EIA estimated that in 2003 wind generation capacity in the region totaled 1,237 megawatts (MW). This estimate appears low, as AWEA's most recent data, released in January 2005, estimates regional capacity at 1,748 MW. Although AWEA cites 30 percent growth in installed capacity nationally, some states in this study's region have even higher growth, with some states showing growth of over 100 percent per year. In a ranking of the top ten wind states in the country, 6 of the states in our study region are in the top ten.[10]

Annual wind generation capacity growth rates of 100 percent per year are a function of the low initial installed capacity of wind power in the power generation sector. Utility-scale generation of electricity from wind was non-existent until just over 10 years ago. Until 1994, net generation from wind stayed below 900 MWh (less than 1 MW), except for a burst of activity in the early 1980's that subsequently declined. In 1994, net generation for the region rose to 120,000 MWh (approximately 40MW) per year from 600 MWh (less than 1 MW) per year the previous year.

Wind has enormous potential for additional growth in the U.S. and in the Upper Midwest region. The Pacific Northwest National Laboratory model calculates the wind resource potential of every square kilometer of land in the United States by integrating meteorological data with landform data in a Geographic Information System (GIS)[11].[12] This model assigns a wind class ranking from one to six for each square kilometer of landmass. Wind class rankings of four, five and six are considered appropriate for utility-scale wind development. The model has been validated

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[9] Although wind is the clear winner for 5 year average growth rate, is loses out to residual fuel oil for a 3 year growth rate. Although wind grew by an average of 30% over a 3-year period, residual fuel oil grew by 33% in all sectors, and 116% in the electric power sector.

[10] C. R. D. A. Randall Swisher, Julie Clendenin, Proceedings of the IEEE 89, 1757 (December 2001, 2001).

[11] M. N. S. D.L. Elliott, in International Academy of Science. (Kansas City, MO, 1993).

[12] L. L. W. D. L. Elliot, and G. L. Gower, "An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States" (Pacific Northwest Laboratory, 1991).

through a comparison of predicted wind resources with actual wind measurements.[13] Assuming 5 MW of wind power capacity per square kilometer of land, and excluding land considered inappropriate for wind development (including cities, roads, forested land, water, and others), the model calculates the total developable wind resource for each state.

The model predicts that nearly 608 GWa of wind power capacity could be developed in the U.S. portion of the Upper Midwest study region, assuming capacity factors appropriate for the wind zone.[14][15] This translates into approximately 5,225 TWh of electric power per year, or about 12 times regional net generation in 2003. These estimates help define the upper limit for wind power capacity in each state, and in the region. As Figure 14 illustrates, even with conservative growth in wind capacity over the next fifty years, the region's wind resources would exceed regional demand for electricity by 2030. Even with 10 percent annual growth (growth is currently 30% nationally, and much higher in some states in this region), wind power can fulfill 59 percent of projected regional electricity demand in 2055.

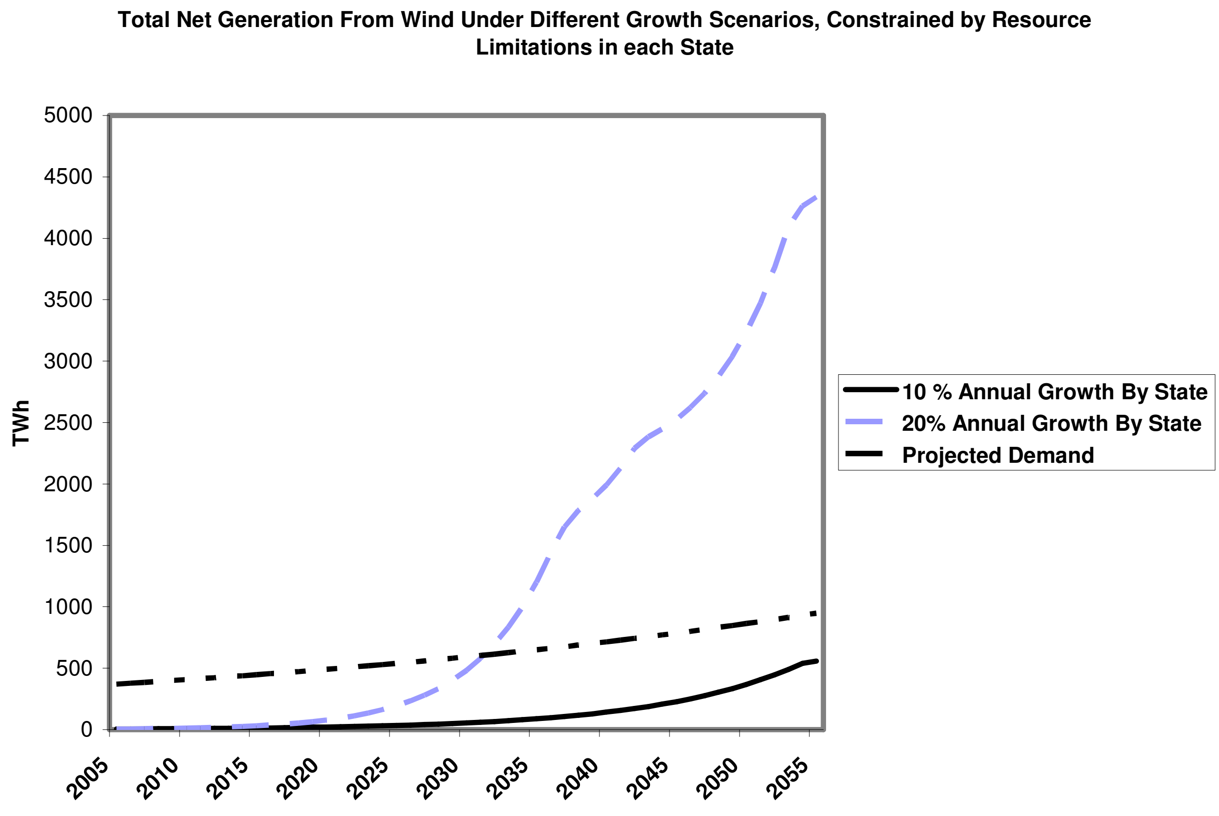

Figure 14: The figure demonstrates the effect of allowing wind to grow (per state) at 10 and 20 percent per year for

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[13] M. Schwartz, in ASES Solar '99 Conference. (Portland, ME, 1999).

[14] MWa: Mega Watt average. Wind is a variable source of power, in this region operating at an average of 33.3% capacity. NREL's figures do not reflect nameplate capacity, but rather an average capacity that accounts for the variability of wind in each wind class. Since NREL's numbers are already adjusted for wind variability, further calculations can assume 100% capacity.

[15] C. G. H. D. L. Elliot, W. R. Barchet, H. P. Foote, and W. F. Sandusky, "Wind Energy Resource Atlas of the United States" Tech. Report No. DOE/CH 10093-4 (Solar Energy Research Institute, 1987).

the next 50 years. Since each state in the region has limited wind resources, growth is bounded at the upward constraint of the wind resource in each state, hence the curvy lines.

Wind's recent growth is due to a combination of policy and economics. A primary driver is advances in wind technology that have driven down the cost. They include increased wind turbine size, reduced turbine weight, manufacturing economies of scale, improvements in power electronics and control systems, and improvements in blade design. These factors result in both lower priced power and higher availability. Wind delivered cost has decreased by about 90% since the early 1980s. Wind turbines in good wind sites typically have availability of 40% or higher, where availability in the 20s or lower was once typical.[16]

Although wind power is not constrained by the total regional resource, there are a variety of constraints on wind development ranging from regulatory rules, structure and culture of the electric power generation industry, economic barriers to expansion, and limitations of the existing transmission system. Several recent studies analyzing the potential of adding wind transmission to the grid in the Upper Midwest region are summarized in a report to Congress issued May 2004[17][18]. Key findings include:

- The Midwest region's (and the entire nation's) transmission system is generally constrained, and improvements will be required to add any new large capacity, wind or otherwise, to the grid. Without major investments, quantities in the range of 1,000 MW or less can be added to the existing system.
- The best wind resources are hundreds of miles from major metropolitan areas, where demands are highest. Although there are additional costs associated with transmission improvements needed to use these resources, it may be more cost effective to use the better, often remote wind resources and pay for transmission than to use poorer quality wind resources closer to large demand centers.
- Because of the variability of wind, the economics of adding new transmission are improved by pairing wind with other power generation. The current conventional choice, because of economics and shared geography, is coal-based power generation.
- Although transporting power over long distances can challenge system stability, the existing Midwestern energy system is characterized by large generation facilities located far from load centers, and relies on long-distance transmission.
- Because of the interconnectedness of the grid, any new generation can interact with other generation in ways that are difficult to predict. Careful planning will be required to integrate new wind generation.
- Costs associated with transmission system improvements needed to accommodate new wind power capacity range from $300,000 to $500,000 per MW of average capacity.[19]

[16] C. R. D. A. Randall Swisher, Julie Clendenin, Proceedings of the IEEE 89, 1757 (December 2001, 2001).
[17] "Xcel Energy and the Minnesota Department of Commerce: Wind Integration Study- Final Report" (EnerNex Corporation, Wind Logics, Inc., 2004).
[18] "Report to Congress on Analysis of Wind Resource Locations and Transmission Requirements in the Upper Midwest" (Office of Energy Efficiency and Renewable Energy and Office of Electric Transmission and Distribution of the Department of Energy, 2004).
[19] Summarized from Congressional report above.

Beyond the transmission constraints, wind is constrained as a proportion of total net generation in a system. There is some debate about what level of penetration the grid can sustain. In Denmark and some regions of Spain and Germany, 10-25% of total annual electricity generated is from wind. The northern German state of Schleswig-Holstein current meets 25% of annual electricity demand from wind, and up to 50% in certain months.[20]

Several approaches are being studied for increasing the availability and dispatchability of wind.. In one approach, wind power is used to perform electrolysis on water. The resulting hydrogen is used to produce base load power in a fuel cell or combustion application. In another approach, a wind turbine compresses air rather then producing power. Base or peak load power is produced by releasing air with an addition of heat. The commercial success of these approaches could improve the economics of wind power by allowing it to receive higher tariffs for base or peak load power. There is also potential to balance the variability of wind through geographic dispersion of wind capacity, under the principle that the wind is always blowing somewhere.[21]

B. Solar-Electric

There are several electric-generation technologies that convert sunlight into electricity. They include concentrating solar systems such as parabolic trough collectors, power towers, and dish/engine systems as well as photovoltaic systems.

Concentrating solar systems are not currently cost-competitive, with electricity costs currently ranging from 10-18 cents per kWh. They are projected to be cost-competitive by 2020, ranging from 3.5-5.8 cents per kWh. Photovoltaic systems are even less cost-competitive. They currently deliver power from 24-30 cents per kWh (or about $500/kW). It is generally assumed that $150/kW is the "breakeven" price at which PV is cost-competitive without subsidies.[22]

The National Renewable Energy Lab's Center for Renewable Energy Resources publishes data on solar resources for the United States. There are no areas in the study region that have been categorized as ideal for development of concentrating solar power systems.

If technological breakthroughs significantly lower the cost of PV, then there is enormous potential in the region. This study, however, assumes current costs. At current costs, PV is unlikely to constitute a large share of regional power generation without policy interventions.

C. Biomass

As with other resources, the first steps in determining the potential for the resource within the study region is to determine the physical constraints and limits to development. There is a large literature dedicated to determining the quantity of biomass that could potentially be produced in the United States. The Department of Energy just completed their "Billion Ton Study" which was aimed at determining whether the U.S. could produce enough biomass to replace 30% of

[20] D. M. Kammen, paper presented at the 20-50 Solution: Technologies and Policies for a Low Carbon Future., Washington DC, March 24-25 2004.
[21] R. A. Michael Milligan, in *Windpower '98*. (Bakersfield, CA, 1998).
[22] L. K. John Byrne, Daniele Poponi, Allen Barnett, *Energy Policy* **32**, 289 (2004).

projected annual petroleum consumption in 2030.[23] The answer was yes. According to this analysis, which incorporated models developed over the past 15 years by the Oak Ridge National Laboratory and other government entities, there is the potential to develop 368 million dry tons of sustainably removable biomass from forestlands, and 998 million dry tons from agricultural lands, for a total of more than 1.3 billion tons, nationally. The forestland biomass includes fuel wood harvested from forests, residues from wood processing mills and pulp and paper mills, urban wood residues, and other residues. The agricultural biomass includes crop residues, perennial energy crops, grains, and animal manures and other residues.

An earlier study, drawing on the same data sources, also included estimates of the amount of biomass that could be obtained at different prices, and provided a state-by-state breakdown of the estimates.[24] Although the national resource estimate was lower in this study (around 500 million dry tons compared to 1.3 billion dry tons), the link to price is much more informative for analysis purposes.

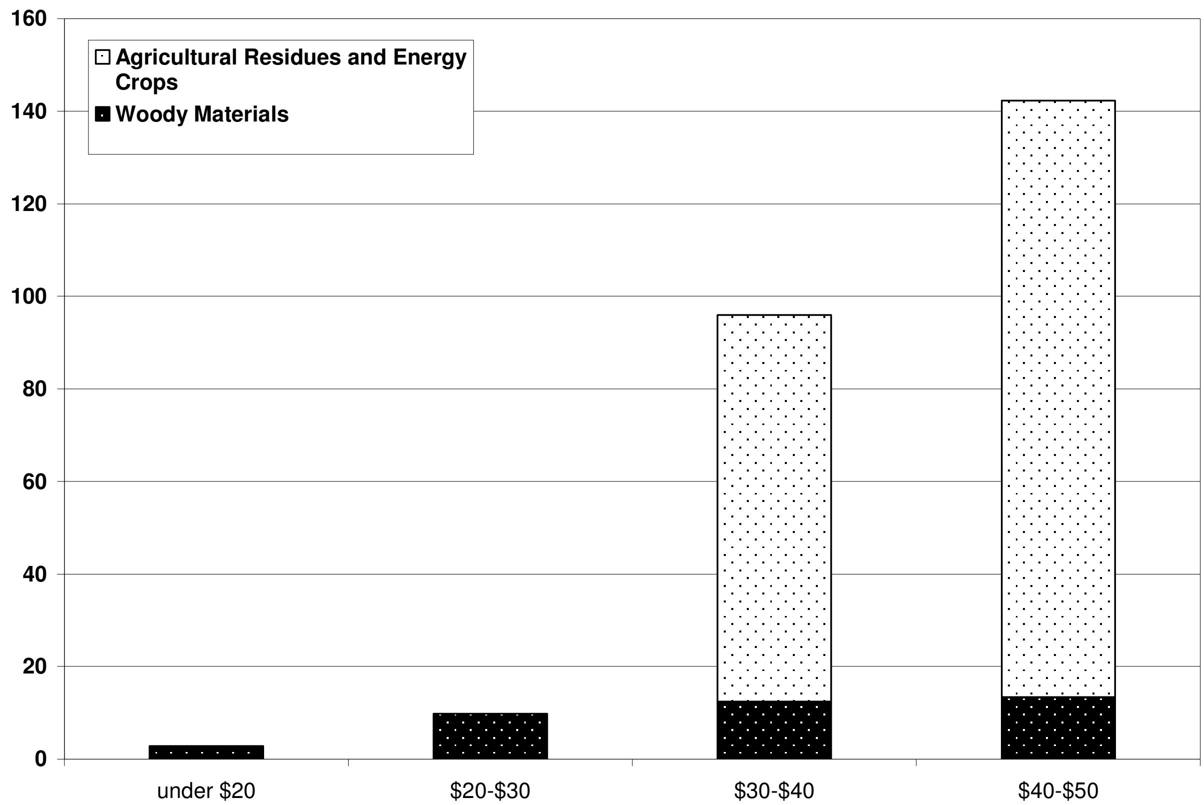

Figure 15 : Tons of biomass available in region at various costs. Assumes no significant disruption in the cost and supply of food.

23 L. L. W. Robert D. Perlack, Anthony F. Turhollow, Robin L. Graham, Bryce J. Stokes, Donald C. Erbach, (2005).
24 D. G. D. L. T. U. Marie E. Walsh, Hosein Shapouri, Stephen P. Slinsky, Environmental and Resource Economics 24, 313 (2003).

Currently production of electricity from biomass represents less than 1% of net generation, and is largely limited to the use of waste wood from the wood products industry which can be obtained at low zero or even negative cost (assuming an averted tipping fee). The use of biomass for power was encouraged during the Carter administration in response to an energy crisis. Use of biomass doubled between 1975 and 1980, after many years of relatively show increase. Growth in biomass consumption for electric power peaked in 1983-84 and then began to decline. Although use of biomass is still higher than it was in 1976, it continues to decline and is at roughly half its maximum consumption in the early 1980s.

Using EIA's estimates for the capital and operating costs of biomass Integrated Gasification Combined Cycle and assuming $50 per ton biomass, we arrive at a plant gate cost of power at $55 per MWh.[25] [26] This is not quite twice as costly as power from hydroelectric ($30), nuclear ($32), and wind ($34).

The cost of biomass power is highly dependant on the cost of biomass fuel. If you reduce the cost of fuel to around $10 per ton, biomass is cost competitive with the other sources of carbon-neutral power above. If the cost is reduced further, then it is cost-competitive with a pulverized coal plant (depending on variables such as plant size and coal cost). This likely explains the continued existence of a biomass power industry associated with the wood products industry, where waste wood can be obtained at little or no cost.

One factor that could influence the economics of biomass is the possibility to produce a wide variety of higher-value co-products in addition to electric power. These products include, in order of their value: heat, liquid fuels, and bulk chemicals. The Department of Energy proposes a model known as an "integrated biorefinery" wherein biomass is used in a process analogous to a petroleum refinery to produce as wide variety of valuable energy and non-energy products. This would be very likely to change the overall economic picture in favor of larger scale electrical production.

Another factor is the potential for carbon payments. Many analyses of the carbon impact of using biomass for power assume that the carbon balance is zero, or in other words that the amount of carbon emitted in burning the fuel was absorbed in growing the fuel. This is, of course, highly dependant on the practices used. If fossil fuels are used in growing, transporting, or processing the fuel, then the carbon balance is actually positive. If the biomass is grown in such a way that soil health is not maintained and carbon is released, then the carbon balance is also positive. If the biomass was grown in such a way that below-ground biomass is added, then the carbon balance is actually negative or in other words for every unit of power generated, carbon is actually taken out of the atmosphere. In a carbon-constrained world where there are financial incentives for reduced carbon energy, these assumptions are very important. Carbon payments for terrestrial sequestration could significantly lower the production cost of a ton of biomass and improve the overall economics of power production.

[25] W. A. A. R.L Bain, M. Downing and R.L. Perlack, "Biopower Technical Assessment: State of the Industry and Technology" (2003).
[26] "Power Technologies Databook" (National Renewable Energy Laboratory, 2003).

While the impact of soil sequestration on the economics of biomass power is important, it is beyond the scope of this study. This issue should be explored in more detail. For now, assuming that biomass power is carbon-neutral is reasonable and consistent with many other studies.

D. Hydroelectric

In 2004 there were 52 utility-scale hydroelectric power facilities operating in the region. These facilities contributed approximately 50.5 TWh of total net generation in the region, nearly 12 percent of the region's total generation in 2004, the third largest source of power behind coal and nuclear. Hydroelectric generation dominates power production in Manitoba. Fourteen facilities in Manitoba accounted for over 31 TWh, or over 60 percent of the region's net hydroelectric generation in 2004. Manitoba supplies more than 99% of its own power by its hydroelectric facilities, in addition to exporting power both within Canada and to the US.

The Department of Energy (supported by the Idaho National Laboratory) has evaluated the potential hydroelectric capacity for each state and compared it with existing developed capacity. After excluding a portion of the undeveloped capacity based on a series of criteria, the Idaho National Laboratory data shows that additional capacity can be developed in almost every state in the study region.[27] [28]

Manitoba Hydro, the Canadian Crown Corporation that controls all electric power generation in Manitoba, has also conducted resource evaluations. According to sources within Manitoba Hydro, there is the potential to ultimately develop over 5,000 MW of hydroelectric generation capacity in Manitoba, including over 2,000 MW in the next 20 years.

Table 4 summarizes additional hydroelectric power potential in the study region.

Table 4:
Undeveloped Hydroelectric Power

State/Province	Undeveloped Capacity (MW)
Illinois	1,598
Iowa	902
Minnesota	1,033
Montana	3,008
North Dakota	11
South Dakota	169
Wisconsin	1,142
Wyoming	3,173
Manitoba	5,000
Total	16,016

Sources:

[27] http://www.hydropower.inl.gov/resourceassessment

[28] J. E. F. Alison M. Conner, Ben N. Rinehart, "U.S. Hydropower Resource Assessment Final Report" (1998).

If all the hydroelectric capacity were developed in the region, an additional 16,016 MW of capacity, or around 70 TWh could be produced, assuming a 50 percent capacity factor. High-power, high-head hydroelectric development potential alone is around 10,973 MW, or around 48 TWh of generation potential.

Demand for power in the region in 2055, assuming 1.9 percent demand growth per year, is estimated at 948 TWh. If all hydroelectric power were developed in the region, and all existing capacity was maintained, it could supply approximately ten percent of projected demand in 2055. Hydroelectric power, while relatively low in cost and carbon neutral, represents a small proportion of total regional power generation potential.

Table 5: Cost estimates for conventional hydropower

Technology	Installed Cost ($/MW Capacity)[29]	Fixed O&M ($/kW)	Heat Transfer Efficiency (%)	Net CO_2 Emissions (tonnes/ MWh)	Power cost ($/MWh) (Plant gate)
Conventional Hydro (turbine)	1,451,000	12.35	N/A	0	$29.9

E. Coal

An analysis of the region's energy system reveals that coal plays a major role in electrical power generation. Many studies predict that coal will remain an important element of the future energy mix, given coal's availability in the U.S., concerns about national security, and the extent of coal-based generation infrastructure. However, for coal to hold its place in the regional energy system in this study, significant emissions reductions would need to be achieved.

According to data collected for the electricity generation sector inventory, over 183 million tons of coal was used for power generation in the study region in 2004. Power generation from coal accounted for more than 65 percent of the net generation in the study region in the same year. Over half of the total net generation was produced using sub-bituminous coal. Anthracite, bituminous, and lignite coals accounted for 13 percent of the remaining mix. Coal-fired steam turbine generation was the predominant coal power technology.

Coal-fired power generation is the largest source of carbon dioxide emissions in the region. Emissions data from 2000 indicate that coal used for electric power generation accounted for 289 million metric tonnes, or 43 percent of total carbon dioxide emissions from all sectors in the study area, making this an obvious emissions-reduction target.

Coal is viewed as a reliable future source for the nation's energy systems. Based on data presented by the Energy Information Administration (EIA), there were more than 500 billion tons of coal reserves in the United States as of January 1, 1997.[30] Approximately half, or 275 billion short tons were considered recoverable, based on estimates of coal accessibility and

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[29] $1700 – 2300 according to Idaho National Laboratory
[30] Energy Information Administration, U.S. Coal Reserves: 1997 Update, http://www.eia.doe.gov/cneaf/coal/reserves/highlights.html

mining recovery rates. This measure of recoverable coal represents approximately 250 times 1997 U.S. coal production. Low-sulfur coal accounts for 36 percent of recoverable reserves. Medium- and high-sulfur coals account for 31 and 33 percent of recoverable sources, respectively.[31] Almost half of the recoverable coal resources are found in the western United States, including significant deposits in North Dakota, Wyoming and Montana. Illinois and Iowa also contain significant coal reserves within the study region. Although Canada holds an estimated 7.2 billion tons of recoverable coal reserves[32], coal for electricity generation in Canada is generally imported from the United States.[33] There are no significant recoverable coal deposits in Manitoba.[34]

Current coal-based power generating technologies can be improved in terms of carbon dioxide emissions through efficiency improvements in the conversion of coal to electricity. These improvements can be achieved through improved materials, process design, and turbine design. It is estimated that these types of improvements can increase the efficiency of steam-turbine plants from 33 percent up to 42 percent. Current advanced coal combustion technologies include supercritical pulverized coal, ultra-supercritical pulverized coal, and supercritical circulating fluidized –bed combustion.

Many of the newer technologies currently being deployed either as new plant processes, or as retrofits to existing plants are focused on reducing pollution from NOx and SOx, and improving the efficiency of the coal plants. Circulating fluidized bed combustion technologies target NOx and SOx reduction. Supercritical and ultra-supercritical boiler technologies enhance traditional pulverized coal and circulating fluidized bed technologies by allow higher steam pressures and pressures, which leads to improvements in thermal conversion efficiencies. Supercritical steam processes have efficiencies that are, on average, three to four percentage points higher than traditional coal-burning processes. Ultra-supercritical processes can increase the efficiency of power generation by as many as eight percentage points. For every one percent increase in thermal efficiency, carbon dioxide emissions are reduced by approximately two to three percent for the same amount of electricity produced.

Integrated gasification combined cycle (IGCC) technologies offer higher operating efficiencies than traditional coal combustion technologies. Pilot IGCC units operate at efficiency levels approaching 45%, compared with traditional and enhanced coal combustion units that achieve 33 to 41 percent efficiencies.

Costs and carbon dioxide emissions rates for advanced coal-powered technologies are summarized in Table 6.

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[31] Energy Information Administration, U.S. Coal Reserves: 1997 Update, http://www.eia.doe.gov/cneaf/coal/reserves/highlights.html
[32] http://www2.nrcan.gc.ca/es/ener2000/online/html/chap3e_e.cfm
[33] http://www.eia.doe.gov/emeu/cabs/canada.html
[34] http://www2.nrcan.gc.ca/es/ener2000/online/html/chap3e_e.cfm

Table 6 Costs and Characteristics of Coal Technologies					
Technology	Heat Transfer Efficiency (%)	Installed Cost ($/MW capacity)	Fixed O&M Costs ($/kW)	Non-Fuel Variable Costs ($/MWh)	CO2 Emissions (tonnes/ MWh)
Advanced Bituminous & Anthracite	39%	$1,213,000	$24.36	$3.09	0.82
Advanced Sub-bituminous	39%	$1,213,000	$24.36	$3.09	0.85
Advanced Lignite	39%	$1,213,000	$24.36	$3.09	0.87
Bituminous IGCC	41%	$1,402,000	$34.21	$4.88	0.77
Sub-bituminous IGCC	41%	$1,402,000	$34.21	$4.88	0.80
Lignite IGCC	41%	$1,402,000	$34.21	$4.88	0.81

Source: *Energy Information Administration/Assumptions to the Annual Energy Outlook 2005, <http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf >.*

An analysis of the coal-fired power production facilities in the region reveals opportunities for replacement of existing plants. Assuming an operational lifetime of 50 years for each unit, all of the existing power generating capacity in the region will be up for retirement by 2055. Figure 16 illustrates the pattern of possible plant retirements in the region.

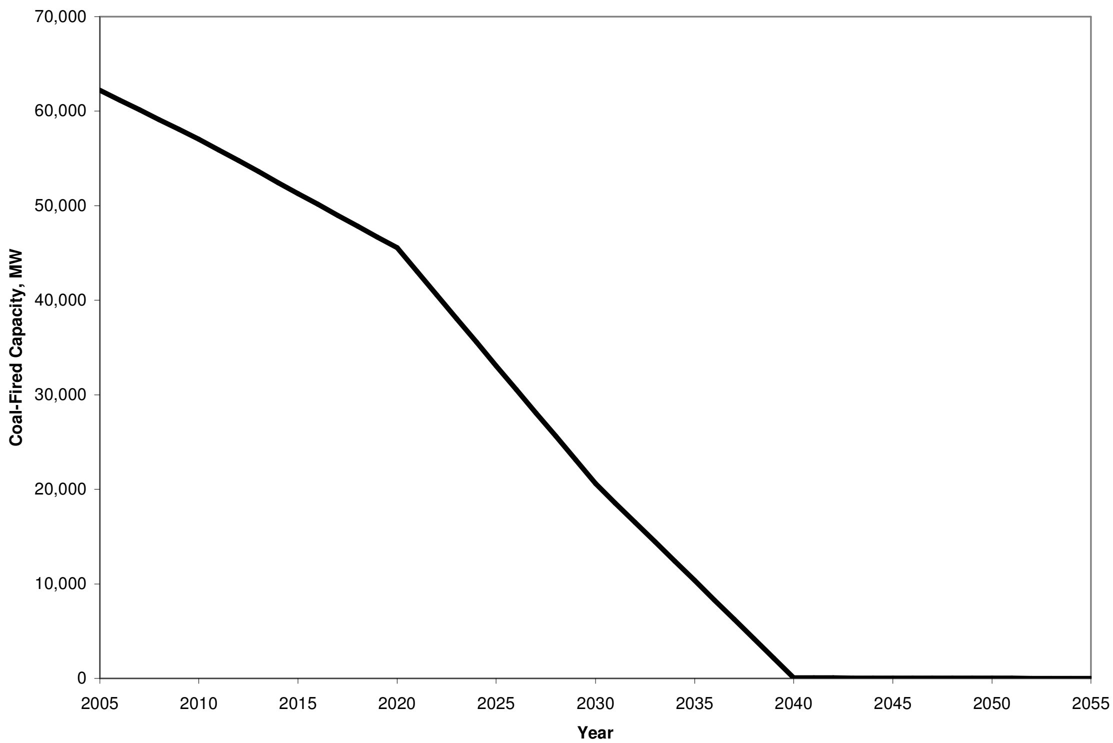

Figure 16: Retirement of coal-fired capacity in the region, assuming a 50 year plant life.

The goal of reducing carbon dioxide emissions to 20 percent of 1990 levels by 2055 demands a dramatic reduction in traditional coal-fired power generation. Research has shown that on a national scale, re-powering existing pulverized coal combustion plants with IGCC technology would not achieve even 1990 emissions levels.[35] In fact, even with improved efficiencies and advanced technology deployment, emissions would continue to increase due to continued overall growth in electricity demand and generation.

The same is true for the study region. An analysis of the existing coal-fired electricity generating facilities reveals that even if all coal-fired power generation stations were re-powered with IGCC technologies operating at 45 percent efficiency, emissions in 2004 would still have been nearly 1.8 times higher than the study target. This analysis did not account for new capacity to meet projected demands, emissions from other power generating fuels, or emissions from any other sectors. Existing generation capacity must be replaced with more efficient fossil fuel-based technologies, provided with carbon capture and sequestration technologies to reduce carbon dioxide emissions, or supplanted by carbon-neutral energy sources and technologies in order to meet the study goals. A discussion of carbon capture and sequestration technologies is included in the following section.

F. Carbon Capture and Sequestration

Geologic sequestration, which involves injection of a stream of carbon dioxide into oil and gas reservoirs, unmineable coal seams, and deep saline formations, is considered a near-term option for long-term storage of carbon dioxide produced from anthropogenic sources. It is projected to be the first application for sequestering carbon dioxide from power plant emissions, and because of the relative proximity between power plants and geologic sequestration sites, it is assumed to be the most appropriate for the region.

The National Energy Technology Laboratory estimates that domestic oil reservoirs and unmineable coal seams present the most near-term and least costly options for sequestration.[36] The storage capacity of domestic oil and gas reserves is estimated at 150 billion metric tons of carbon dioxide, roughly 30 times current U.S. emissions. The storage capacity of domestic unmineable coal seams is estimated at 90 billion metric tons of carbon, which includes 40 billion metric tons in Alaska. The potential for saline formations is estimated at 500 billion metric tons.[37] For comparison, carbon dioxide emissions from the study region were estimated at 674 million metric tons in 2000.

Potential geologic storage sites are located throughout the United States, and underlie portions of the study region. According to data provided by the U.S. Department of Energy, Pacific Northwest National Laboratory, unmineable coal seams exist in portions of Montana and Wyoming, Iowa and Illinois. Deep saline formations lie beneath large portions of Montana, western North Dakota, western South Dakota, and small portions of Illinois. The only significant gas reservoirs in the study region are in Wyoming.

Storage potential within the study area is being analyzed. Three research partnership groups (Big Sky Carbon Sequestration Partnership, The Plains CO_2 Reduction Partnership, and the Midwest

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[35] Ancillary studies
[36] U.S. Department of Energy, National Energy Technology Laboratory, Carbon Sequestration, Technology Roadmap and Program Plan – 2004, April 2004.
[37] http://www.fossil.energy.gov/programs/sequestration/geologic/

Geological Sequestration Consortium), which were established under the National Energy Technology Laboratory's Regional Partnerships program, are currently working to assess the resources within their geographic regions.

Several field tests and pilot programs have been established to study geologic sequestration, and several options exist for early deployment of these technologies. One of the two larger-scale field tests is being done at Weyburn, Saskatchewan, where carbon dioxide from the Dakota Gasification Facility in North Dakota is injected into a depleting oil reserve, enhancing oil recovery operations. Several other projects of similar or smaller scale are being carried out in other areas of the U.S.

The main challenges associated with sequestration lie not in carbon transport and storage technologies, but in the technical and economic aspects of capturing carbon from anthropogenic sources. In order for carbon dioxide to be sequestered, it must be separated from industrial process streams, combustion flue gas, or synthetic gases (syngas) and then be compressed, transported and injected. Several technologies exist for capturing carbon from stationary sources, and these vary in applicability according to the source. Generally, carbon capture technologies can remove 90 percent of the carbon dioxide from the source.

Carbon dioxide emissions formed from the combustion of pulverized coal are at relatively low concentrations (3 – 15% volume)[38] in combustion flue gases. The state-of-the-art technology for capturing carbon dioxide in this case uses liquid amine absorption. This process requires intensive energy input for regeneration of the amine liquid and compression of the carbon dioxide stream, and can increase the energy input for a coal-fired process by 40% for the same amount of net generation.

In a gasification facility, carbon dioxide is captured from synthetic gases (syngas) before combustion. Syngas has a much higher concentration of carbon dioxide than flue gases (40 – 60% volume) and is provided at much higher pressures. [39] The state-of-the-art technology for this process uses liquid glycol solvents. Capture from syngas does require energy input for gas compression, but overall is a less energy intensive process than post-combustion separation processes.

Membrane technologies, scrubbers, chemical and physical sorbents, and alternative combustion processes, including oxyfuel combustion, are the focus of current research projects aimed at lowering the costs and energy intensity of carbon capture technologies. For wide-scale application of these technologies, scale-up of these technologies, along with more research into the adequacy and risks associated with long-term storage are needed. In particular, study of IGCC with carbon capture using sub-bituminous and lignite coals in large applications are needed to better understand the costs, efficiencies, and polygeneration potential of this technologies.

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[38] U.S. Department of Energy, National Energy Technology Laboratory, Carbon Sequestration, Technology Roadmap and Program Plan – 2004, April 2004.
[39] U.S. Department of Energy, National Energy Technology Laboratory, Carbon Sequestration, Technology Roadmap and Program Plan – 2004, April 2004.

The cost for carbon capture varies with the carbon dioxide source. Data reported by the EIA indicate that carbon capture from industrial sources with high-purity carbon dioxide stream, is the less costly than capture from any of the current or near-term power generation technologies.[40] For this study, coal IGCC was assumed to be the primary technology that would likely be matched with carbon capture and sequestration, as cost data show that this method is less costly than capture associated with advanced pulverized coal, or NGCC technologies.[41] Data presented by the National Energy Technology Laboratory indicates that adding liquid amine carbon capture technology to a newly-built pulverized coal plant will increase the cost of electricity by 84 percent, from 4.9 cents/kWh to 9 cents/kWh.[42] Adding a liquid-glycol-based carbon dioxide capture process to a newly-built IGCC plant will raise the cost of electricity by 25 percent, from 5.5 cents/kWh to 6.5 cents/kWh.[43] A similar study by Herzog and Golomb indicate that carbon capture can add 2-4 cents/kWh to the cost of electricity from pulverized coal plants, 1-3 cents/kWh to the cost of electricity from IGCC plants, and that the addition of liquid amine absorption technology to an NGCC plant can add 1-2 cents/kWh to the cost of electricity. [44] In addition, although it would be possible to retrofit existing power generation facilities with carbon capture technologies, the incremental cost of adding capture processes to existing plants are higher than the costs of capture processes incorporated into the design of new facilities.

Data provided by the EIA for coal IGCC with carbon capture, which account for 75 to 80 percent of capture and sequestration costs,[45] are summarized in Table 7.

Table 7
Characteristics of Coal Technologies with Carbon Capture and Sequestration (CCS)

Technology	Heat Transfer Efficiency (%)	Installed Cost ($/MW capacity)	Fixed O&M Costs ($/kW)	Non-Fuel Variable Costs ($/MWh)	CO2 Emissions (tonnes/ MWh)
Bituminous IGCC with CCS	35%	$2,006,000	$40.26	$7.66	0.09
Sub-bituminous IGCC with CCS	35%	$1,402,000	$34.21	$7.66	0.09
Lignite IGCC with CCS	35%	$1,402,000	$34.21	$7.66	0.10

Source: *Energy Information Administration/Assumptions to the Annual Energy Outlook 2005, <http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf >.*

Where carbon dioxide sources and geologic sequestration sites do not overlap, the carbon dioxide stream must be transported for remote or off-site sequestration via pipeline. Based on the location of potential geologic sequestration sites in the study area, and the current level of experience with large-scale injection, it is likely that sequestration of carbon dioxide from power generation will occur first in oil reserves. Expansion into the coal seams and deep saline formations will follow as research and pilot scale applications demonstrate that these are

[40] Energy Information Administration, <http://www.eia.doe.gov/oiaf/1605/ggrpt/geologic.html>.
[41] Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/ggrpt/geologic.html.
[42] http://www.netl.doe.gov/coal/Carbon%20Sequestration/kidspage/index.html
[43] http://www.netl.doe.gov/coal/Carbon%20Sequestration/kidspage/index.html
[44] H. Herzog, D. Golomb, Carbon Capture and Storage from Fossil Fuel Use, The Massachusetts Institute of Technology Laboratory for Energy and the Environment, <http://sequestration.mit.edu/pdf/enclyclopedia_of_energy_article.pdf>
[45] Energy Information Administration, < http://www.eia.doe.gov/oiaf/1605/ggrpt/geologic.html>.

adequate storage reservoirs. The estimated cost of transportation via pipeline and injection ranges from \$3 – \$5.50 per metric ton of carbon dioxide emissions avoided.[46] Separate costs for transport and injection are broken out in Table 8.

Table 8 Carbon Dioxide Transport and Injection Costs	
	Cost/Tonne CO_2 Emissions Avoided
Carbon Transport Costs (100 km via pipeline)	\$1 - \$3
Carbon Injection Costs	\$2 - \$2.50

Source: http://www.eia.doe.gov/oiaf/1605/ggrpt/geologic.html

A study presented at the Gasification Technologies Conference in 2003[47] reported that the costs of carbon capture associated with gasification of coal for electricity generation, as with IGCC, will depend on the gasification technology, as well as the type of coal. The report shows that while the majority of the studies show that IGCC capture costs are lower than pulverized coal capture costs, these analyses use bituminous coals as the fuel source. This study indicated that using current gasification technologies, the cost of energy for IGCC with carbon dioxide capture is close to the cost of energy from pulverized coal plants with sub-bituminous coal, and may be higher with lignite coal. Larger scale application of gasification technologies with sub-bituminous coal and lignite will yield refined estimates for capture and sequestration costs.

Potential for value-added products associated with carbon dioxide storage, such as enhanced oil recovery, and enhanced coal bed methane recovery, should be considered in evaluating the costs for sequestration. In these applications, the costs associated with carbon capture can be partially offset by the market value of the carbon dioxide stream. Studies indicate that a break-even point for carbon capture and sequestration occurs at a price of \$12.21 per ton of carbon dioxide.[48] While opportunities exist to offset the price of carbon sequestration in oil, gas, and coal bed formations, there currently are no opportunities to derive value-added products from injection into saline formations.

Carbon capture and sequestration technologies have the potential to reduce regional carbon dioxide emissions. However, whether or not these technologies can achieve the goals of this study depends on the rate of expansion of coal as a fuel source for electric power generation in the region. If no more coal-fired generation was added to the current system, and all existing units were transformed into IGCC units with sequestration, carbon dioxide emission reductions could be reduced from 225 million tonnes to 25.3 million tons.[49] If coal-fired generation remains at 66 percent of total net generation, and all existing and new units used IGCC with sequestration technologies, then carbon dioxide emissions would reach 56.25 million tonnes in

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[46] Executive Summary – find source
[47] N. Holt, G. Booras, D. Todd, A Summary of Recetn IGCC Studies of CO2 Capture for Sequestration, presented at The Gasification Technologies Conference, San Francisco, California, October 12-15, 2003.
[48] H. Herzog, D. Golomb, Carbon Capture and Storage from Fossil Fuel Use, The Massachusetts Institute of Technology Laboratory for Energy and the Environment, <http://sequestration.mit.edu/pdf/enclyclopedia_of_energy_article.pdf>
[49] Using net generation of 281,280 GWh in 2005, assuming 0.8 tonnes CO2/MWh in 2004, and 0.09 tonnes/MWh in 2055 using IGCC with capture and sequestration.

2055.[50] To meet the goals of this study, total carbon dioxide emissions from the power generation sector would be limited to 47 million tonnes in 2055.

G. Natural Gas

In the Upper Midwest region, natural gas is used mainly to meet peak load demands. In 2004, natural gas-fired generation accounted for approximately 2 percent of the total net generation in the region. Carbon dioxide emissions associated with utility-scale gas-fired generation has accounted for between 2 and 13 percent of total power sector emissions in the region since 1960.

The EIA's Annual Energy Outlook 2005 notes that natural gas use in the industrial sector is expected to decline and be replaced by higher demand for electric power. The same is true in the residential sector, where the rise in demand for electricity will outpace the rise in demand for natural gas. The use of natural gas in the electric power generation sector is expected to increase in the future.[51] The EIA notes that variations in the price of natural gas will affect its use as an energy source in all sectors.

Natural gas supply in the U.S. is made up of domestic production and imports. In the study region, most imports come from Canada via several distribution points along the U.S./Canada border in Minnesota, North Dakota and Montana. Domestic gas production in the study region is found in the western states. North Dakota and Montana produce a small portion of the domestic supply, and there is significant production in Wyoming. Estimates of natural gas reserves indicate that domestic natural gas production is expected to rise, due mainly to an increase in production from unconventional reserves. Imports to the U.S. from Canada are projected to remain relatively constant. Imports of liquid natural gas from overseas is expected to increase significantly over the next several decades.

There are primarily three technologies used to produce electricity from natural gas: steam turbines, gas turbines and combined cycle (NGCC) units. Steam turbine generation from gas is less common than steam turbine generation from coal or nuclear fuels. These units operate at heat transfer efficiencies of 33 to 35 percent, comparable with coal-fired generation, but less efficient than other gas-fired technologies. Within the study region, less than 20 percent of natural gas-fired electric power production in 2004 was generated with steam turbine units.

Gas turbine units accounted for more than 37 percent of the gas-fired electric power generation in 2004. Gas turbines typically achieve heat transfer efficiencies of 30 percent, slightly less than steam-driven units. These units are typically used to meet peak demand, as they can be powered up with relative speed and ease, and because of their relatively low construction, yet high fuel costs compared with other technologies.

Combined cycle, or NGCC plants operate at heat transfer efficiencies of between 45 and 50 percent. This technology has been selected for many new facilities, and has been retrofitted to

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[50] Using net generation of 625,000 GWh in 2055, and 0.09 tonnes/MWh in 2055 using IGCC with capture and sequestration.
[51] Energy Information Administration, Annual Energy Outlook 2005, <2005, http://www.eia.doe.gov/aoif/aeo/demand.html>.

existing steam generation units, due to the higher efficiencies that can be achieved. In 2004, there were twelve NGCC facilities operating in the study region, which accounted for 43 percent of the total gas-fired utility power generation.

Natural gas-fired power generation is less carbon intensive than coal-fired power generation. Carbon dioxide emissions associated with NGCC technologies average 0.36 tonnes per MWh, while emissions from coal-fired generation range from 0.77 t0 0.87 tonnes per MWh.[52] Natural gas power generation technologies may continue to play an important role in meeting peak demands, or as a cleaner alternative than coal in matching other technologies like wind power. Re-powering or replacing coal-fired power units with NGCC units could reduce carbon dioxide emissions by 40 to 50 percent.

However, even the relative advantages of lower carbon dioxide emissions rates with NGCC over conventional coal technologies are not significant enough to meet emissions goals of this study. Even if all the coal-fired generation in the study region in 2004 were replaced with NGCC, carbon dioxide emissions would have been reduced by only 40 percent. To meet the level of emissions reduction targeted in this study, carbon capture technologies would need to be paired with NGCC units to further reduce carbon dioxide emissions.

Costs and characteristics for NGCC power generation technologies are summarized in Table 9.

Table 9
Costs and Characteristics of NGCC Technology

Technology	Heat Transfer Efficiency (%)	Installed Cost ($/MW capacity)	Fixed O&M Costs ($/kW)	Non-Fuel Variable Costs ($/MWh)	CO2 Emissions (tonnes/ MWh)
NGCC	52%	$567,000	$11.04	$12.60	0.36

Source: *Energy Information Administration/Assumptions to the Annual Energy Outlook 2005, <http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf >.*

Adding carbon capture processes to a new NGCC facility would add an estimated $428 per kW of capacity, and increases the cost of electricity by approximately 45 percent.[53] Carbon capture and sequestration is paired with coal IGCC electric power production in this study because of the cost advantages associated with capture from IGCC technology over NGCC technology. However, for meeting peak-load demand, carbon capture and sequestration from gas-fired units may prove to be an effective means of achieving further emissions reductions.

H. Nuclear

Whether or not nuclear power generation will continue its role in the region's energy system depends on more than emissions, costs, and the state of the technology. Storage issues, risk and politics will likely factor more heavily into the discussion of nuclear energy than the more

[52] Energy Information Administration/Assumptions to the Annual Energy Outlook 2005, <http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf >.
[53] http://sequestration.mit.edu/pdf/David_and_Herzog.pdf

technical aspects of the technology. However, this study considers only the impact that nuclear energy has on carbon dioxide emissions from the region.

There are currently eighteen nuclear power units operating at eleven sites within the study region. These units have a total capacity of over 15,800 MW. In 2004, these units provided more than 107 million megawatt-hours, or 25 percent of the region's total electricity production. The average operating capacity factor for all of the units in the region was 78 percent.

All of the region's nuclear power units were brought online between 1970 and 1988, and all licenses will expire by 2032 with the earliest scheduled retirement in 2009. A summary of the regional nuclear generating capacity, and license retirements are shown in Figure 16 .

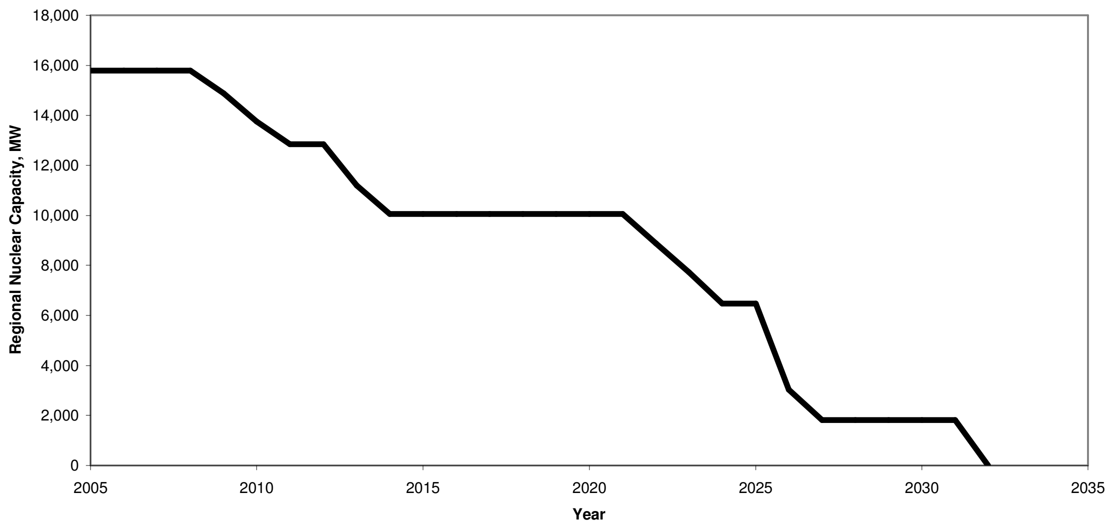

Figure 16: Retirement of regional nuclear plants, assuming a 50 year life.

All nuclear reactors used for commercial operation in the U.S. are light water reactors. Several alternative reactor designs, including gas-cooled reactors, fast breeder reactors and heavy water reactors are in commercial operation in other parts of the world. Research into new, more advanced reactor designs is underway in several countries, including the U.S. These new designs, which include other gas-cooled, and molten metal-cooled designs are generally more economic and simplified designs and have improved safety concepts over earlier designs.

The utilization capacity of nuclear facilities has risen nationally over the past two decades. In 1989, the national average capacity factor for nuclear facilities was 62 percent. In 2004, that measure had risen to over 90 percent, indicating that downtime for nuclear facilities is declining. A corresponding increase in the share of power generation from nuclear facilities has followed this trend.

The EIA reports that no new nuclear facilities have been added to the U.S. energy system since 1996 and predicts that none will be added before 2025, although the Nuclear Regulatory

Commission expects license renewal applications for many operating reactors in the coming years.[54]

Relative to traditional fossil fuel-powered generation, the construction costs and operating costs for nuclear facilities are relatively high. According to data from the Energy Information Administration, construction of a new nuclear plant is estimated at $1,957 per kW of installed capacity. Fixed annual O&M costs are estimated at $60.06 per kW. Non-fuel variable costs are estimated at $4.22/MWh.[55] The cost of producing energy from nuclear facilities averages 3.1 cents per kWh.

In terms of carbon dioxide emissions, nuclear power generation displaced the equivalent of 106.7 million metric tons of carbon dioxide emissions from coal-fired generation[56] in the region in 2004 (total carbon dioxide emissions from coal-fired production were 289 million metric tons in 2000). Operating at a higher capacity factor, say of 90 percent, the nuclear power units in the region have the potential to displace 123.9 million metric tons of carbon dioxide emissions from coal-fired power generation in the region.

I. Electric Power Generation Technology Summary

A summary of the electric power production technologies discussed in the previous sections is summarized here. Data were obtained from the Energy Information Administration's 2005 Annual Energy Outlook where available. Other sources are noted.

Table 10
Summary of Electric Power Production Technologies

Technology	Installed Cost ($/MW Capacity)	Fixed O&M ($/kW)	Heat Transfer Efficiency (%)	Net CO_2 Emissions (tonnes/ MWh)	Power cost ($/MWh) (Plant gate)
Biomass	1,757,000	47.18	38%	0	$55.6
Municipal Solid Waste / Landfill Gas	1,500,000	101.07	25%	0	$76.9
Bituminous and Anthracite Coal (steam)	1,213,000	24.36	39%	0.82	$22.4
Sub-bituminous Coal (steam)	1,213,000	24.36	39%	0.85	$24.9
Lignite Coal (steam)	1,213,000	24.36	39%	0.87	$28.1
Bituminous Coal IGCC	1,402,000	34.21	41%	0.77	$27.6
Sub-bituminous Coal IGCC	1,402,000	34.21	41%	0.8	$29.9
Lignite IGCC	1,402,000	34.21	41%	0.81	$32.9
Bituminous IGCC w/CCS	2,006,000	40.26	35%	0.09	$46.2
Sub-bituminous IGCC	2,006,000	40.26	35%	0.09	$49.0

[54] Energy Information Administration < http://www.eia.doe.gov/oiaf/aeo/electricity.html>.
[55] Energy Information Administration/Assumptions to the Annual Energy Outlook 2005, <http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf >.
[56] Assumes heat content and emissions characteristics of sub-bituminous coal.

w/CCS					
Lignite IGCC w/CCS	2,006,000	40.26	35%	0.1	$52.5
Conventional Hydro (turbine)	1,451,000	12.35	N/A	0	$29.9
NGCC	567,000	11.04	52%	0.36	$105.9
Nuclear	1,957,000	60.06	N/A	0	$31.9
Distillate Fuel Oil (steam)	395,000	10.72	33%	0.82	$136.1
Solar Photovoltaic	4,467,000	10.34	N/A	0	$185.9
Wind	1,134,000	26.81	N/A	0	$33.9
The costs shown are in 2004 dollars. Overnight costs represent the cost of new projects, initiated in 2004, including a contingency factor of five to seven percent, and a technological optimism and learning factor, which reflects higher costs for first-of-a-kind or emerging technologies. Data on these factors was collected from the EIA's Annual Energy Outlook 2005.[57]					

Summary of technology costs:

- The cheapest sources of carbon-neutral power per megawatt hour at plant gate are, in order, hydroelectric ($29.9/MWh), nuclear ($31.9/MWh), wind ($33.9/MWh), biomass ($55.6/MWh), and photovoltaic ($185.9/MWh).
- Biomass and PV are higher in price than the other carbon-neutral power sources at current costs.
- Hydroelectric, nuclear, and wind, are close enough in price that they are all likely to be cost-competitive under various conditions. This model does not capture the great regional variability that could alter the competitiveness of each in different areas.
- IGCC with capture and sequestration appears to be more expensive than hydroelectric, nuclear, and wind.
- Biomass may be cost-competitive with IGCC with a moderate carbon tax, but will still not be competitive with the other carbon-neutral technologies. It may become cost-competitive if credit for terrestrial sequestration of carbon dioxide is allowed.

VII. Scenarios

To assess the potential for a reduced-carbon power sector, a system dynamics model was developed in conjunction with this study.[58] Scenarios that combined varied levels of different energy technologies to satisfy projected electricity demands in the region were developed and modeled. Costs for implementing these scenarios were computed. General assumptions used in the model, and a summary of each scenario are described in this section.

General assumptions

- Baseline growth in demand is 1.9% average annual growth. At this rate, regional power demand in 2055 is 948 TWh/yr.
- The goal of this exercise is to meet demand while not exceeding 20% of 1990 emissions for the electric power sector. 20% of 1990 emissions is about 47 million metric tonnes of CO2.

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[57] Energy Information Administration, Assumptions to the Annual Energy Outlook 2005.
[58] S. J. Taff. (Department of Applied Economics, University of Minnesota, 2006).

- Demand for peak load power remains 2% of total annual power demand, as it was in 2004. Peak load power consists of a mixture of natural gas and fuel oil-based generation. All natural gas and fuel oil power is assumed to be peak load, and the same mix of these fuels is assumed to continue in 2055.
- Minor sources of power, such as petroleum coke, are not considered in this analysis.
- Transmission is not a constraint. We assume that transmission can be built in 50 years to adjust to these scenarios. Transmission will be required for most of these scenarios.

Technology assumptions:

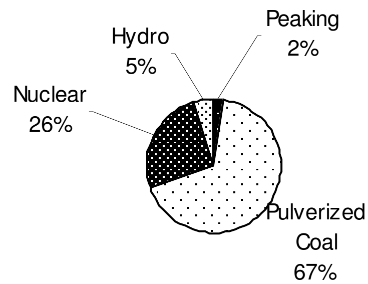
- It is possible to capture and sequester 90% of the carbon dioxide produced in an IGCC plant. Since IGCC with sequestration is not completely carbon neutral, its use is limited by the CO2 cap.
- Peaking power, consisting of fuel oil and natural gas, is the only source of emissions other than coal.
- Wind is constrained as a percentage of total net generation (conservatively 20%, liberally 50%).
- Biomass power is resource-constrained, with a maximum regional resource of 257 TWh per year.
- Hydroelectric power is resource-constrained, with a maximum regional resource of 90 TWh per year.

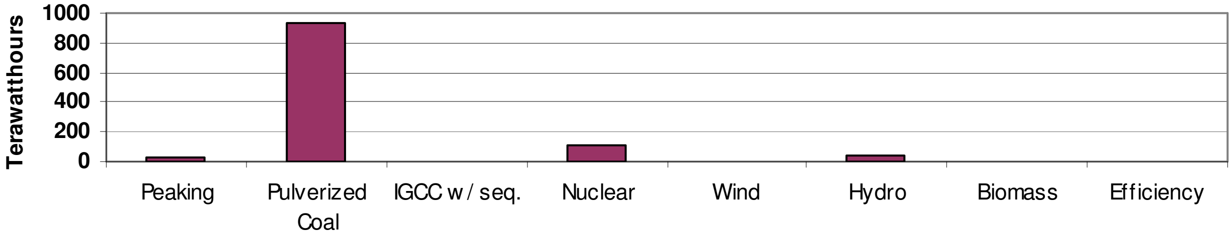
Table 11: Summary of scenarios

	2004		**Low Cost - 2055**		**Low Cost Reduced Carbon - 2055**	
	Million MWH	Thousand MW	Million MWH	Thousand MW	Million MWH	Thousand MW
Peaking	9	27	22	63	22	63
Pulverized Coal	281	43	926	117	22	3
IGCC w/ seq.	0	0	0	0	0	0
Nuclear	107	16	110	13	893	107
Wind	3	1	0	0	77	21
Hydro	19	5	44	10	88	20
Biomass	1	0	0	0	0	0
	High Wind, High Nuclear - 2055		**High Coal - 2055**		**High Renewable - 2055**	
	Million MWH	Thousand MW	Million MWH	Thousand MW	Million MWH	Thousand MW
Peaking	22	63	15	42	9	26
Pulverized Coal	0	0	0	0	0	0
IGCC w/ seq.	0	0	449	85	70	13
Nuclear	551	66	107	13	107	13
Wind	441	123	147	41	232	65
Hydro	77	18	19	5	39	11
Biomass	0	0	7	1	23	3

Lowest Cost (no CO2 reduction)

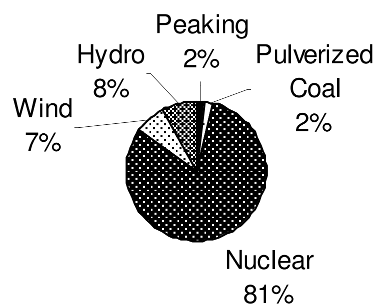
- 1.9% annual growth in demand
- Wind is 7% of net generation
- Hydroelectric is 4% of net generation
- Nuclear is 10% of net generation
- Pulverized coal is 84% of net generation
- No biomass

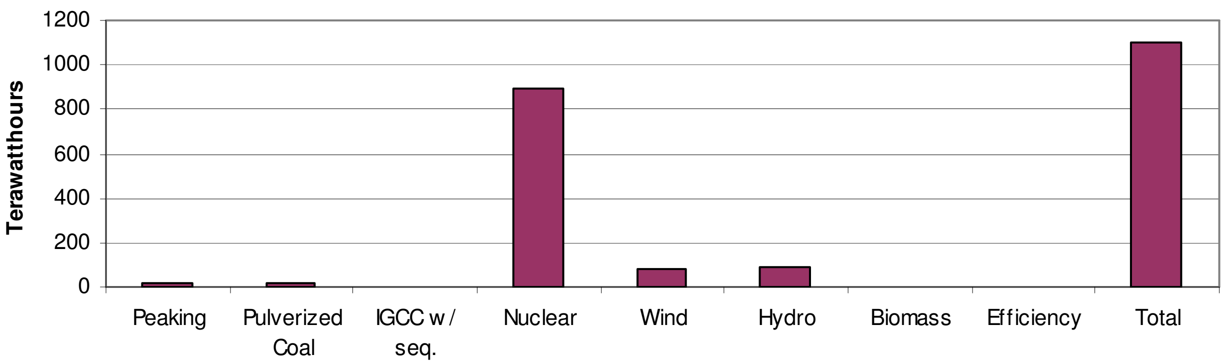




Lowest Cost Reduced Carbon

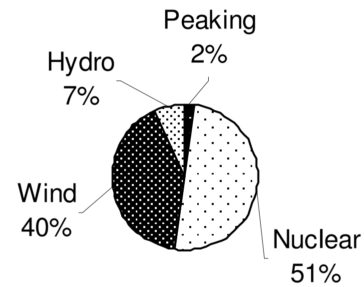
- 1.9% annual growth in demand
- Wind is 7% of net generation
- Hydroelectric is 8% of net generation (4 times current levels)
- Nuclear is 81% of net generation
- Pulverized coal is 2% of net generation
- No biomass

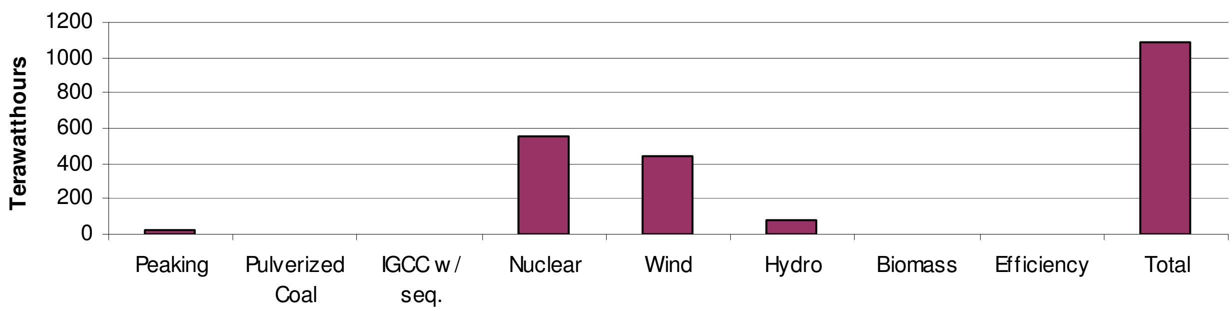




High Wind, Nuclear, and Hydro - 2055

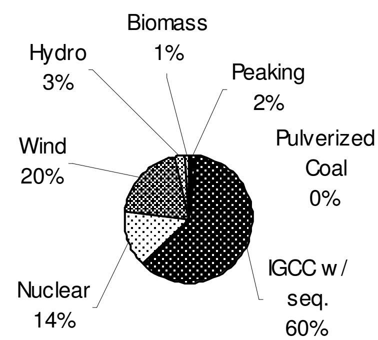
- 1.9% annual growth in demand
- Wind at 40% of net generation
- Hydroelectric is 4 times current levels
- Nuclear is 50% of net generation
- No coal or biomass

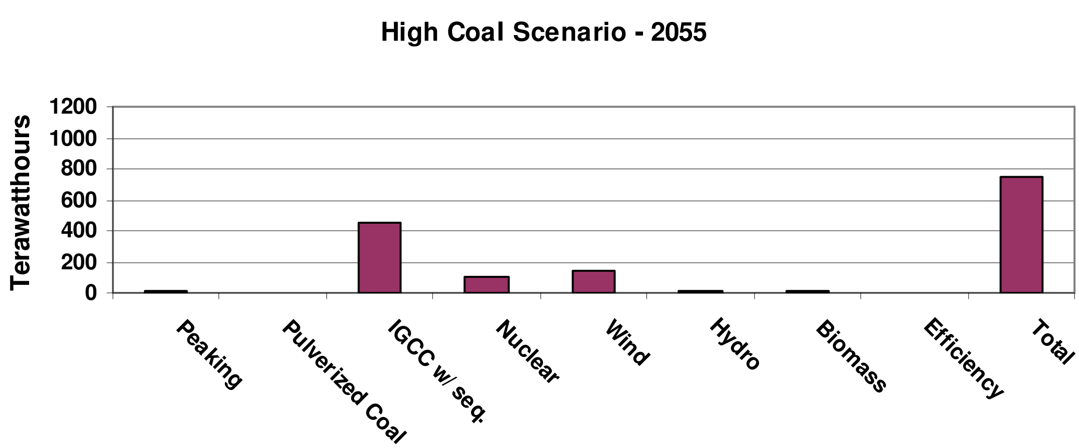




High Coal Scenario - 2055

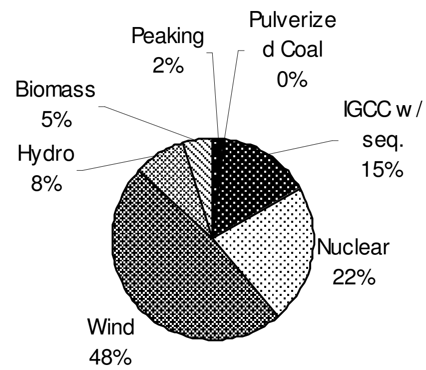
- 1% annual growth in demand
- Maximum allowable IGCC with sequestration, given 90% of CO_2 is sequestered.
- Wind at 20% of net generation
- Biomass at 1% of net generation
- Hydroelectric at current levels
- Nuclear at current levels

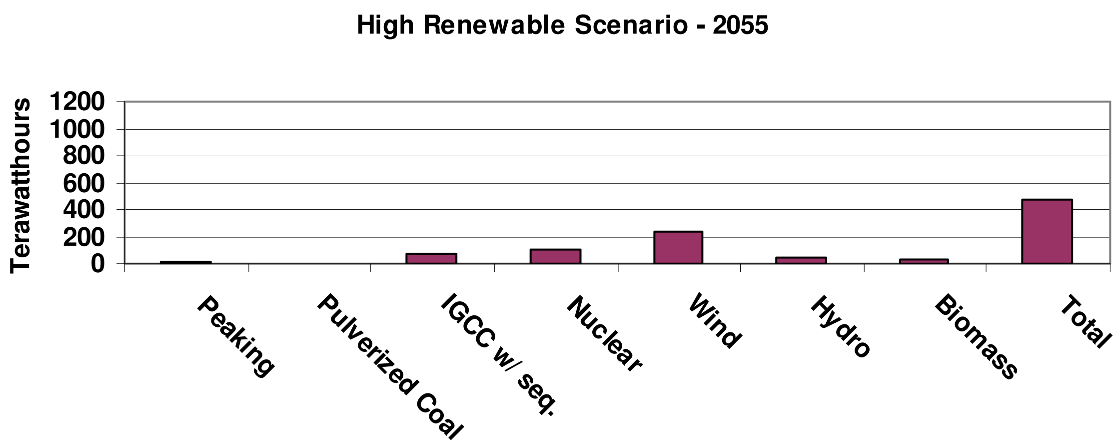




High Renewable Scenario

- Constant demand after 2010
- Coal consumption shifted to IGCC with seq. Net generation is one quarter of 2004 levels.
- Wind is 50% of net generation
- Biomass is 5% of net generation
- Nuclear is held constant
- Hydroelectric net generation is doubled over 2004 levels.





VIII. Recommendations for further study

The results of the study indicate that in order to achieve the emissions target, the electric power generation sector will need to be dramatically transformed. In reaching this conclusion, several areas for future study and analysis were identified. Analysis of these topics will help further refine recommendations for transforming the energy system of the upper Midwest region. These recommendations include:

- Incorporate a geographic information system (GIS) component to the study to demonstrate the link between energy resources, population centers, rail and pipeline infrastructure and transmission systems.
- Relate the recommendations for power production with transmission location and capacity.
- Include other greenhouse gas emissions associated with current and recommended technologies into the analysis.
- Evaluate the cost and impact of demand reduction strategies.
- Compare the risks associated with carbon dioxide emissions (climate change), carbon dioxide sequestration (leaks and marine ecosystem damage) and nuclear waste storage.
- Explore the economics of storing wind power, i.e. compressed air storage.
- Analyze the integration of wind power with other power production technologies, i.e. pairing wind with hydroelectric or natural gas)
- Study the economics of a bio-refinery model that produces electricity as a side-product.
- Thoroughly evaluate regional potential for terrestrial sequestration and evaluate its impact on the economics of producing biomass.
- Study the integration of the electric power sector with liquid fuels production to understand the benefits and trade-offs of producing liquid fuels from coal and biomass gasification, and hydrogen production.
- Extend the analysis to all 50 states.