Staff Paper P06-10 November 2006

# Staff Paper Series

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**DEPARTMENT OF APPLIED ECONOMICS**
**COLLEGE OF FOOD, AGRICULTURAL AND NATURAL RESOURCE SCIENCES**
**UNIVERSITY OF MINNESOTA**

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*Kathryn A. Jones: Minnesota Environmental Initiative. Brendan Jordan: Great Plains Institute. Kenneth H. Keller: Center for Science, Technology, and Public Policy, University of Minnesota. Steven J. Taff: Department of Applied Economics, University of Minnesota.*



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## Abstract

We develop scenarios for reducing carbon dioxide emissions from the electricity sector in the upper Midwest (Wisconsin, Illinois, Minnesota, Iowa, North Dakota, South Dakota, Montana, Wyoming, and Manitoba) by 80% relative to 1990 levels. The report has three major components: 1) an inventory of CO2 emissions from all fossil fuel combustion in the region from 1960-2001, subdividing by economic sector and specific electricity generating station; 2) an evaluation of all electricity resources in the region and all technologies for utilizing them, taking into account the overall scale of the resource, technology costs, and other issues that influence the selection of a certain technology; and 3) the development of a simulation model to examine the impact of various factors (policies, prices, technologies, resources) on the regional electricity supply and its emissions from 2005-2055.

**Acknowledgements**

The study was developed in collaboration with the following organizations:
- Center for Science, Technology and Public Policy, University of Minnesota
- Initiative for Renewable Energy and the Environment (IREE), University of Minnesota
- Legislators' Forum
- Minnesota State Extension Service
- Powering the Plains (PTP) initiative of the Great Plains Institute (GPI)

Funding came from the following:
- Garfield Foundation
- Initiative for Renewable Energy and the Environment (IREE)

In-kind support came from the following:
- Center for Science, Technology and Public Policy, University of Minnesota
- Energy Center of Wisconsin
- Fresh Energy (formerly Minnesotans for an Energy Efficient Economy)
- Great Plains Institute
- Izaak Walton League
- Minnesota State Extension Service

The members of the Powering the Plains working group assisted in planning the project and providing early guidance on methodology and goals. Powering the Plains (PTP) encompasses the Dakotas, Iowa, Minnesota, Manitoba and Wisconsin and brings together top elected and government officials, utility industry executives, agricultural producers and farm organization representatives, and renewable energy advocates. The working group endorsed the need for a research project developing scenarios for an 80% reduction in $CO_2$ emissions and provided the initial impetus for this project. Members of PTP have reviewed drafts and monitored the progress of the research, reviewing successive drafts. Current membership in PTP includes the following people and institutions, all of whom were instrumental in improving this research.

- Jim Burg, Former SD Utilities Commissioner, Wessington Springs, SD.
- Kim Christianson, Energy Program Manager, North Dakota Department of Commerce Bismarck, ND.
- Gary Connett, Manager, Manager of Resource Planning and Member Services, Great River Energy Elk River, MN.
- Larry Diedrich, Farmer and former South Dakota State Senator, Elkton, SD
- Mike Eggl, Vice President, Government Affairs, Basin Electricity Co-op Bismarck, ND.
- Bill Grant, Midwest Director, Izaak Walton League of America St. Paul, MN.
- Christine Hamilton, Owner and Manager, Christiansen Land and Cattle Kimball, SD.
- William Hamlin, Manager, Emissions and Credit Trading, Manitoba Hydro Winnipeg, MB.
- Dave Miller, Director, Commodity Services, Iowa Farm Bureau Des Moines, IA.
- Jon Nelson, Farmer and Chair, Natural Resources Committee, North Dakota House of Representatives, Wolford, ND.
- Michael Noble, Executive Director, Fresh Energy (formerly Minnesotans for an Energy-Efficient Economy) St. Paul, MN.
- Rolf Nordstrom, Director, Upper Midwest Hydrogen Initiative Minneapolis, MN.
- Lola Schoenrich, Senior Program Director The Minnesota Project Saint Paul, MN.
- John Sellers Jr., Farmer and former Field Coordinator, Chariton Valley Biomass Project Corydon, IA.

- Kurt Simonsen, Manager, Utilities and Energy Issues, Manitoba Energy Development Initiative Winnipeg, MB.
- Beth Soholt, Director, Wind on the Wires Project St.Paul, MN.
- Patrick Spears, President, Intertribal Council on Utility Policy Ft. Pierre, SD.
- Michelle Swanson, Manager for Policy Development, Xcel Energy Minneapolis, MN.
- Paul Symens, Farmer/Feedlot Owner, Board Member, Farmers Union, Manufacturing and Processing Association, and former State Senator Amherst, SD.
- Ed Woolsey, Consultant, Union of Concerned Scientists and Iowa RENEW Prole, IA.

The Legislators Forum is a regional and bipartisan gathering of 32 legislative leaders from all parties, eight each from MB, MN, ND and SD (2004 and 2005). At the 2005 gathering, the Forum passed a resolution calling for a long-term energy transition in the region that "relies on clean energy production and sequestration of the carbon dioxide", and endorsing this research project, although not endorsing the goal of an 80% reduction in $CO_2$ emissions. Powering the Plains and the University of Minnesota research team have presented initial results of the scenario research at the 2005 and 2006 meetings of the Forum.

Many people outside of PTP offered advice, provided technical assistance, answered questions, and reviewed drafts. They include:

- Dean Abrahamson, Humphrey Institute of Public Affairs
- Keith Butcher, Center for Energy and the Environment
- Peter Ciborowski, Minnesota Pollution Control Agency
- Jeffrey Greenblatt, National Environmental Trust
- Eric Larsen, Princeton University
- Matt Scheurger, consultant
- Robert Socolow, Princeton University
- Kurt Walzer, Ohio Environmental Council
- Robert Williams, Princeton University
- Elizabeth Wilson, Humphrey Institute of Public Affairs

**Executive Summary**

In this study we develop scenarios for reducing carbon dioxide emissions from the electricity sector in the upper Midwest (Wisconsin, Illinois, Minnesota, Iowa, North Dakota, South Dakota, Montana, Wyoming, and Manitoba) by 80% relative to 1990 levels. It has three major components: 1) an inventory of $CO_2$ emissions from all fossil fuel combustion (coal, natural gas, and petroleum) in the region from 1960-2001, subdividing by economic sector and specific electricity generating station; 2) An evaluation of all electricity resources in the region and all technologies for utilizing them, taking into account the overall scale of the resource, technology costs, and other issues that influence the selection of a certain technology; and 3) the development of a simulation model for examining the impact of various policies, prices, technologies, resources on the regional electricity supply and its emissions from 2005-2055.

An inventory of $CO_2$ emissions from natural gas, coal, and petroleum consumption in the region shows that the major sources of emissions are coal consumption in the electric sector and petroleum consumption in the transportation sector.

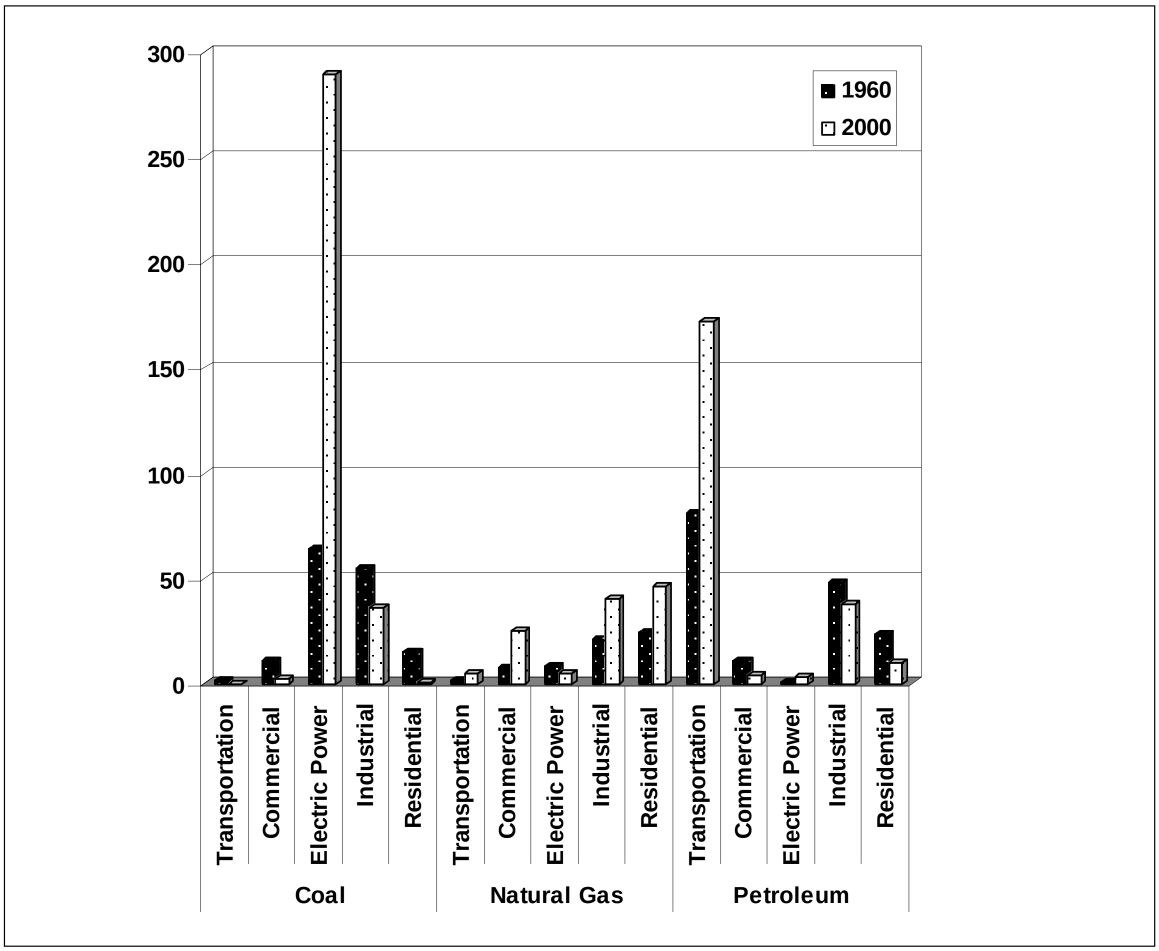


**Figure 1: $CO_2$ Emissions by Sector and Fuel Type, 1960 and 2000**
**Source: Authors' analysis using data from EIA-906/920 and EIA-860.**

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) | $CO_2$ Emissions (tons/MWh) | Average Price of Electricity[2] ($/MWh) |
|---|---|---|---|---|
| Wind | 607.920 MWa[3] | $1,091,000 | 0 | 51.7 |
| Conventional Hydro | 20,000 MW[4] | $1,320,000 | 0 | 30.0 |
| Municipal Solid Waste/ Landfill Gas | Uncertain | $1,443,000 | 0 | 48.0 |
| Biomass | 77,000 MW | $1,659,000 | 0 | 68.6 |
| Nuclear | Unconstrained | $1,744,000 | 0 | 48.9 |
| Photovoltaic | Uncertain | $3,981,000 | 0 | 268.6 |
| Coal (IGCC w/CCS) | Uncertain | $1,873,000 | 0.1 | 56.9 |
| Natural Gas – Advanced Gas Turbine | Uncertain | $367,000 | 0.39 | 44.3 |
| Coal (IGCC) | Unconstrained | $1,1349,000 | .88 | 43.0 |
| Distillate Fuel Oil – Advanced Combustion Turbine | Uncertain | $367,000 | 0.59 | 111.5 |
| Old Coal (steam) | Unconstrained | $0 | 1.14 | 19.9 |
| New Coal (steam) | Unconstrained | $1,167,000 | .94 | 40.2 |

A simulation model was developed using data from the regional electric system analysis. The model contains default data for energy prices, regional demand and demand growth, technology costs, and various policies. The model also allows users to change most basic parameters to explore the implications of their own assumptions on the electricity system. The model predicts electricity cost, technology mix, and $CO_2$ emissions over a 50 year period based on policies, costs, and demand assumptions. The scenario model is a flexible, transparent, real-time modeling

[1] Installed costs obtained from US. Energy Information Administration, Annual Energy Outlook 2006
[2] 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).
[3] MWa: Megawatt average. Represents an average capacity that accounts for the variability of wind in each wind class. Availability is assumed at 33.3%.
[4] Includes existing capacity as well as undeveloped capacity according to Idaho National Laboratory and Manitoba Hydro.

tool that can be used by any Midwestern group seeking to understand the options available to them, and the implications of their assumptions as they begin to chart a path to a reduced carbon energy economy. A web-based demonstration is available at **http://broadcast.forio.com/pro/co2tracker** **.**

The authors used the model to generate a variety of scenarios, each presenting a different mix of end-use efficiency, policies, and power generation technologies that would meet electricity demand, and carbon dioxide emission constraints. Despite variations in technologies, costs, as represented by the average cost of electricity, differed by 10 to 20 percent. The various scenarios are summarized in pages 43-60.

Achieving the magnitude of carbon dioxide emission reductions tested in this study requires a rapid 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.

Scenarios presented in this report suggest that the study goal of an 80% reduction over 1990 levels by 2055 is possible given current technology. Furthermore, the study suggests that there are a variety of ways to meet that goal while increasing average electricity costs by 15-30% over a Business as Usual scenario. The study suggests that the cheapest way to reduce emissions is by reducing demand, and that demand reduction combined with emissions reduction through technological change can actually result in lower cumulative system-wide costs for electricity due to cost reductions from reducing demand.

**Conclusions from the Scenario Analysis:**

- Implementation of a CO2 policy (standard or tax) as late as 2015 can still result in meeting the project goal by 2055, *assuming very little pulverized coal capacity comes on line before that date.* Because many pulverized coal plants are being planned right now, policy intervention will likely be required before 2015, at the very least to allow utilities to avoid sunk costs in planning plants. The sooner the policy is implemented, the sooner the goal is met. This research gives clear direction regarding the magnitude of a standard or tax and what impact it will have.
- Only the scenarios that imposed explicit CO2 policies met the study goal.
- Because pulverized coal plants are the cheapest technology with a significant resource (hydro is cheaper but resource constrained) it always becomes the dominant technology unless specific policies eliminate it. Very little pulverized coal electricity can exist while meeting the study goals.
- Old pulverized coal is the cheapest technology, because for the most part the capital expenditure in these plants is paid for. In all scenarios these plants are forced to retire at the end of their lives, but this may not occur in reality. These plants may continue on long after the 50 year timeframe states as an assumption of this study. The region will need to develop policies to assure that these plants eventually shut down, although they would not need to do so immediately in order to meet a 2055 goal. Keeping them running as long as possible may

be a strategy for preventing the construction of new pulverized coal plants while other resources are being developed.

- Even with aggressive development of renewable energy, there will still be a need for a considerable amount of non-renewable base load electricity. The most likely candidates at present are nuclear and coal IGCC with capture and storage of CO2. Both of these options may have challenges from the perspective of social acceptance, but dealing with the CO2 problem as outlined in this report likely means coming to terms with one or both of these options.
- Wind is likely to be the dominant source of renewable energy due to economics and resource potential. Hydroelectric is resource constrained, but will expand as much as possible due to its favorable economics. Biomass is unlikely to be a significant source of electricity because of its unfavorable economics relative to wind and hydroelectric, unless it is favored by policy. The economics of biomass power may be improved by polygeneration of heat, fuels, and electricity, but that is not considered in this model.
- Demand reduction is the cheapest way to reduce CO2 emissions, although it has the seemingly unintuitive effect of increasing the average cost of electricity. This is because the utility spends some portion of its revenue on reducing demand, and this cost is spread among fewer units of power that are still produced. Although this increases the average cost of electricity, it decreases overall cumulative spending on electricity.
- Demand reduction in combination with policy intervention can result in cumulative costs that are actually cheaper than the Business as Usual scenario. This suggests that aggressive demand reduction could actually be used to pay for climate change mitigation.

## 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 economic, technological and policy drivers, for reducing carbon emissions in the electricity sector in the upper Midwest region (Illinois, Iowa, Minnesota, Montana, North Dakota, South Dakota, Wisconsin, Wyoming, and the Province of Manitoba).

The study region includes 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 region creates interesting analytical opportunities due to its heterogeneity – containing the nation's largest reserves of coal as well as large resources for geologic sequestration of carbon, its largest wind resource, large undeveloped hydroelectric potential, a large biomass resource, and other resources, as well as varying demand profiles.

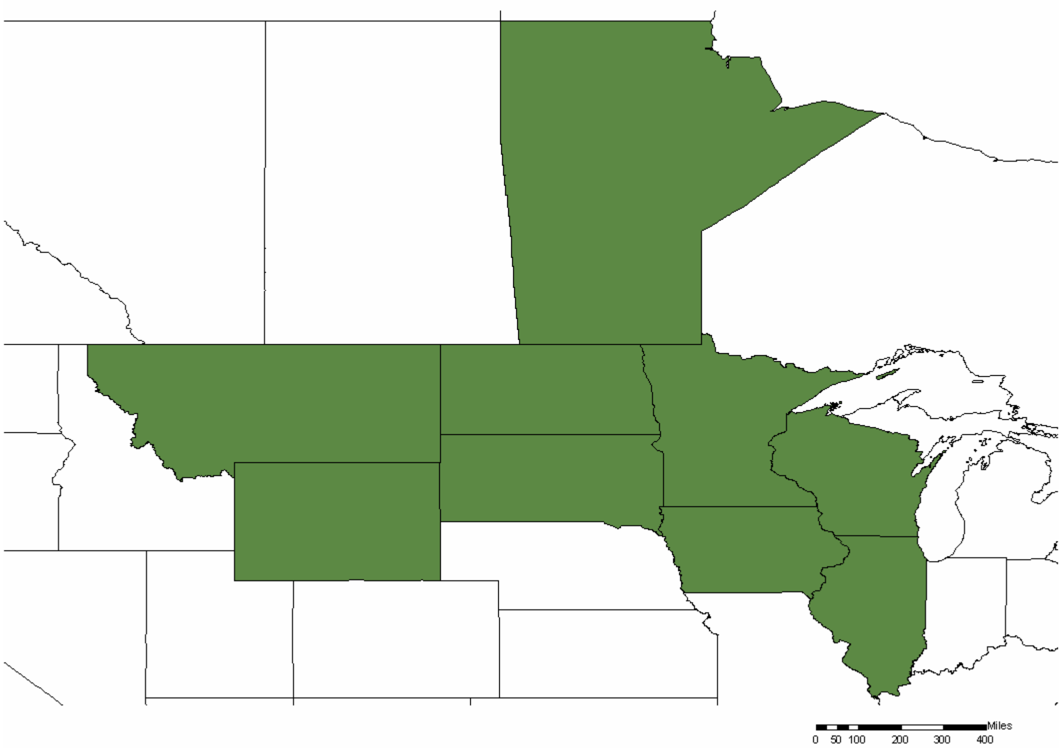


**Figure 2: The study region, including Illinois, Iowa, Minnesota, Montana, North Dakota, South Dakota, Wisconsin, and the Province of Manitoba.**

For the purpose of this analysis, the goal was to reduce carbon dioxide emissions from electricity production in the region to 20 percent of 1990 levels (or reducing emission by 80% of 1990 levels) by 2055 while meeting projected electricity demands.

The goal of reducing $CO_2$ emissions by 80% percent relative to1990 levels was chosen because this is the higher end of a range (50-80%) presented by the Intergovernmental Panel on Climate Change (IPCC) for how much reduction in $CO_2$ emissions worldwide will result in stabilization of atmospheric carbon dioxide concentrations, according to the First Assessment Report.[5] Global stabilization 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 reductions of other greenhouse gases that aren't considered in this study. For these and other reasons, it is not possible to relate emissions reductions in the study region to global stabilization of greenhouse gases at any level.

The study was limited to emissions of carbon dioxide from the combustion of fossil fuels in the electricity sector, which account for the majority of greenhouse gas emissions, both in this region and worldwide. Future iterations of this study could include the other major greenhouse gases. $CO_2$ is the most important greenhouse gas, and reducing emissions of $CO_2$ will have the greatest impact on climate change. It was for this reason, combined with limited resources that this study focused only on $CO_2$.

While Pacala et al. (2004)[6] took 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 in a different direction 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 electricity infrastructure.

The study was conducted in three 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. We completed an inventory of $CO_2$ emissions from fossil fuel combustion for all economic sectors. We also evaluated 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 developed a simulation model for use in conjunction with this analysis. The model integrated the technology, resource, and cost assumptions developed in this analysis that would allow users to evaluate the effects of technological, economic, and policy changes on the electricity sector over the next 50 years. Finally, the teams worked together to populate the model and use it develop scenarios for different electricity production futures that met the proposed $CO_2$ emission reduction goals based on policies and mandates.

[5] Intergovernmental Panel on Climate Change. 1990 First Assessment Report.
[6] Pacala, S., R. Socolow. Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Existing Technologies. Science Vol. 305. no. 5686, pp. 968 - 972

Although the inventory exercise considers all economic sectors, the model and scenarios deal only with the electricity sector because this is the largest source of emissions.

A transformation of this scale required a detailed analysis of the existing electricity supply for the region, an evaluation of resource availability, and an assessment of current and potential electricity 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 long-term planning horizon will allow time for adoption and implementation of policies and technologies that would enable the targeted carbon dioxide emission reductions.

Specifically, the study includes evaluation of the following options for the region to achieve this goal:

- Further development of renewable electricity in the region, including wind, biomass and hydroelectricity.
- Implementation of carbon capture and sequestration for coal-based power generation.
- Reduction of existing coal based electricity generation.
- Reduction of overall demand.

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.
- Current demand and demand growth in the region.
- Current fuel costs.
- Current policies influencing electricity production and consumption within the region.

Scenarios explored the following:

- Impact of various policies on the relative economics, and adoption, of various energy technologies – including taxes, subsidies, standards, and mandates.
- The average and cumulative cost of electricity under various scenarios.
- Various energy resource mixes that allow the region to meet demand while dramatically reducing CO2 emission.

## 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)[7] 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[8] 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.

[7] EIA-906/920 and EIA-860, 2004 data
[8] See Appendix I for detailed assumptions.

Figure 3 shows emissions for the eight 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 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. Although this methodological decision may draw readers to the conclusion that the electricity 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.

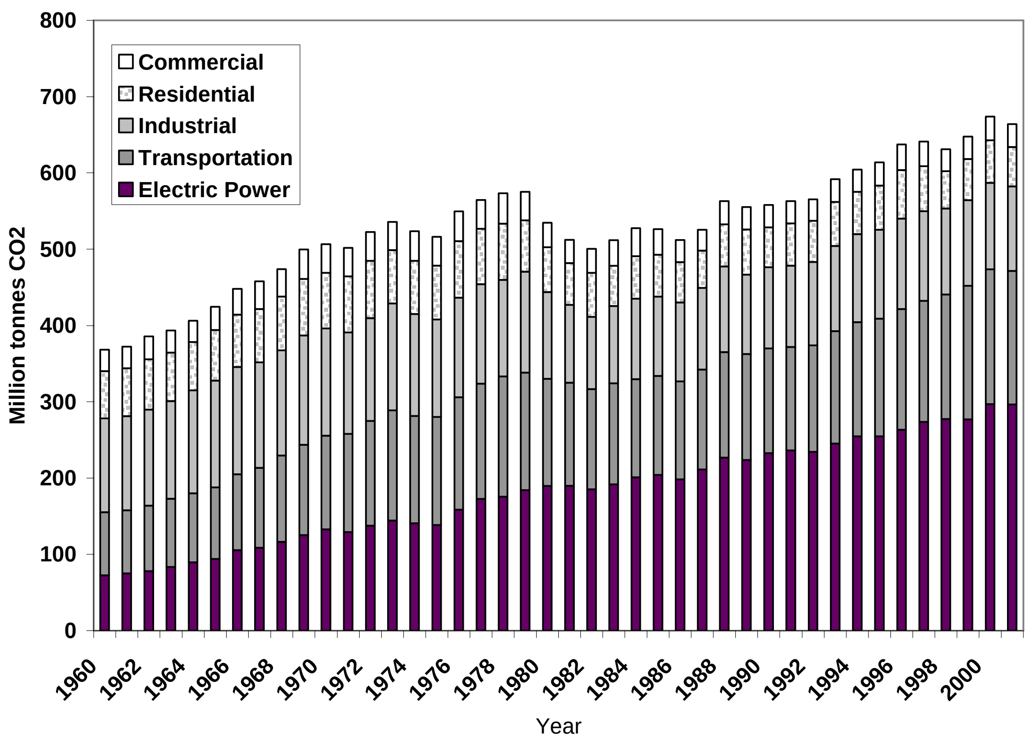


**Figure 3: Total $CO_2$ Emissions from the Region (excluding Manitoba), 1960-2001**
**Carbon dioxide emissions in 1990 were approximately 558 million metric tons. When data from Manitoba for 1990 are included, the total regional carbon dioxide emissions in 1990 are estimated at 604 million metric tons. 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 electricity sector. Source: EIA-906/920 and EIA-860.**

Figure 4 shows carbon dioxide emissions broken down according to fuel type for 1960 to 2001.

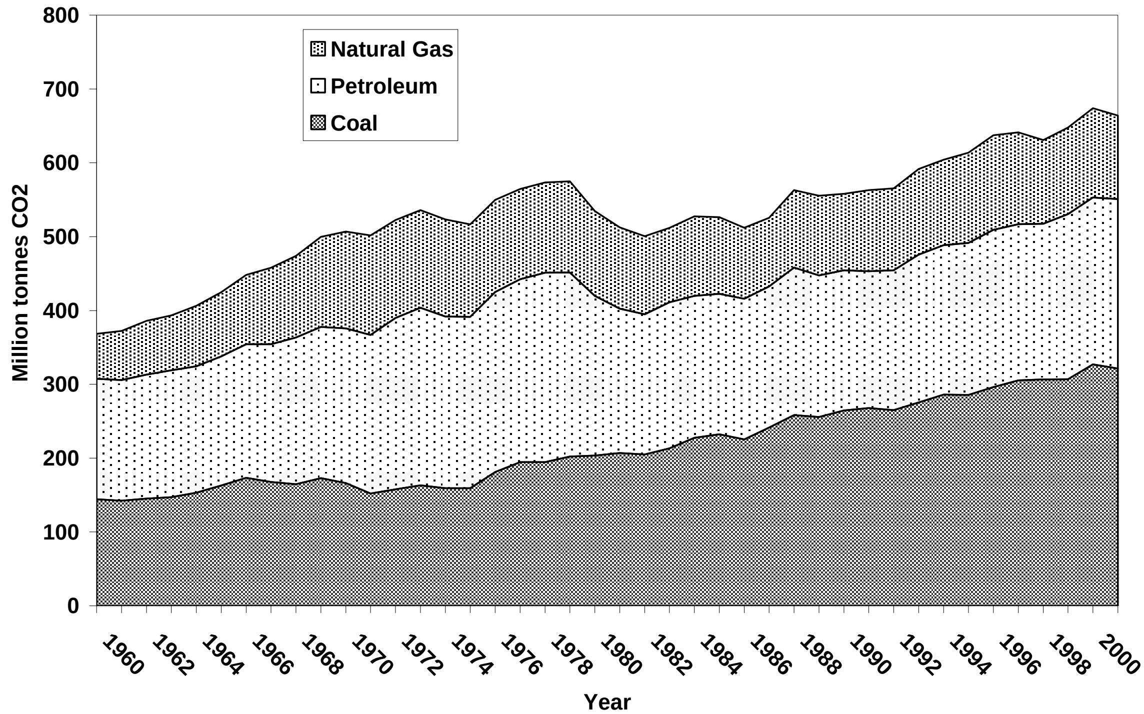


**Figure 4: $CO_2$ Emissions by Fuel Type, 1960-2001**
**This data correlates with the emissions-by-sector trends, as most coal use was in the high-growth electricity sector, and most petroleum use is in the high-growth transportation sector.**
**Source: EIA-906/920 and EIA-860.**

Total carbon dioxide emissions were broken down by sector and by fuel for both 1960 and 2000 in Figure 5 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 electricity sector, and petroleum use in the transportation sector.

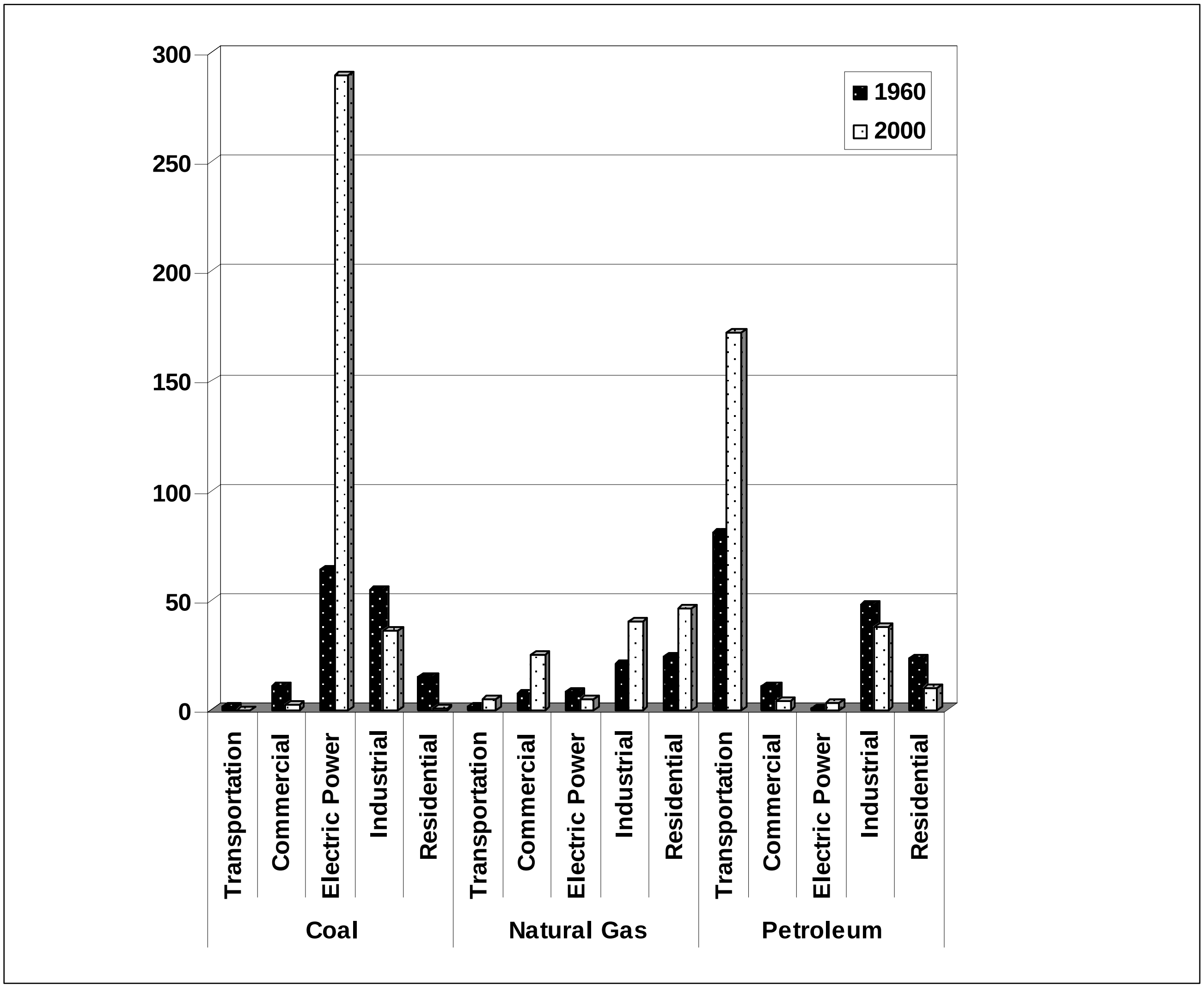


**Figure 5: $CO_2$ Emissions by Sector and Fuel Type, 1960 and 2000**
**Source: Authors' analysis using data from EIA-906/920 and EIA-860.**

Figure 6 shows total emissions by state from 1960 to 2001.

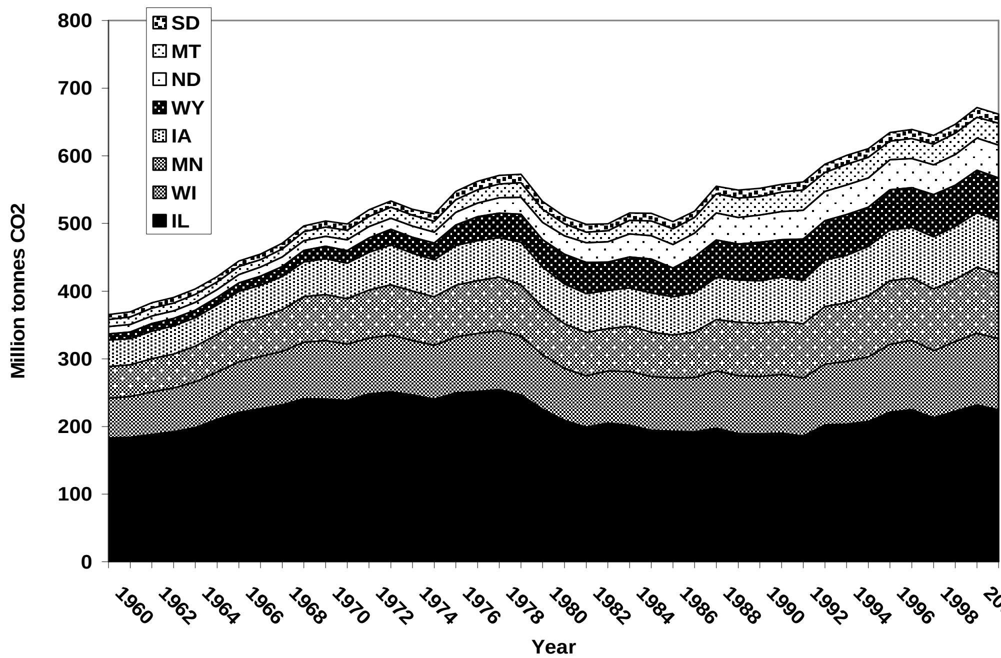


**Figure 6: $CO_2$ Emissions by State, 1960 – 2001**
**Proportions of emissions among the states have remained relatively constant over the past four decades. Emissions in all states declined in the early 1980's likely due to high fuel prices and contraction of the U.S. economy.**
**Source: Fuel use data from EIA-906/920 and EIA-860. Emissions were calculated using methodology developed for the EPA's State Emissions Inventory Tool.**

Figure 7 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 expressed relative to gross state product (GSP) or population. Wyoming performs the worst of all states/provinces relative to GSP or population. Manitoba performs the best in all categories, primarily because its electricity system is dominated by large-scale hydroelectricity, which is carbon-neutral.[9]

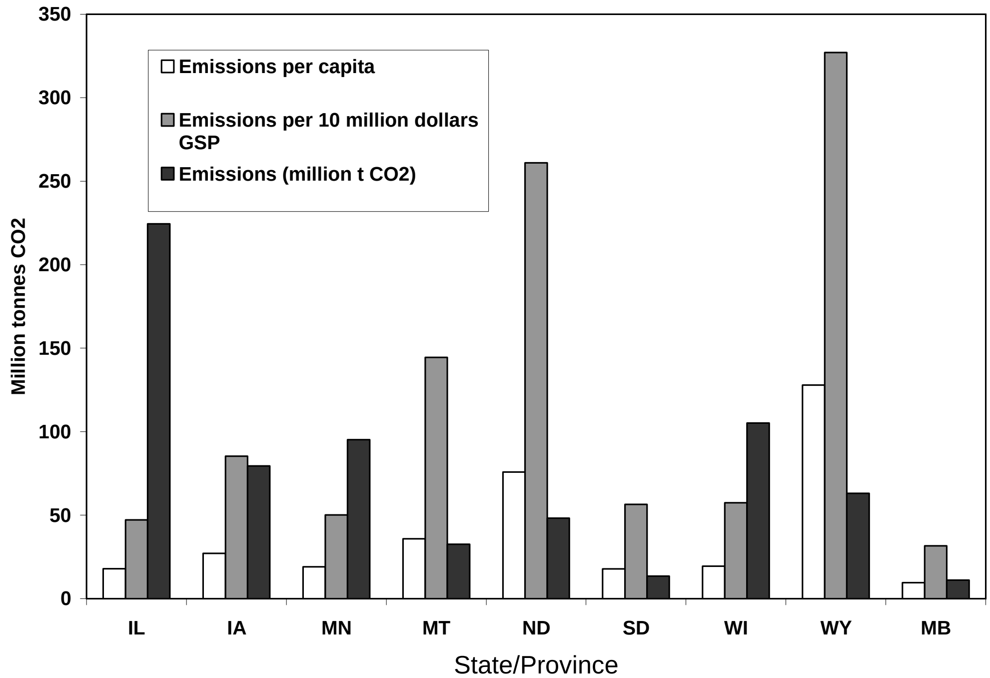


**Figure 7: Total Emissions, Emissions per Capita, Emissions per Gross State Product. Emissions based on 2001 data.**
**Source: Emissions calculated using data from EIA-906/920 and EIA-860 and the methodology developed for the EPA's State Emissions Inventory Tool.**

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.

## Electricity Sector Profile

Fuel sources used to generate electricity in the region are profiled in Figure 8. Table 2 provides a more detailed look at net generation from different energy sources. In the table, fuel types are divided into carbon-emitting and carbon-neutral according to the US Energy Information Administration (EIA) and Environmental Protection Agency (EPA) classification systems.

[9] This study does not consider indirect sources such as methane emissions from reservoirs or emissions from construction of hydroelectric dams.

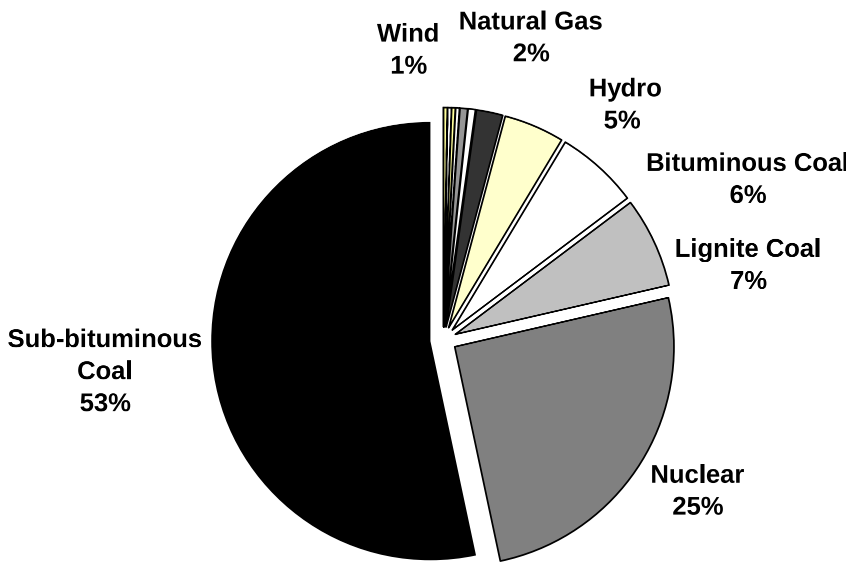


**Figure 8: Regional Electricity Profile**
**The values represent the percentage of total electricity by fuel in the region in 2004**
**Sources: Compiled from EIA-906/920 and EIA-860, Manitoba Hydro (www.hydro.mb.ca), U.S. Nuclear Regulatory Commission website (www.nrc.gov)**

**Table 2: Net Generation by Fuel Type, 2004**

| Fuel Type | Total Number of Facilities in Region | Net Generation (GWh) |
|---|---|---|
| **Carbon-emitting Sources** | | |
| 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 |
| 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 Sources** | | |
| Nuclear | 18 | 107,332 |
| Conventional Hydro | 52 | 50,536 |
| Wind | 29 | 3,245 |
| Landfill gas | 9 | 870 |
| Municipal Solid Waste | 7 | 754 |
| 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 electricity 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.

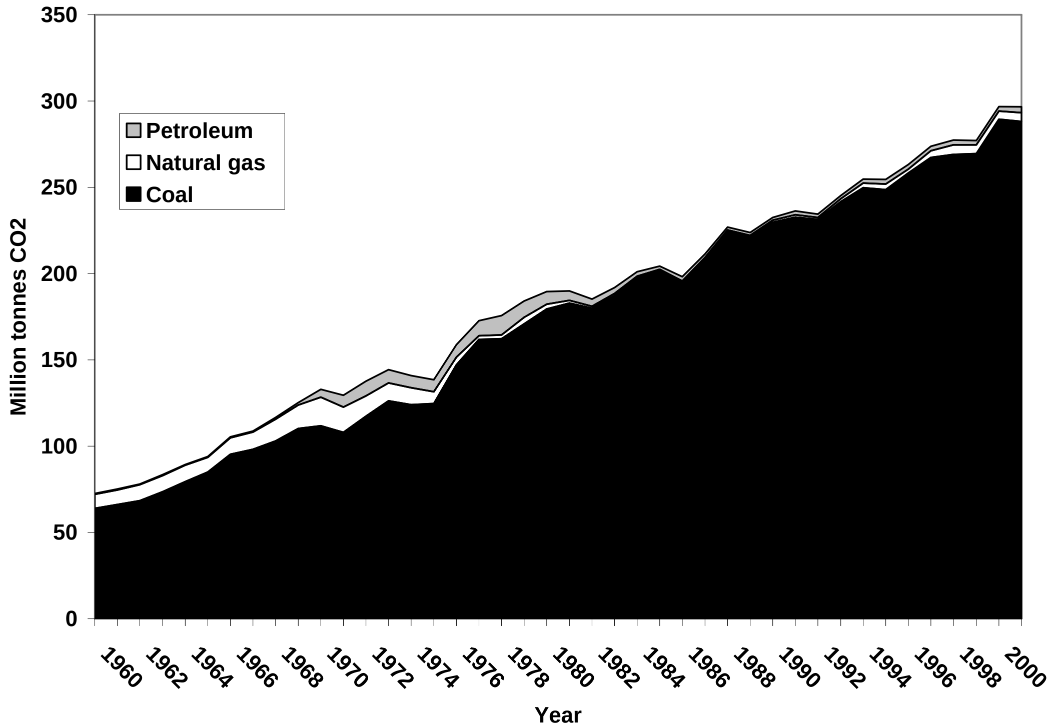


**Figure 9: Electricity Sector Emissions, 1960 – 2001**
**Source: Fuel use data from EIA-906/920 and EIA-860. Emissions were calculated using methodology developed for the EPA's State Emissions Inventory Tool.**

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 electricity 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.

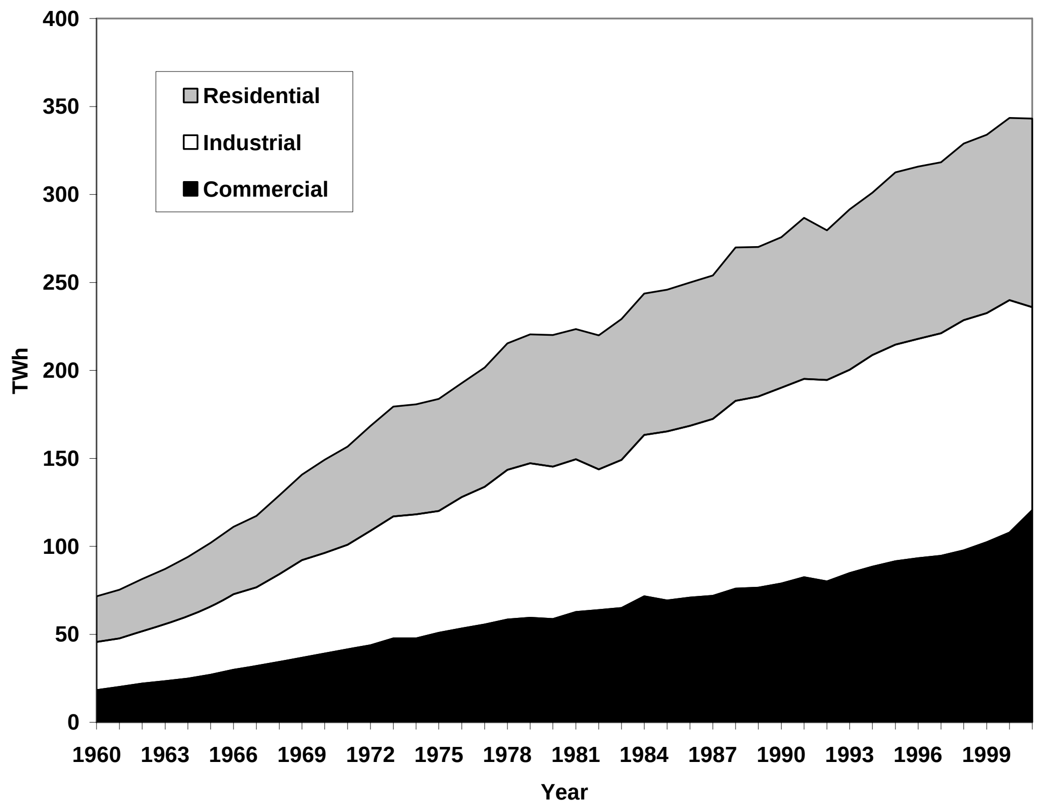


**Figure 10: Electricity Demand by Sector, 1960 – 2001 (excluding Manitoba)**

Electricity is a highly scale-dependant industry. Figure 11a 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, 24% in 10 stations, and 50% in 28 stations. Carbon dioxide emissions are similarly concentrated in a few large facilities.

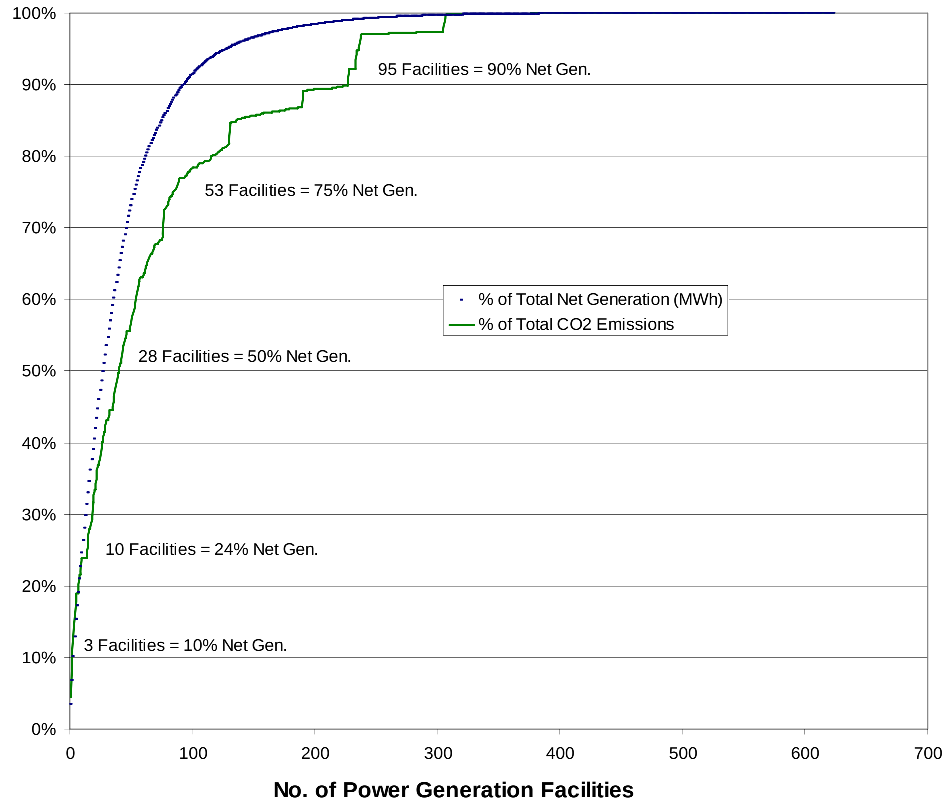


**Figure 11a: Concentration of Electricity Production and $CO_2$ Emissions.**
**Shows total percentage of net generation and emissions in the region by facility in 2004. Three power stations generate over 10 percent of the region's electricity. Twenty-four percent of regional net generation occurs in 10 stations, 50 percent in 20 stations, and 90 percent in 95 stations. Similar trends hold for emissions.**
Sources: Compiled from EIA-906/920 and EIA-860, Manitoba Hydro (www.hydro.mb.ca), U.S. Nuclear Regulatory Commission website (www.nrc.gov)

The region is a net exporter of power. Figure 11b shows net generation and sales of electricity to final consumers from 1990- 2003 for the entire region excluding Manitoba. The region produces far more power than it consumes. Although the region is a net exporter (even after accounting for line losses), the model considers only electricity production necessary to meet demand. This is explained in more detail in Appendix I.

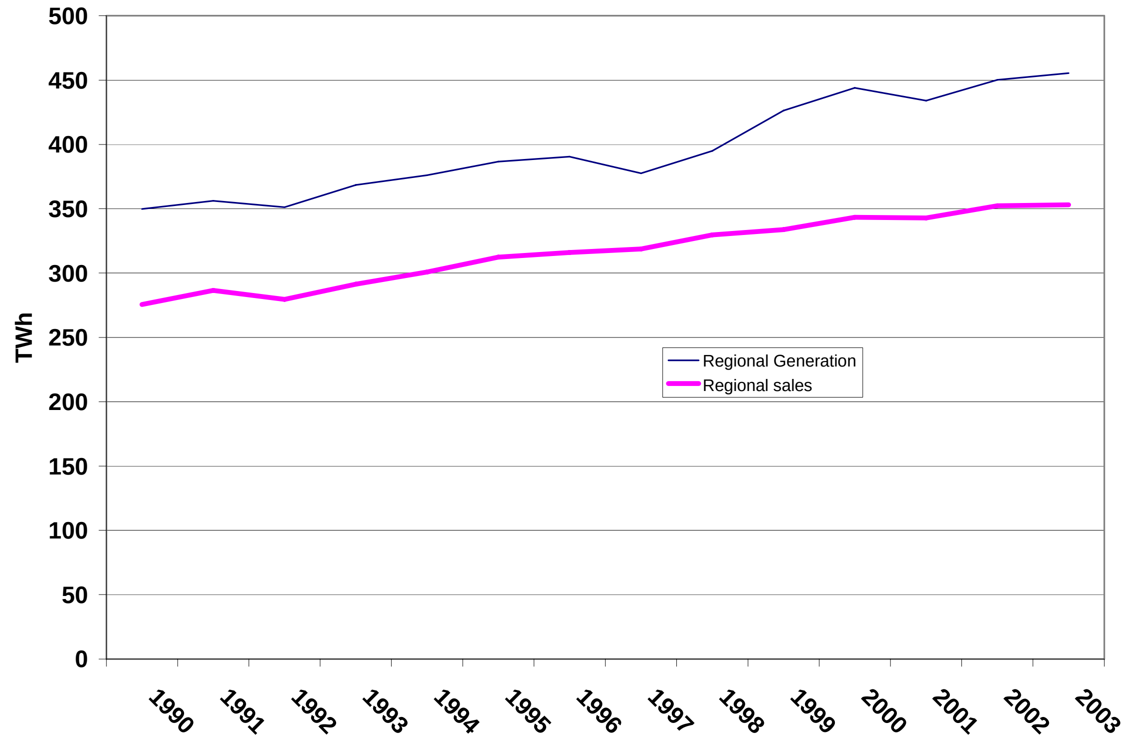


**Figure 11b: Regional Electricity Production and Consumption.**
**The region produces about 25% more electricity than it consumes, meaning that the region is currently a net exporter of electricity after accounting for line and other losses.**
**Sources: Compiled from EIA-906/920 and EIA-860, Manitoba Hydro (www.hydro.mb.ca), U.S. Nuclear Regulatory Commission website (www.nrc.gov)**

Electricity demand in the region is currently met by over 600 stations. As they reach the end of their physical (or economic) lives, their generation capacity will need to be replaced by new or upgraded facilities, and additional capacity will be needed to meet growing demand.

Figure 12 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 electricity production capacity in the region, and shows the capacity deficit that will need to be met by new or re-powered facilities.

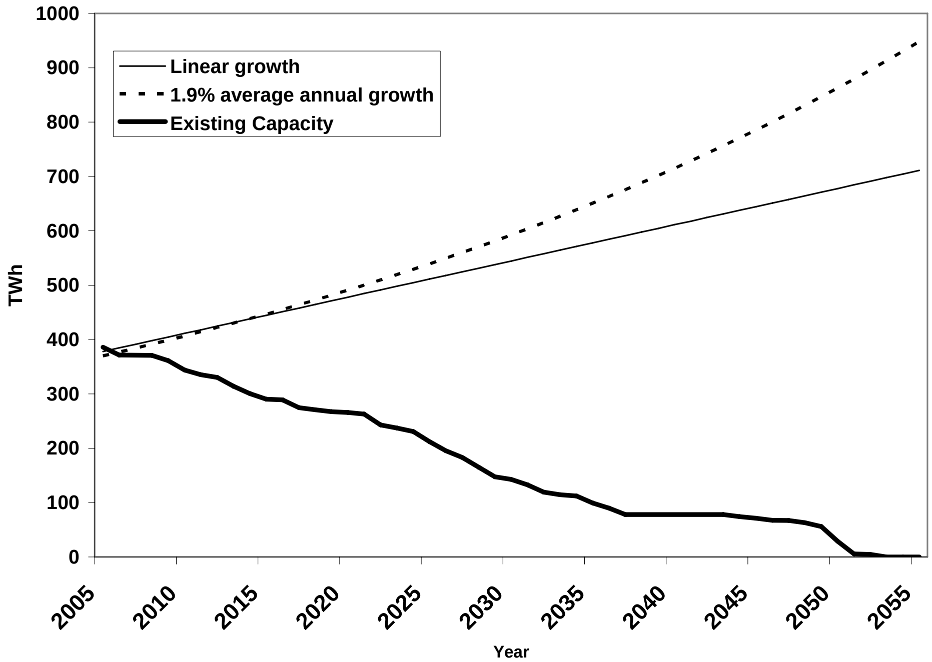


**Figure 12: Electricity Demand and Projected Retirements, 2005 - 2055**
**Generation in TWh applies an average capacity factor of 50% to the total nameplate capacity of all facilities in the region. The average capacity factor was based on reported operating data for each power generation unit in the region for 2004.**[1]

## Effect of Demand-Side Management on Demand Projections

Demand-side management can have a significant impact on projected demand. Various studies suggest that considerable reduction in demand is possible at below the cost of electricity.

The Interlaboratory Working Group Study (also known as the Five Lab Study), was a collaborative effort between 5 U.S. government laboratories to determine the potential of investments in available energy efficiency technologies to reduce growth in demand and reduce greenhouse gas emissions. They concluded that energy demand could be flattened between 1997 and 2010, and that all investments to reach that goal would be cost-effective given a $50/ton carbon tax.

Although the 5 Lab Study is on a national scale, we adapted their analysis to the Midwest by assuming that the same percentage of total electricity consumption could be avoided using similar methods in the Midwest. We also assume that by starting now, instead of in 1997, the same level of efficiency can be achieved at the same cost. Although the 5 Lab Study assumes that only 65% of the possible benefit is achieved in 13 years (because certain appliances have a lifetime of longer than 13 years and cannot be replaced in this time period), we assume total replacement. With that in mind, figure 13 displays a supply curve for demand reduction in the study region.

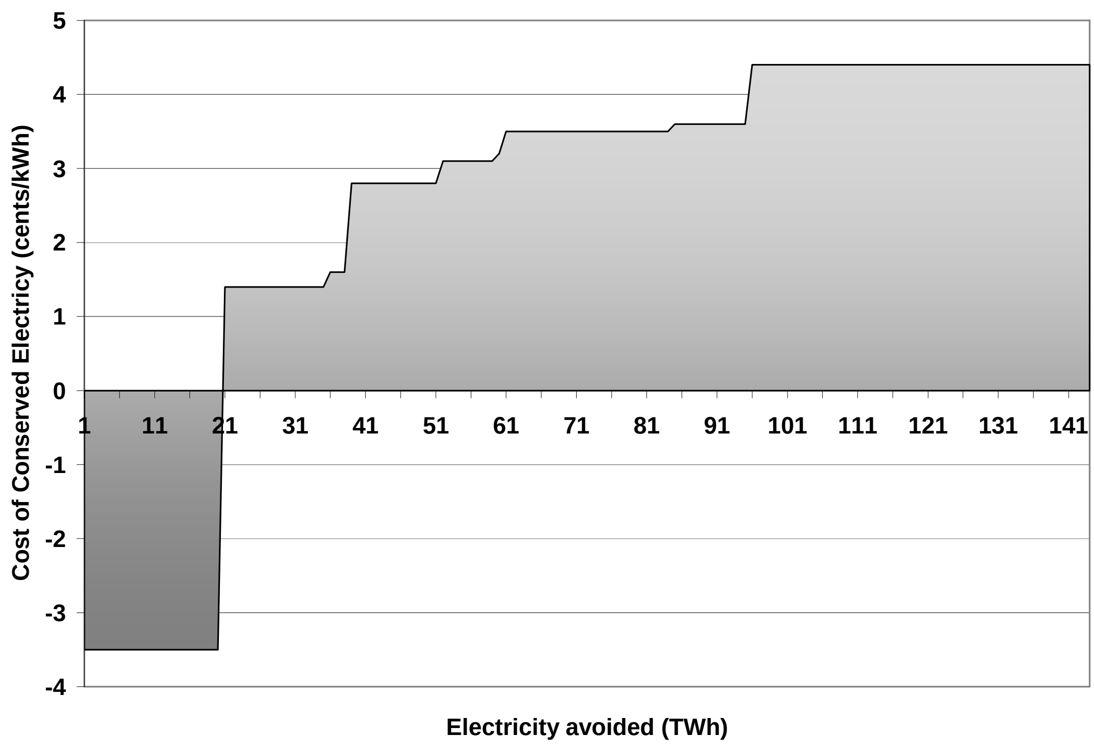


**Figure 13: A supply curve for demand cost-effective demand reduction in the study region, based on assumptions and analysis from the Interlaboratory Working Group Study.**

According to this analysis, 143 TWh of annual electricity production could be avoided, or more than one third of projected demand in 2019 (thirteen years from now) assuming 1.9% annual growth.

The Minnesota Dept. of Commerce has been a leader regionally in promoting energy efficiency programs such as conservation, demand side management and peak demand reduction programs through their Conservation Investment Program (CIP). In addition, the Minnesota Public Utilities Commission has required utilities to include energy efficiency as a resource in their integrated resource plans. Xcel Energy currently invests 2% of revenues in energy efficiency programs and other regulated utilities in the state are required to invest 1.5%. Natural gas utilities are required to invest 0.5%. In 2002, rural electric coops and municipal utilities agreed to invest 1.5% for electric and 0.5% for gas revenues in CIP programs. This corresponds to roughly $50 million per year in MN spent on electricity (other funding focuses on natural gas reduction). A recent resource plan from Xcel estimates the cost of demand management at 0.6 cents per avoided kWh.

The Wisconsin Public Service Commission set up a public benefits program in 2000 called Focus on Energy. Utilities collect a surcharge from customers and pay those dollars to the Dept. of Administration which funds the Focus on Energy program and the Home Energy Plus program which provides weatherization services for low income customers. Focus on Energy projected an overall cost benefit of over 5.7 for their programs.

The Energy Center of Wisconsin recently completed a study called “Energy Efficiency and Customer-Site Renewable Energy: Achievable Potential in Wisconsin 2006-2015”. They concluded that an average of $75 to $121 million per year could be spent cost effectively on statewide programs to improve energy efficiency in Wisconsin. In fiscal year 2005, the spending level was $38 million.

There is clearly the potential for vastly altering the demand forecast through demand reduction.

## Electricity Technologies

### 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.[10] From 1997 to 2001, electricity 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.[11]

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. A 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)[12].[13] 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 through a comparison of predicted wind resources with actual wind measurements.[14] 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. Land areas are ranked on a scale of 1-7 according to wind speed and other criteria, with only certain ranks considered appropriate for commercial development.

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[10] 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 electricity sector.
[11] C. R. D. A. Randall Swisher, Julie Clendenin, Proceedings of the IEEE 89, 1757 (December 2001, 2001).
[12] M. N. S. D.L. Elliott, in International Academy of Science. (Kansas City, MO, 1993).
[13] 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).
[14] M. Schwartz, in ASES Solar '99 Conference. (Portland, ME, 1999).

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, and assuming appropriate rankings for commercial development. [15][16] This translates into approximately 5,225 TWh of electricity 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 would reach 59 percent of projected regional electricity demand in 2055.

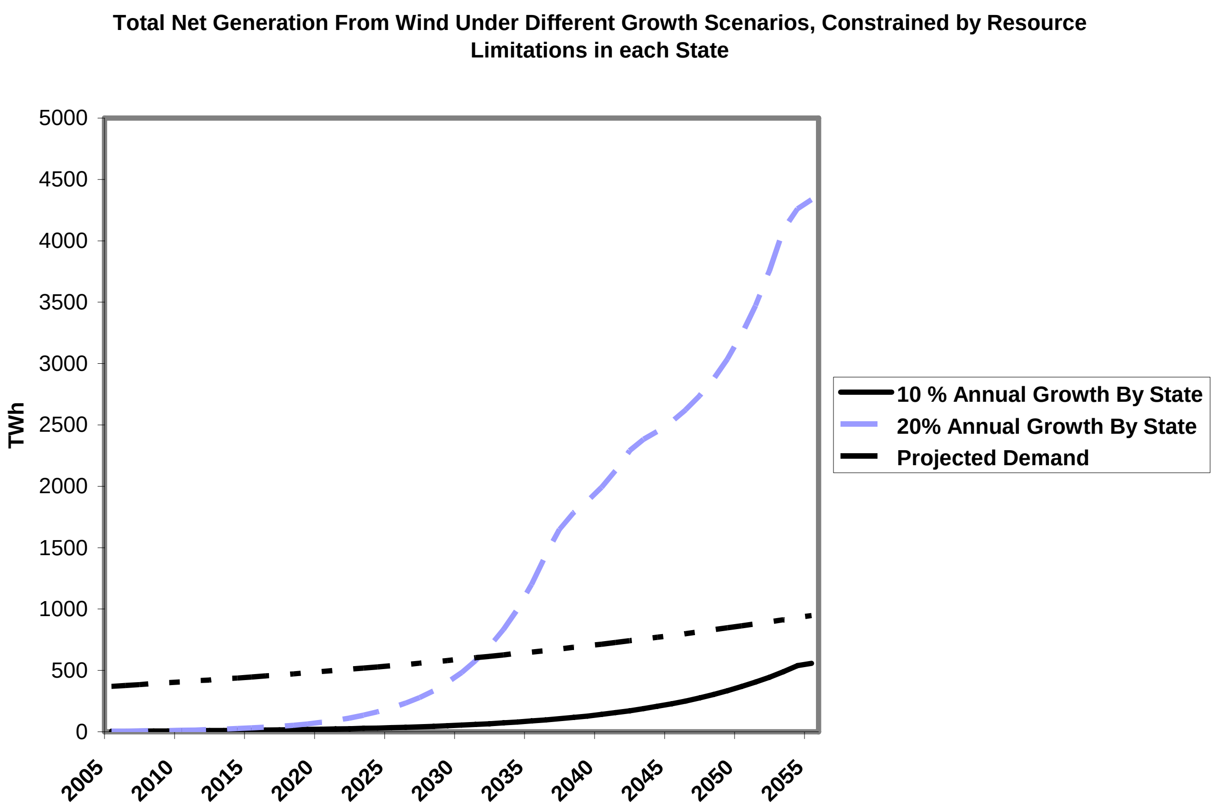


**Figure 14: The figure demonstrates the effect of allowing wind to grow (per state) at 10 and 20 percent per year for the next 50 years. Since each state in the region has limited wind resources, growth is bounded at the upward constraint of the wind resource in each state, hence the curvy lines.**

[15] GWa: GigaWatt average. Wind is a variable source of electricity, 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.
[16] 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).

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 electronics and control systems, and improvements in blade design. These factors result in both lower priced electricity 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.[17]

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 electricity 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[18][19]. 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 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 choices, because of economics and shared geography, are coal, biomass and/or hydroelectric.
- 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.[20]

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[17] C. R. D. A. Randall Swisher, Julie Clendenin, Proceedings of the IEEE 89, 1757 (December 2001, 2001).
[18] "Xcel Energy and the Minnesota Department of Commerce: Wind Integration Study- Final Report" (EnerNex Corporation, Wind Logics, Inc., 2004).
[19] "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).
[20] 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 currently meets 25% of annual electricity demand from wind, and up to 50% in certain months.[21]

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. Electricity is produced by decompressing that 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.

[21] D. M. Kammen, paper presented at the 20-50 Solution: Technologies and Policies for a Low Carbon Future., Washington DC, March 24-25 2004.

## 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, dish/engine systems and the more commonly seen photovoltaic systems.

The Power Technologies Data book[22] provides information on photovoltaic costs. 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.[23]

The National Renewable Energy Lab's Center for Renewable Energy Resources[24] 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 that would be very expensive at large scale.

[22] National Renewable Energy Laboratory. Power Technologies Data book, Third Edition. April 2005, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy
[23] L. K. John Byrne, Daniele Poponi, Allen Barnett, *Energy Policy* **32**, 289 (2004).
[24] Direct Normal Solar Radiation (Two Axis Tracking Concentrator) (http://www.nrel.gov/gis/solar.html

## C. Biomass

Biomass is likely to play a greater role in replacing natural gas, heat, and liquid fuels than electricity. There is a potentially vast biomass supply in the region. There is also potential to displace emissions from fossil fuels by sequestering carbon in soils through the production of biomass crops. Walsh (2000)[25] summarizes the efforts of researchers around the country to estimate biomass supply from various materials. They estimated that the U.S. could supply more then 500 million tons of biomass per year, and more than 120 million tons in the Northern Great Plains (see Figure 14). A 2005 study — dubbed the Billion Ton Study — conducted by the U.S. Departments of Energy and Agriculture found that improvement in energy crops such as switchgrass could more the double the annual supply to nearly 1.3 billion.[26] The estimates in Figure 14 can therefore be considered conservative because they assume no improvement in yields. Based on past improvements in crop yields, improvements in biomass crops could at least double the regional biomass supply estimate to 240 million tons per year.

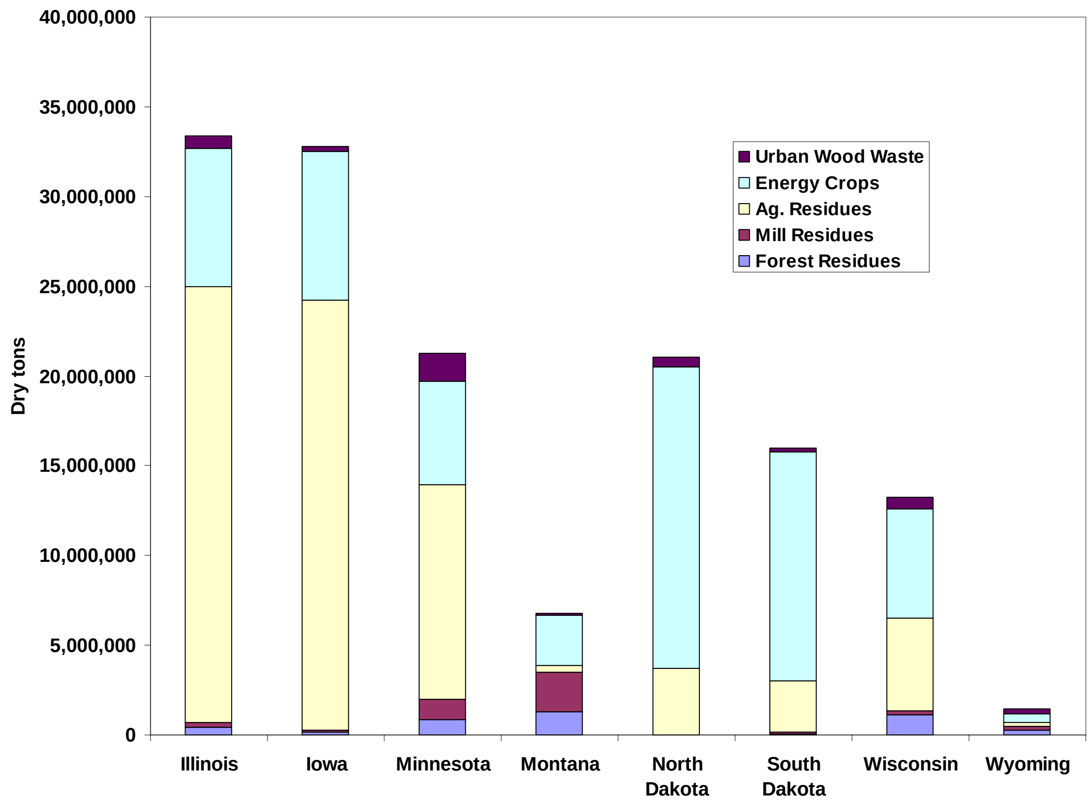


**Figure 14: Annual Supply of Biomass at $50 Per Ton or Less from Forest Residue, Mill Residues, Agricultural Residues, Energy Crops, and Urban Wood Waste by State, in Dry tons. (Source: Walsh et al. 2000)**

[25] Walsh, M., R. L. Perlack, A. Turhollow, D. de la Torre Ugarte, D. A. Becker, R. L. Graham, S. E. Slinsky, and D. E. Ray. 2000 Biomass Feedstock Availability in the United States: 1999 State Level Analysis. Oak Ridge National Laboratory. http://bioenergy.ornl.gov/resourcedata/index.html

[26] Perlack, R., L. Wright, A. Turhollow, R. Graham, B. Stokes, D. Erbach, Biomass as a Feedstock For a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion Ton Supply. April 2005. US Department of Energy and US Department of Agriculture.

Total energy consumption in the region was about 10 quads[27] in 2001[28]. The total biomass resource, minus current consumption of biomass for energy, is about 2.5 quads of energy, or about 25 percent of regional energy consumption in 2001. With improvements in biomass crop yields, this could double to 50 percent of total regional energy consumption.

Biomass, with the right technology, can replace any type of fossil fuel. To replace coal, biomass needs only to be burned. Combustion of biomass for heat rather than electricity is the most common use today. The wood and paper products industry burns waste wood to produce electricity and process heat. Biomass can be burned as a mixture with coal in a power plant – a process called "co-firing". This is being done at the Chariton Valley Biomass Project in southern Iowa.

Corn ethanol is a rapidly growing liquid fuel in the Midwest. Production in 2005 was more than 4 billion gallons[29], enough to replace about 15 % of regional gasoline and diesel use,[30] and using about 26% of the regional corn crop.[31] At current rates of growth, the ethanol industry will double by 2010[32], presumably producing more than 8 billion gallons of ethanol and using more than half of the region's corn supply. Many factors remain unclear, including whether more land will be recruited into corn production, whether corn prices will respond to increased demand by the ethanol industry and make corn ethanol prohibitively expensive, or whether improved corn yields will increase the corn supply. Demand for liquid fuels is likely to increase in the future as well. Corn has many uses other than fuel ethanol production, which can influence its price. Federal incentives, a federal Renewable Fuels Standard, and state policies all encourage corn ethanol production.

Technical and economic limits exist to the supply of corn ethanol, and the nation clearly cannot feasibly satisfy its liquid fuel demand from corn ethanol alone. Ligno-cellulosic biomass—feedstocks other than those currently derived from the starch of corn kernels, soy beans and other grains and seeds—has the potential to greatly increase the supply of renewable liquid fuels. If all of the biomass estimated in the analysis in Figure 1 were used to produce cellulosic ethanol, it would be more than twice current regional corn ethanol production, and half of current regional liquid transportation fuel consumption.

Biomass can replace a variety of fossil fuels through a technology platform called gasification. When biomass is heated in the absence of oxygen it turns into a mixture of carbon monoxide and hydrogen. This gas can be transformed into a natural gas substitute, or used as the precursor to other chemicals – including synthetic diesel fuel or alcohols such as ethanol. Two ethanol plants in Minnesota that rely heavily on natural gas are

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[27] A quad is $10^{15}$ British thermal units of energy.
[28] U.S. Energy Information Administration 2003 Form Data
[29] Renewable Fuels Association
[30] According to U.S. Energy Information Administration data from 2003 Form Data
[31] According to data from the U.S. Department of Agriculture National Agriculture Statistics Service
[32] "Amber Waves" US Department of Agriculture Economic Research Service
http://www.ers.usda.gov/AmberWaves/April06/Features/Ethanol.htm

installing biomass gasifiers that will eventually replace up to 90 percent of the natural gas they currently use.

Biogas, a product of anaerobic digestion of manure, can be a source of heat, electricity (and hydrogen) for use on the farm. For example, the Haubenschild Farm in Princeton, MN[33] uses manure from a 1,000 cow operation to produce methane that fuels a caterpillar diesel engine, which in turn provides heat and power for the entire dairy operation while selling electricity to East Central Energy. In addition to displacing fossil heat and power, digesters can play an important role in manure and odor management systems.

Biomass is currently widely used as a source of heat in residential applications (fireplaces and woodstoves) and as a source of industrial heat, particularly in the wood and paper products industry. Biomass could be used for heat in other applications as well, and could be used more efficiently where it is now used.

Finally, biomass can replace a multitude of chemicals, plastics, and other non-energy products that are currently manufactured from petroleum. Wal-Mart's decision to begin using only plastic bags manufactured from corn-derived PLA (poly-lactic acid) plastic represents a high-profile example of this trend and its future potential in the marketplace.

The extent to which biomass helps achieve broader environmental goals depends to a large degree on how it is produced. Biomass can be produced in a way that degrades soil, decreases wildlife habitat, and causes water pollution. It can also be produced in a way that improves soil, increases wildlife habitat, and decreases pollution. Replacing the equivalent of one third of current petroleum consumption with biomass will mean placing many millions of acres of land into production of biomass crops. Whatever positive or negative impacts the production methods have, then, will be magnified over many millions of additional acres. It is crucially important that any strategy for increasing the use of biomass assures that the biomass is produced in a way that enhances soil health, maintains wildlife habitat and recreational opportunities, and improves water quality.

Biomass can have an impact on greenhouse gas emissions in two ways. The first is by replacing fossil fuels. Biomass is plant material, and grows by capturing carbon dioxide from the air and transforming it into plant tissue through photosynthesis. When biomass is burned, that carbon dioxide is released back into the atmosphere. Biomass used for energy is said to have near zero net emissions of carbon dioxide – because it only re-releases carbon dioxide it initially captured during its growth cycle. When biomass energy replaces fossil energy, it replaces a net-carbon-emitting resource with a non-net-carbon-emitting resource. This helps to reduce atmospheric carbon levels.

Biomass can also reduce greenhouse gas emissions through terrestrial sequestration. Typically, not all of an energy crop is harvested. Crops such as switchgrass, big blue-stem or other grasses have extensive root systems. Although part of the plant is harvested, the root system continues to grow – capturing carbon from the air and storing it

[33] http://www.epa.gov/agstar/resources/agri.html

underground. This is called terrestrial sequestration, and also helps to avert climate change.

Various land management practices can play a role in sequestering atmospheric carbon dioxide and thereby reducing overall emissions. Ruttan Lal of Ohio State University argues that adoption of recommended management practices (RMPs) on soils of agricultural, grazing, and forestry ecosystems, and conversion of degraded soils and drastically disturbed lands to restorative land use, could lead to sequestration at an annual rate of 144-288 Tg per year,[34] or 528 – 1056 Tg of $CO_2$ equivalent. Since the U.S. emitted 7,122.1 Tg of $CO_2$ equivalent in total greenhouse gas emissions in 2004, recommended Management Practices could offset 7 – 15 % of U.S. emissions.

The same management practices that result in carbon sequestration are often associated with other benefits. No-till and reduced-till agriculture, for example, is associated with improved crop yields, better soil aeration, and reduced soil erosion and run-off. It also reduces on-farm energy use and saves money for farmers.

Land management and biomass production can be paired together to mutual benefit, and to increase the total potential of the agricultural sector to contribute to energy and climate solutions. Increased production of switchgrass, for example, would result in increased soil sequestration of carbon while replacing fossil fuels with renewable biomass.

In summary, biomass could replace one fourth of the region's total energy consumption without any advances in crop yields. The economics of biomass are such that it can likely compete with any fossil fuel under various circumstances. Many factors will determine whether biomass is used primarily to replace natural gas, electricity (coal), or petroleum. It will likely replace all of these conventional energy resources to varying degrees, depending on relative costs of these resource compared to biomass feedstock alternatives and on the nature and pace of commercialization of biomass technologies. Biomass, given conservative assumptions about yields and land recruitment for bioenergy crops, can replace at least 25% of total regional energy consumption by 2050.

Soil sequestration can displace a significant proportion of regional CO2 emissions, although precisely how much is unclear. Given that the upper Midwest has a higher than average proportion of the nation's crop land and relatively less industry than other regions of the country, it is likely that terrestrial sequestration could off-set more than 7-15% of current regional GHG emissions.

[34] Lal, R., R.F. Follett, and J.M. Kimble. 2003 Achieving Soil Carbon Sequestration in the United States. Soil Science; 168:827-845.

**D. Hydroelectric**

In 2004 there were 52 utility-scale hydroelectricity 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 electricity behind coal and nuclear. Hydroelectric generation dominates electricity 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 electricity by its hydroelectric facilities, in addition to exporting both to other Provinces and to the US.

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.[35] [36]

Despite studies showing additional hydroelectric potential in U.S. states in the region, the authors are not aware of any new projects being planned.

Manitoba Hydro, the Canadian Crown Corporation that controls all electricity 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.

Manitoba Hydro has proposed three major hydropower projects totaling about 2,200 MW over the next 15 years. They have estimated a long term potential of 5,000 MW of additional hydropower production in the region.

- Wuskwatim Generating Station: A 200 MW station with three generator units on the Burntwood River near Thompson, Manitoba. Proposed in-service date, pending referendum approval of the partnership agreement by NCN members, would be 2012.
- Gull Generating Station (now known as Keeyask): 630 MW station planned at a site on the Nelson River, 30 km west of Gillam. Manitoba Hydro is currently discussing with the Tataskweyak Cree Nation a partnership agreement, and it has initiated discussions with three other First Nations in the region. The earliest possible in-service date for the project is 2011/2012. The Gull (Keeyask) Generating Station Project would require associated transmission facilities.
- Conowapa Generating Station: 1380 MW station at a site on the Lower Nelson River, 28 km downstream of Limestone Generating Station, and 90 km downstream of Gillam. The projected in-service date is 2017. The project would

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

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

require major transmission facilities associated with the export interconnection project. No final design development or construction decisions have been made, nor have the routes of power lines, long distance HVDC lines, or the location of converter stations been determined.

**Table 3: Additional hydroelectricity potential in the study region**

| | available potential (MW) | | | available low head/low power (MW) | | | |
|---|---|---|---|---|---|---|---|
| | high power | high head/low power | low head/low power | conventional turbine | unconventional systems | microturbine | Total MW |
| Illinois | 1146 | 39 | 393 | 103 | 100 | 190 | 1578 |
| Iowa | 361 | 49 | 492 | 183 | 108 | 201 | 902 |
| Minnesota | 445 | 166 | 422 | 139 | 72 | 211 | 1033 |
| Manitoba | 5000 | | | | | | 5000 |
| Montana | 1515 | 897 | 596 | 208 | 91 | 297 | 3008 |
| North Dakota | 0 | 0 | 11 | 0 | 0 | 11 | 11 |
| South Dakota | 0 | 0 | 169 | 0 | 0 | 169 | 169 |
| Wisconsin | 602 | 138 | 402 | 131 | 68 | 203 | 1142 |
| Wyoming | 1904 | 801 | 468 | 194 | 47 | 227 | 3173 |
| Great Plains | 10973 | 2090 | 2953 | 958 | 486 | 1509 | 16016 |

Source: http://www.hydropower.inl.gov/resourceassessment

If all the hydroelectric capacity were developed in the region, an additional 16,016 MW of capacity, or around 70 TWh would be possible, 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.[37] If all hydroelectricity were developed in the region, and all existing capacity was maintained, it could supply approximately ten percent of projected demand in 2055. Hydroelectricity, while relatively low in cost and carbon neutral, represents a small proportion of total regional power generation potential.

[37] The model predicts a lower rate of growth than 1.9% annual growth based on current trends towards greater economic efficiency in terms of electricity demand per unit of Gross State Product. The model predicts Business as Usual demand in 2055 of 520 thousand MWh.

## E. Coal

Coal plays the largest role of any resource in electricity 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 a carbon-constrained world, 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 the remainder. 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 electricity accounted for around 260 million tons, or 43 percent of total carbon dioxide emissions from all sectors in the study area, making this an obvious emissions-reduction target.

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.

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.

An analysis of the coal-fired 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 15 illustrates the pattern of possible plant retirements in the region.

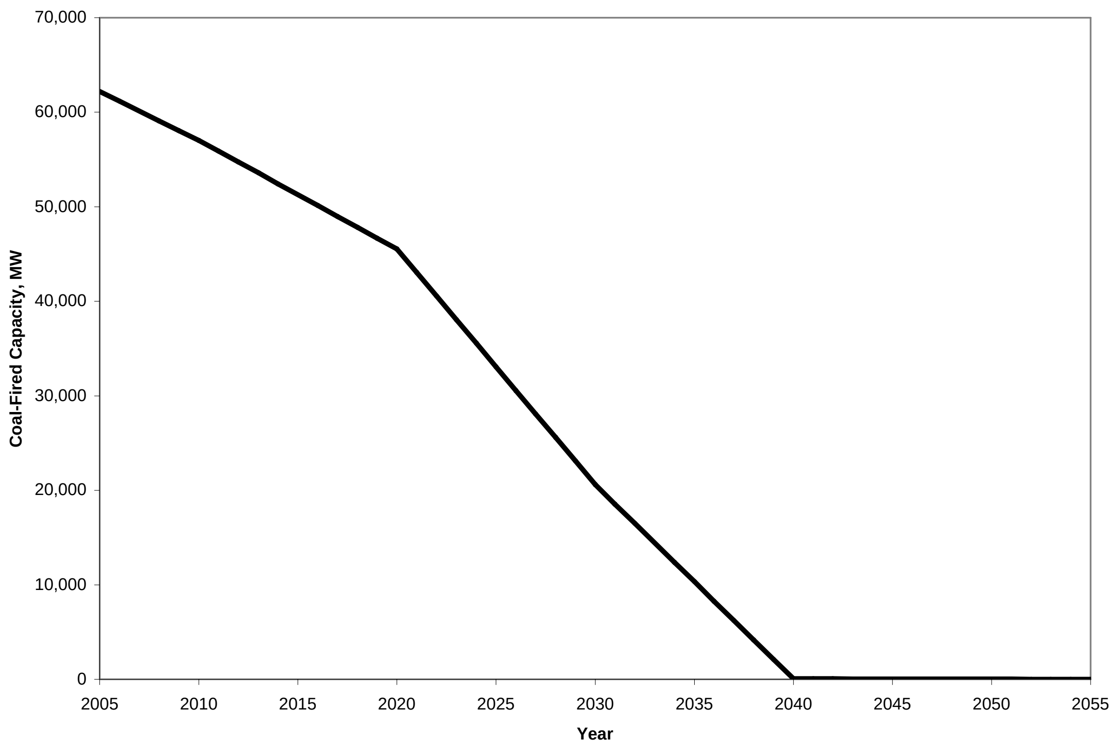


**Figure 15: Retirement of coal-fired capacity in the region, assuming a 50 year plant life.**

The goal of reducing carbon dioxide emissions by 80 percent relative to 1990 levels by 2055 requires more than just shifting from pulverized coal to gasification. 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.[38] 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 electricity 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.

[38] Ancillary studies

## 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.[39] 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.[40] 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 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. Currently 40% of the $CO_2$ produced at the facility is being captured and stored in the Weyburn oil fields. Several smaller scale projects 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. 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

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

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)[41] 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. [42] 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.

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 less costly than capture from any of the current or near-term power generation technologies.[43] 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.[44] 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.[45] 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.[46] A similar study by Herzog and Golomb indicate that carbon capture can

[41] U.S. Department of Energy, National Energy Technology Laboratory, Carbon Sequestration, Technology Roadmap and Program Plan – 2004, April 2004.
[42] U.S. Department of Energy, National Energy Technology Laboratory, Carbon Sequestration, Technology Roadmap and Program Plan – 2004, April 2004.
[43] Energy Information Administration, <http://www.eia.doe.gov/oiaf/1605/ggrpt/geologic.html>.
[44] Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/ggrpt/geologic.html.
[45] http://www.netl.doe.gov/coal/Carbon%20Sequestration/kidspage/index.html
[46] http://www.netl.doe.gov/coal/Carbon%20Sequestration/kidspage/index.html

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. [47] 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.

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 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.[48] Separate costs for transport and injection are broken out in Table 8.

**Table 4**
**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[49] 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

[47] 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>
[48] Executive Summary – find source
[49] 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.

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.[50] 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 electricity 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.[51] 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 2055.[52] 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.

[50] 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>

[51] 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.

[52] Using net generation of 625,000 GWh in 2055, and 0.09 tonnes/MWh in 2055 using IGCC with capture and sequestration.

## G. Natural Gas

In the Upper Midwest region, natural gas in the electricity sector 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 electricity. 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 electricity sector is expected to increase in the future.[53] 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 are expected to increase significantly over the next several decades.

There are 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 electricity production in 2004 was generated with steam turbine units.

Gas turbine units accounted for more than 37 percent of the gas-fired electricity 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 existing steam generation units, due to the higher efficiencies that can be

[53] Energy Information Administration, Annual Energy Outlook 2005, <2005, http://www.eia.doe.gov/aoif/aeo/demand.html>.

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, contributing roughly half the emissions of typical coal technologies.[54] 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.

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.

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.[55] Carbon capture and sequestration is paired with coal IGCC electricity 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.

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

## 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 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 .

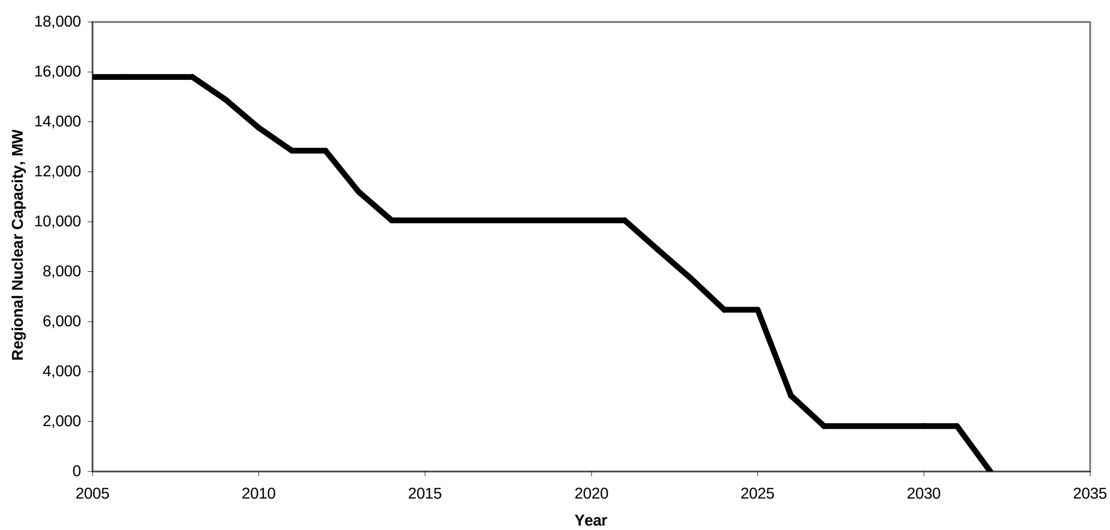


**Figure 16: Retirement of regional nuclear plants, assuming a 50 year life.**

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.[56]

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[57] 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.

[56] Energy Information Administration < http://www.eia.doe.gov/oiaf/aeo/electricity.html>.
[57] Assumes heat content and emissions characteristics of sub-bituminous coal.

## I. Electricity Technology Summary

A summary of the electricity 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 and levelized costs were calculated using the model created for this research project and described in the next section.

**Table 5**
**Summary of Electricity Production Technologies**

| Technology | Installed Cost ($/kW Capacity) | Fixed O&M ($/kW) | Heat Transfer Efficiency (%) | Net $CO_2$ Emissions (tons/ MWh) | Levelized cost of electricity ($/MWh) (Plant gate) |
|---|---|---|---|---|---|
| Dedicated Biomass IGCC | 1,659 | 48.6 | 38% | 0 | $65 |
| Waste Biomass | 1,443 | 104.0 | 25% | 0 | $46 |
| Old Pulverized Coal | 0 | 25.1 | 32% | 1.14 | $20 |
| New Pulverized Coal | 1,167 | 25.1 | 36% | .94 | $40 |
| Coal IGCC | 1,349 | 35.2 | 41% | 0.88 | $43 |
| IGCC w/CCS | 1,873 | 41.4 | 35% | 0.10 | $57 |
| Conventional Hydro (turbine) | 1,320 | 12.7 | N/A | 0 | $28 |
| Natural Gas – Advanced Gas Turbine | 365 | 95.9 | 34% | 0.39 | $44 |
| Nuclear | 1,744 | 61.8 | N/A | 0 | $49 |
| Distillate Fuel Oil – Advanced Turbine | 365 | 95.9 | 34% | 0.59 | $111 |
| Solar Photovoltaic | 3,981 | 10.6 | N/A | 0 | $265 |
| Wind | 1,091 | 27.6 | N/A | 0 | $48 |

The costs shown are in 2005 dollars. Overnight costs represent the cost of new projects, initiated in 2005, 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.[58] Method for calculating levelized costs is described in appendix II.

[58] Energy Information Administration, Assumptions to the Annual Energy Outlook 2005.

## Scenario analysis

### A. Introduction to Scenarios

The model was used to generate a variety of scenarios for achieving an 80% reduction in CO2 emissions relative to 1990 levels. A detailed description of the model and its assumptions are found in Appendix II.

Briefly, the model predicts the impact of a wide variety of variables on electricity supply, cost, technology choice and $CO_2$ emissions. In particular, users can model the impact of various policy choices on the characteristics of the electricity system over a 50 year time frame. The model is underpinned by a list of all existing power plants in the region (see page 7 for a map of the region). It is governed by rules and equations. Every year, power plant operators make decisions – based on policy, resource availability, economics, fuel costs, and other variables – about whether to keep a plant operating or to switch to a different technology. Technology assumptions are summarized in Table 5 above.

The model strives to be flexible, transparent, and real-time. Users are confronted with their assumptions and their impact on the world. If any of the default assumptions in the model are unacceptable to the users, they are free to run their own assumptions. Because the model runs in real time, users can immediately see the results of their assumptions, and can make changes accordingly.

Examples of policies that users can impose include: taxes and subsidies on electricity and on individual technologies, renewable energy standards, CO2 taxes and standards, and demand management. Other variables that the user can adjust include technology capital and operating cost, fuel costs and cost trends, Gross State Product and Gross State Product growth, demand elasticity, debt/equity ratios and interest rates, transmission costs, and technology life.

The model was developed in tandem with the development of the inventory and resource assessments described in this report. For the final section, the model was used to create scenarios for how the region could reduce its CO2 emissions by 80% relative to 1990 levels and how that would impact the cost of electricity, total expenditures for electricity, and the mix of resources and technologies used to generate electricity.

Two categories of $CO_2$ reduction interventions were explored. One category of scenarios is policy driven, where either $CO_2$ standards or taxes are implemented to change the mix of generating technologies and decrease $CO_2$ emissions. These scenarios are neutral with regard to technology, automatically picking the lowest cost technology available (with availability depending on supply and whether a technology meets a $CO_2$ standard).

The second category are technology and resource-driven in the sense that certain technologies/resources are mandated at various levels of production according to possible preferences based on politics and culture in the region. These scenarios explore ways that different mixtures of generating technologies can be deployed to meet $CO_2$ reduction goals.

A note regarding the model and "tipping points". The model assumes that producers choose the cheapest technology available at the time of plant replacement, subject to existing policies, prices, resource constraints, and other rules. Since many technologies are very close together in levelized cost, small changes can have an enormous impact on the electricity mix. For one example, given our baseline assumptions the levelized cost of nuclear and wind electricity are very close with nuclear coming in slightly cheaper. With an approximated production tax credit, however, wind reaches a tipping point where it is cheaper than nuclear. If carbon emissions are restricted, either through taxes or standards, one of these technologies becomes dominant depending on which is cheaper. You only get a mixture of the two if one is restricted in some way, for example by mandating that no more than 20% of total net generation can come from wind.

Although a variety of variables can be altered, for the purposes of this exercise we only manipulated "policy" variables.

The default assumptions for costs are worth investigating through sensitivity analysis at another time, but are beyond the scope of this study.

## B. Business As Usual

To determine a business as usual projection, the authors attempted to set parameters to match as closely as possible current policies and costs.

### Policies:

**Demand Management**
Several states have programs designed to reduce demand, primarily by requiring utilities to spend money on demand reduction. Minnesota utilities are required to spend about $50 million per year on demand management (not including demand management requirements for natural gas utilities). Wisconsin utilities, as of March 22, 2006, are required to spend $85 million on demand management programs, although it is unclear how much will be spend on electricity demand versus natural gas demand management. We assume half ($43 million) is spent on the electricity sector. Illinois has a public benefit fund that allocates $3 million per year on energy efficiency.

In the BAU we allocate $50 million in Minnesota, $43 million in Wisconsin, and $3 million in Illinois for demand reduction, a total of $96 million for the region per year. It is assumed that demand reduction can be purchased for $10 per MWh of avoided electricity.[59]

**Production tax credit**
Biomass IGCC (assumed to be closed loop dedicated biomass crops), wind, and photovoltaic receive an approximation of a production tax credit of 1.9 cents/kWh[60]. Waste biomass (assumed to be open loop waste biomass) and hydroelectric receives a production tax credit of .9 (approximately half the 1.9 cents/kWh production tax credit).

**Renewable energy standards**
The PTC is not enough to make wind cost-competitive with pulverized coal, the cheapest technology in the model. This implies that wind development is being driven primarily by renewable energy standards rather than the production tax credit. Within the region, Montana (15%), Wisconsin (10%), MN (10%), Iowa (2%), and Illinois (8%) have renewable energy standards, objectives or goals. Assuming full implementation, this translates into 8 % regionally[61]. Since hydroelectricity is typically not an eligible source of electricity under renewable energy standards, and wind is the cheapest source of renewable energy after hydro, we assume that these renewable energy standards are primarily satisfied by wind. We therefore model existing renewable energy standards by mandating that 8% of regional energy come from wind.

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[59] This is a conservative assumption considering that Minnesota's Conservation Investment Program averages $6/MWh of avoided power.
[60] Wind plants currently receive a production tax credit of 1.9 cents/kWh for their first ten years of operation. Since wind plant operate for 40 years in this model, the tax credit is divided by 4 to approximate the impact of the PTC over the lifetime of a plant.
[61] A regional average renewable energy standard is weighted by the 2004 electricity demand of each state in the region.

**Maximum technology penetration**

Natural gas capped at 5% of total net generation in all scenarios. It currently represents about 2% of regional net generation, and functions as peaking power supply only. The model tells only a base load story. 5% is arbitrary, and involves an increase over current levels. This limitation is based on the fact that there is limited natural gas production in the region and the authors are telling a regional energy system story. The authors also doubt that significant new supplies of natural gas could be imported in order to provide dramatic increases in electricity production. There is also significant demand for natural gas as a source of heat. Dramatically increasing natural gas consumption in the electricity sector would likely impact price.

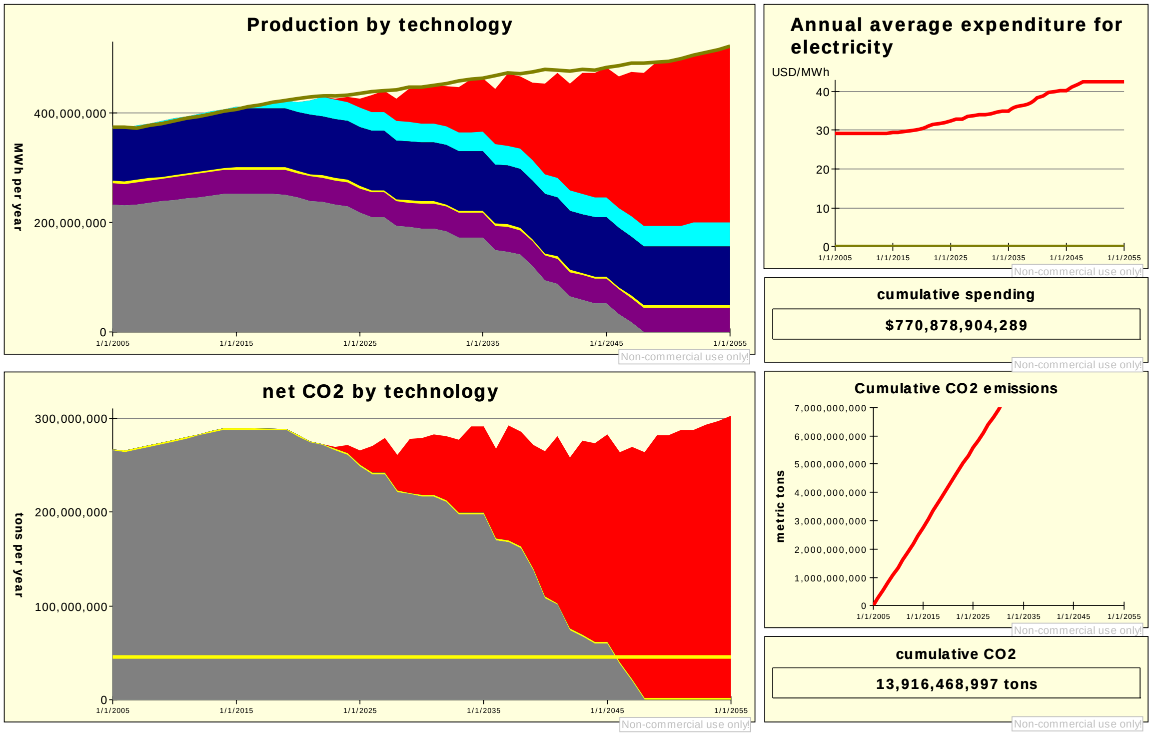
Although no new nuclear capacity is added in this scenario, the economics of nuclear power favor the plants already existing. The model makes more use of the existing nuclear power plants and increases production from 96 million MWh in 2005 to 107 million MWh in 2055.

Hydroelectricity is allowed to increase moderately to account for approximately 2500 MW of new capacity planned in Manitoba. There is no hydro planned in the U.S. states in the region, although Idaho national laboratory estimates considerable undeveloped potential.

**BAU results**

Hydroelectric is the cheapest technology, but it quickly reaches its regional cap. New pulverized coal is the second cheapest technology, and remains dominant. As old pulverized coal plants retire, they are replaced by new ones. Wind increases to meet a regional renewable energy goal of 8% with steadily increasing demand. Some nuclear plants retire. Hydroelectricity increases modestly. Natural gas remains roughly constant.

## Figure 17: Business as Usual scenario




**<u>Key to Model Printout</u>**

**Production by technology (top to bottom):**

Red – New Pulverized Coal
Light blue – Wind
Dark blue – Nuclear
Yellow – Natural gas
Purple – Hydro
Gray – Old pulverized Coal
Black – Waste Biomass

**Net $CO_2$ by technology (top to bottom):**

Red – New Pulverized Coal
Yellow – Natural Gas
Gray – Old Pulverized Coal

**Results:**

- Meets $CO_2$ goal: No
- Average cost of electricity in 2055: $42/MWh
- Cumulative cost of electricity over 50 years: $771 billion
- Production in 2055: 521 million MWh

## C. CO2 Standard

In this model, a $CO_2$ standard regulates the emissions of an individual plant, and is based on emissions of $CO_2$ per unit of power produced, or per unit of fuel input. Table 6 ranks emissions per MWh by technology.

**Table 6: Emissions by technology by electricity output.**

| Technology | $CO_2$ emissions (US tons / MWh output) |
|---|---|
| Old pulverized coal | 1.14 |
| New pulverized coal | 0.94 |
| Coal IGCC | 0.88 |
| Distillate Fuel Oil | 0.59 |
| Natural Gas | 0.39 |
| Coal IGCC with sequestration | 0.10 |
| Biomass | 0.00 |
| Waste biomass | 0.00 |
| Hydro | 0.00 |
| Nuclear | 0.00 |
| Photovoltaic | 0.00 |
| Wind | 0.00 |

There is a precedent for this policy approach. California passed a bill in November 2005 in order to "prevent long-term investments in power plants with GHG emissions in excess of those produced by a combined-cycle natural gas power plant." This would effectively ban all use of coal without capture and storage of carbon dioxide.

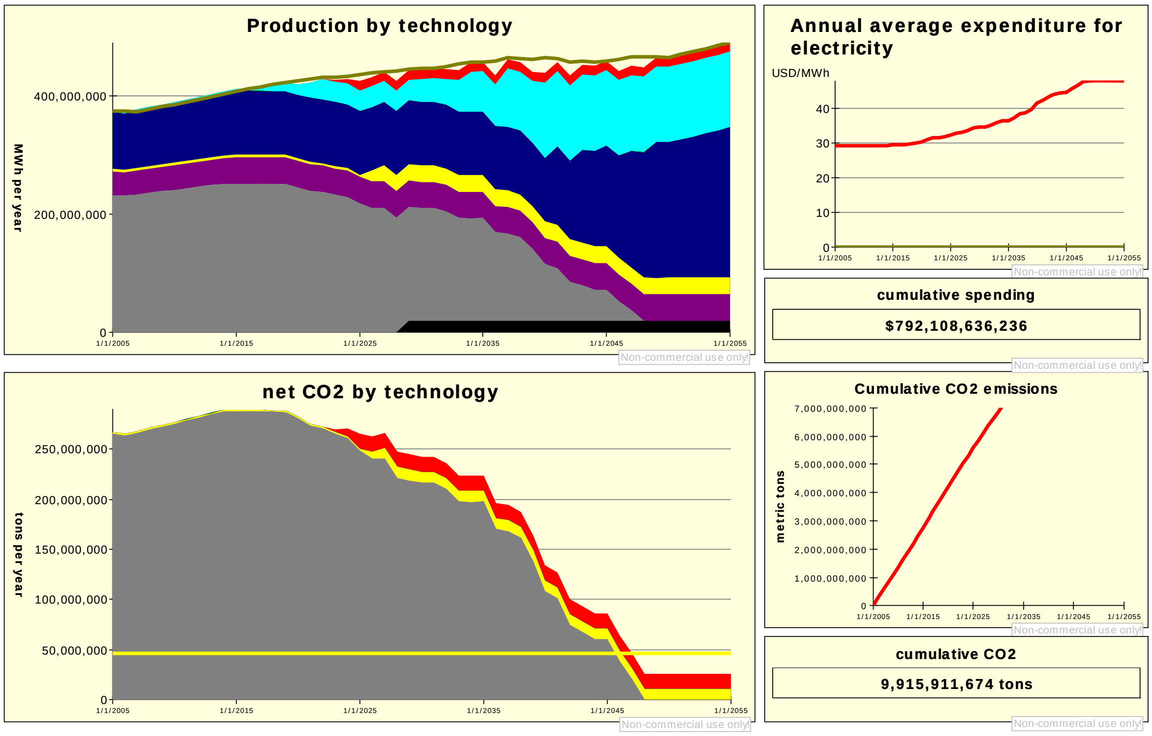
Standards could be added at one time, or phased in gradually. They can be set at different levels to allow or ban certain technologies. The implications of various levels of standard are clear from looking at table 6. For example, a standard of 1 ton $CO_2$/MWh bans only old pulverized coal plants, with emissions of 1.14 tons $CO_2$/MWh. A standard of .9 tons $CO_2$/MWh bans all pulverized coal plants, but allows IGCC plants. A standard of .85 tons $CO_2$/MWh bans all coal technologies except for IGCC with carbon capture and sequestration (CCS). A standard of .39 tons $CO_2$/MWh is required to ban natural gas.

In this scenario, a CO2 standard is added beginning in 2015 and gradually made stricter until 2055.

**Main assumptions:**

All assumptions the same as BAU, except for the $CO_2$ standard.

**Figure 18: The impact of adding a relatively modest standard in 2015 and gradually decreasing it in 10 year intervals. 2005-2015: no standard; 2015-2025: max 1 tons CO2/MWh; 2025-2035 – max .8 tons CO2/MWh; 2035-2045 – max .6 tons/MWh; 2045-2055 – max .4 tons/MWh.**




**<u>Key to Model Printout</u>**

**Production by technology (top to bottom):**
Red – New Pulverized Coal
Light blue – Wind
Dark blue – Nuclear
Yellow – Natural gas
Purple – Hydro
Gray – Old pulverized Coal
Black – Waste Biomass

**Net $CO_2$ by technology (top to bottom):**
Red – New Pulverized Coal
Yellow – Natural Gas
Gray – Old Pulverized Coal

- Meets $CO_2$ goal: Yes
- Average cost of electricity in 2055: $48/MWh
- Cumulative cost of electricity over 50 years: $792 billion
- Production in 2055: 490 million MWh

**D. CO2 Tax**

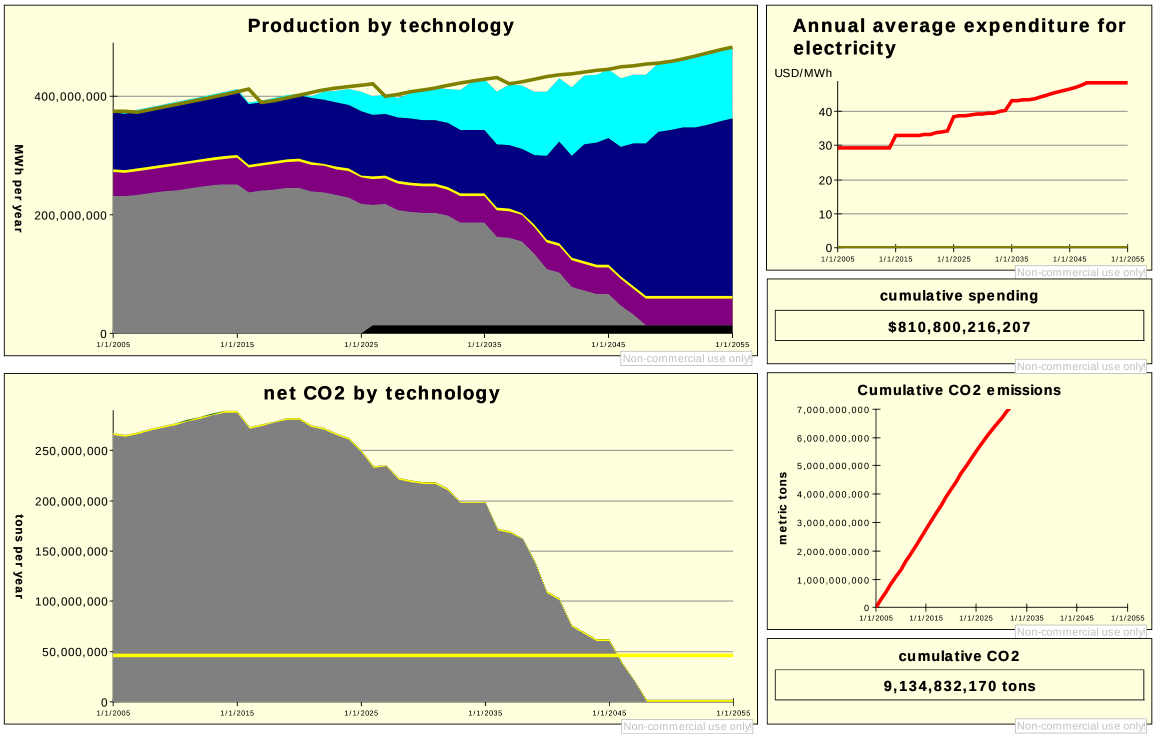
A $CO_2$ tax can also be used to raise the cost of $CO_2$ emitting technologies, and therefore alter the relative cost of technologies to favor non-emitting technologies. In this scenario, a $CO_2$ tax is gradually increased over fifty years. A $CO_2$ tax has a profound impact on the relative cost of various energy technologies.

Table 7 illustrates the impact of various levels of $CO_2$ taxation on the levelized cost of electricity. Hydroelectricity is the cheapest form of electricity at all levels of tax, but this resource is constrained and cannot become the dominant technology. Pulverized coal is the default technology with no carbon tax. This remains true with a \$2/ton $CO_2$ tax. At \$4/ton the balance shifts slightly, as the levelized cost of electricity from new pulverized coal plants rises above that of wind and electricity from biomass waste. At \$6/ton $CO_2$ pulverized coal's levelized cost exceeds nuclear and natural gas. At the same time, natural gas rises above nuclear. At \$10/ton $CO_2$ IGCC with CCS becomes the cheapest coal technology, but it is still more expensive than wind, nuclear, biomass waste, and hydroelectric. Dedicated Biomass IGCC does not become cost-competitive with IGCC CCS even at \$12/ton $CO_2$, but may become cost-competitive at higher levels of taxation (although it will still be more expensive than wind, nuclear, biomass waste and hydroelectric).

**Table7: Levelized cost of electricity from various technologies with $CO_2$ taxes ranging from \$0/ton $CO_2$ - \$12/ton $CO_2$. Costs include production tax credit – equivalent subsidies for wind, biomass IGCC, biomass waste, and photovoltaic.**

| | \$0/ton $CO_2$ | \$2/ton $CO_2$ (\$7/ton C) | \$4/ton $CO_2$ (\$15/ton C) | \$6/ton $CO_2$ (\$22/ton C) | \$8/ton $CO_2$ (\$30/ton C) | \$10/ton $CO_2$ (\$37/ton C) | \$12/ton $CO_2$ (\$44/ton C) |
|---|---|---|---|---|---|---|---|
| **Biomass IGCC** | 61.6 | 61.6 | 61.6 | 61.6 | 61.6 | 61.6 | 61.6 |
| **Biomass Waste** | 44.52 | 44.52 | 44.52 | 44.52 | 44.52 | 44.52 | 44.52 |
| **Old coal** | 41.39 | 45.97 | 50.55 | 55.13 | 59.7 | 64.28 | 68.86 |
| **IGCC** | 42.15 | 45.67 | 49.19 | 52.72 | 56.24 | 59.76 | 63.28 |
| **IGCC CCS** | 55.97 | 56.38 | 56.79 | 57.2 | 57.62 | 58.03 | 58.44 |
| **Hydro** | 30.45 | 30.45 | 30.45 | 30.45 | 30.45 | 30.45 | 30.45 |
| **Natural Gas** | 44.26 | 45.84 | 47.42 | 49 | 50.58 | 52.16 | 53.74 |
| **Nuclear** | 48.92 | 48.92 | 48.92 | 48.92 | 48.92 | 48.92 | 48.92 |
| **Fuel oil** | 111.46 | 113.81 | 116.15 | 118.5 | 120.84 | 123.19 | 125.54 |
| **Photovoltaic** | 261.58 | 261.58 | 261.58 | 261.58 | 261.58 | 261.58 | 261.58 |
| **Wind** | 44.74 | 44.74 | 44.74 | 44.74 | 44.74 | 44.74 | 44.74 |
| **New Coal** | 39.35 | 43.1 | 46.85 | 50.6 | 54.35 | 58.1 | 61.85 |

**Figure 19: Impact of a carbon tax added in 2015 and gradually increased. 2005-2015 - \$0/ton $CO_2$; 2015-2025 - \$3/ton $CO_2$; 2025-2035 - \$6/ton $CO_2$; 2035-2045 - \$9/ton $CO_2$; 2045-2055 - \$12/ton $CO_2$.**




## Key to Model Printout

**Production by technology (top to bottom):**
Light blue – Wind
Dark blue – Nuclear
Yellow – Natural gas
Purple – Hydro
Gray – Old pulverized Coal
Black – Waste Biomass

**Net $CO_2$ by technology (top to bottom):**
Yellow – Natural Gas
Gray – Old Pulverized Coal

**Results:**

- Meets $CO_2$ goal: Yes
- Average cost of electricity in 2055: \$48/MWh
- Cumulative cost of electricity over 50 years: \$811 billion
- Production in 2055: 483 million MWh

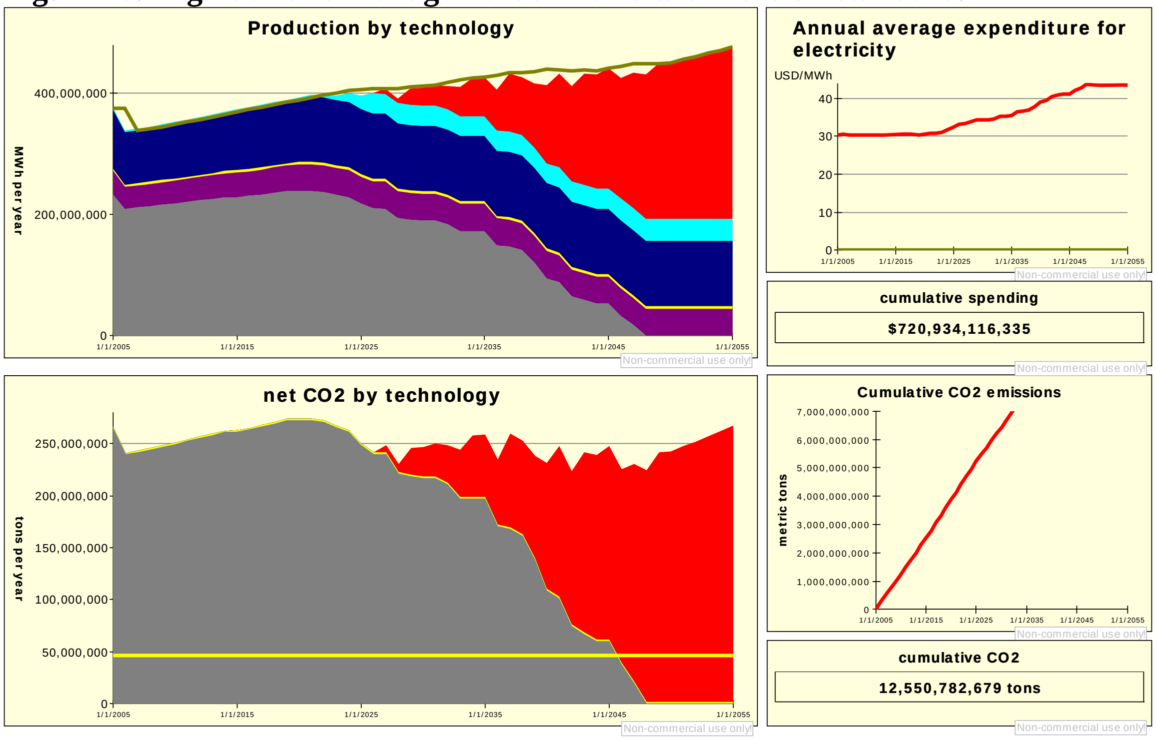
### E. High Efficiency Scenario

This scenario explores the impact of increasing spending on demand management. Various studies on demand management are discussed earlier in this report. Based on estimates in the literature, the authors feel that an average of $500 million annual regional investment in demand management, or more, could be spent cost effectively on demand management. Actual spending state by state would vary depending on population and energy consumption.

We compare two demand management scenarios – one where there is not a CO2 standard and one where there is.

**Assumptions:**
All assumptions are the same except as BAU except for the higher spending on demand management, higher average cost of demand management, and the $CO_2$ standard.

**Figure 20: High demand management scenario with no CO2 standard.**



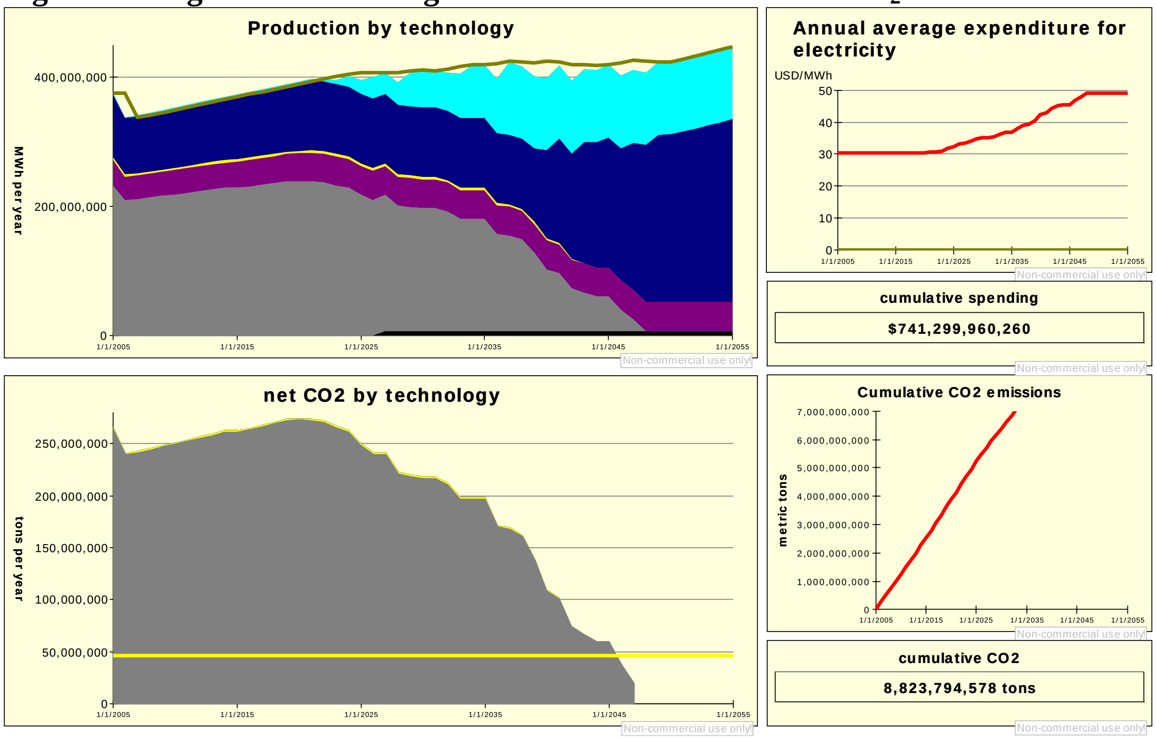

## <u>Key to Model Printout</u>

**Production by technology (top to bottom):**
Red – New Pulverized Coal
Light blue – Wind
Dark blue – Nuclear
Yellow – Natural gas
Purple – Hydro
Gray – Old pulverized Coal

**Net $CO_2$ by technology (top to bottom):**
Red – New Pulverized Coal
Yellow – Natural Gas
Gray – Old Pulverized Coal

- Meets $CO_2$ goal: No
- Average cost of electricity in 2055: $43/MWh
- Cumulative cost of electricity over 50 years: $721 billion
- Production in 2055: 476 million MWh

**Figure 21: High demand management scenario with a .2 tons $CO_2$/MWh standard.**




## Key to Model Printout

**Production by technology (top to bottom):**

Light blue – Wind
Dark blue – Nuclear
Yellow – Natural gas
Purple – Hydro
Gray – Old pulverized Coal
Black – Waste Biomass

**Net $CO_2$ by technology (top to bottom):**

Yellow – Natural Gas
Gray – Old Pulverized Coal

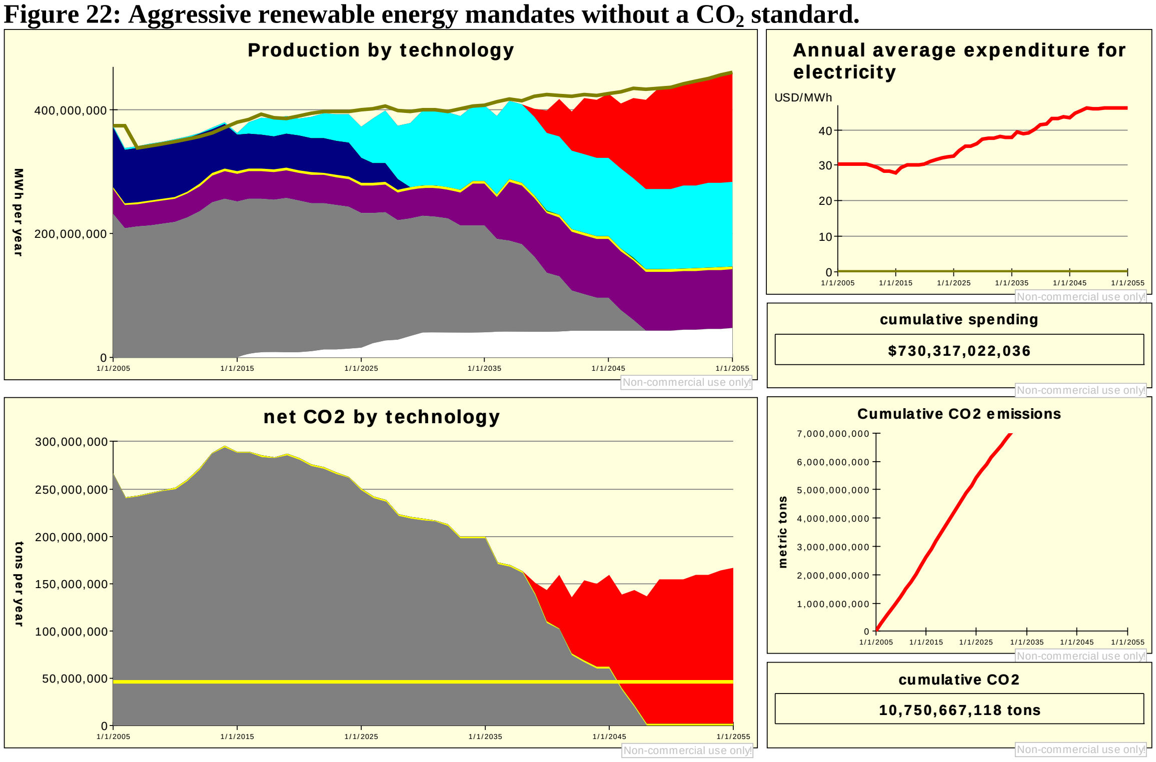
- Meets $CO_2$ goal: Yes
- Average cost of electricity in 2055: $49/MWh
- Cumulative cost of electricity over 50 years: $741 billion
- Production in 2055: 447 million MWh

## F. High Renewable Scenario

In the model, hydroelectric, wind, and nuclear are the cheapest carbon neutral energy technologies. Nuclear, since is isn't resource constrained like hydro, and constrained as a proportion of total power on the grid due to its variability, like wind, tends to dominate scenarios where $CO_2$ is reduced.

This scenario explores the possibility of mandating considerable production of energy from renewable energy. To reach this goal, wind is allowed to reach 30% penetration. Increased hydroelectric development is allowed in the U.S. – up to the resource constraints analyzed by Idaho National Laboratory. New nuclear is banned, and existing nuclear plants are phased out as they reach the end of their fifty year life. Biomass IGCC using dedicated biomass supplies is mandated at 10% of supply.

**Figure 22: Aggressive renewable energy mandates without a $CO_2$ standard.**




**<u>Key to Model Printout</u>**

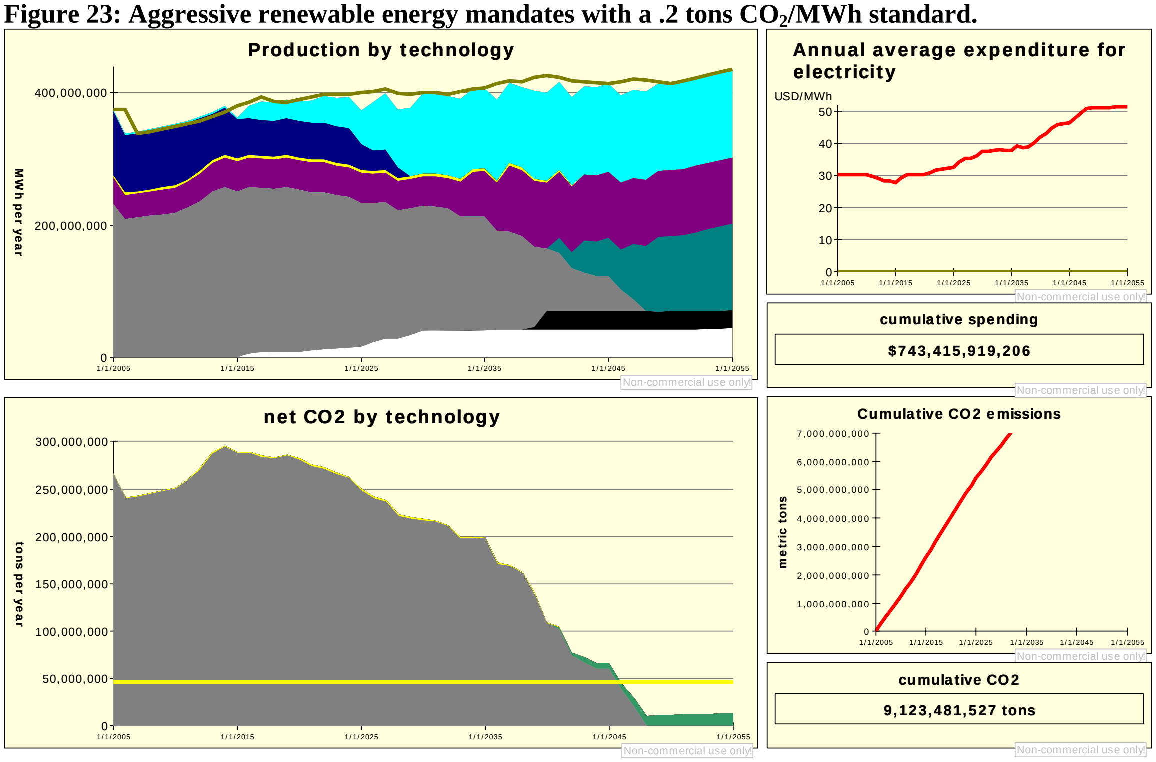
**Production by technology (top to bottom):**
Red – New Pulverized Coal
Light blue – Wind
Dark blue – Nuclear
Yellow – Natural gas
Purple – Hydro
Gray – Old pulverized Coal
White – Dedicated Biomass IGCC

**Net $CO_2$ by technology (top to bottom):**
Red – New Pulverized Coal
Yellow – Natural Gas
Gray – Old Pulverized Coal

- Meets $CO_2$ goal: No

- Average cost of electricity in 2055: $46/MWh
- Cumulative cost of electricity over 50 years: $730 billion
- Production in 2055: 460 million MWh

**Figure 23: Aggressive renewable energy mandates with a .2 tons $CO_2$/MWh standard.**




**<u>Key to Model Printout</u>**

**Production by technology (top to bottom):**
Light blue – Wind
Dark blue – Nuclear
Yellow – Natural gas
Purple – Hydro
Dark Blue – IGCC w/ CCS
Gray – Old pulverized Coal
Black – Waste biomass
White – Dedicated Biomass IGCC

**Net $CO_2$ by technology (top to bottom):**
Yellow – Natural Gas
Green – IGCC w/ CCS
Gray – Old Pulverized Coal

- Meets $CO_2$ goal: Yes
- Average cost of electricity in 2055: $52/MWh
- Cumulative cost of electricity over 50 years: $743 billion
- Production in 2055: 436 million MWh

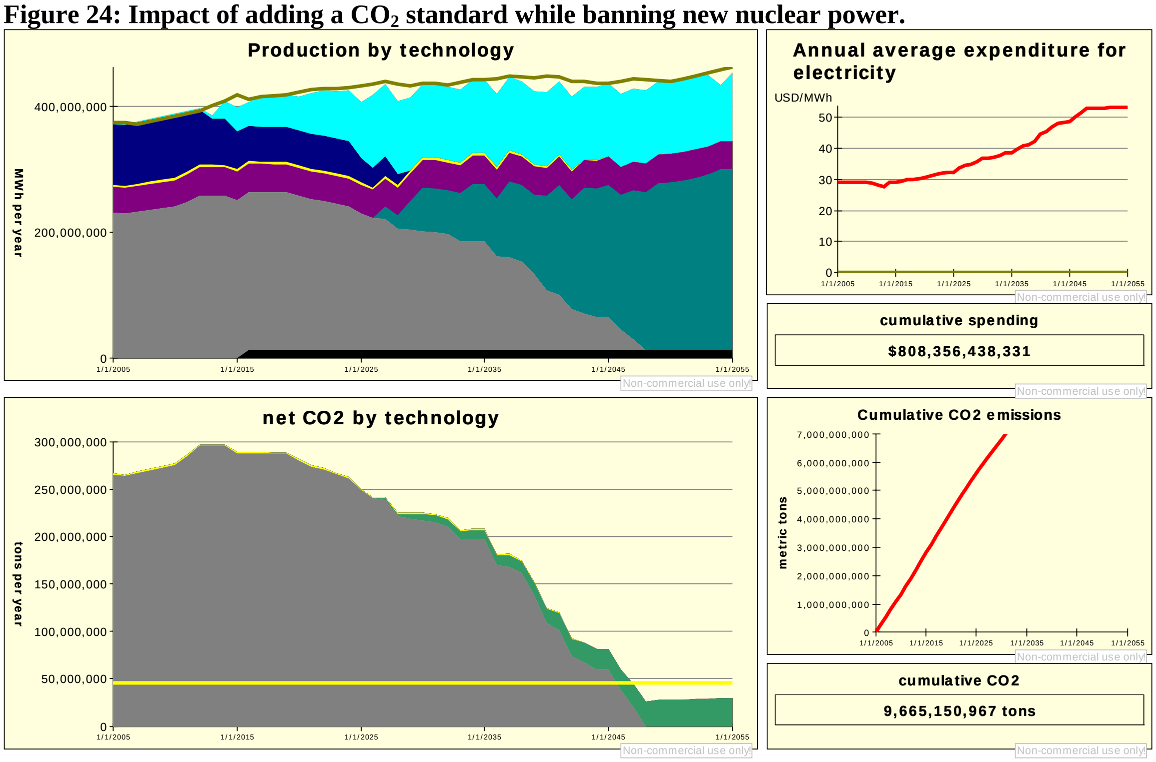
## G. High Coal Scenario

Production of electricity from coal with very low $CO_2$ emissions is possible, but in this model reduced carbon coal is a more expensive technology than other renewable energy technologies such as hydro, wind and nuclear. In the "tipping point" world of this model, IGCC with carbon capture and sequestration does not compete with those other carbon neutral technologies, and therefore does not appear at all without policy intervention.

Carbon neutral coal technology has the advantage, like nuclear, of providing base load electricity. Unlike wind, it can provide more than 20-30% of total net generation in the region. Since electricity from coal is currently the dominant technology in the region, there is no reason to think that this will be resource-limited.

In this scenario, the $CO_2$ standard is gradually phased in using the same assumptions as in the $CO_2$ standard scenario. The difference is that new nuclear power is banned.

**Figure 24: Impact of adding a $CO_2$ standard while banning new nuclear power.**




**<u>Key to model printout:</u>**

**Production by technology (top to bottom):**
Light blue – Wind
Dark blue – Nuclear
Yellow – Natural gas
Purple – Hydro
Dark Blue – IGCC w/ CCS
Gray – Old pulverized Coal
Black – Waste biomass

**Net $CO_2$ by technology (top to bottom):**
Yellow – Natural Gas
Green – IGCC w/ CCS
Gray – Old Pulverized Coal

**Results:**

- Meets $CO_2$ goal: Yes
- Average cost of electricity in 2055: $53/MWh
- Cumulative cost of electricity over 50 years: $808 billion
- Production in 2055: 454 million MWh

**Table 8: Summary of Scenarios**

| Scenario | BAU | High Efficiency - No $CO_2$ Standard | High Efficiency - $CO_2$ Standard | High Renewable - No $CO_2$ Standard | High Renewable - $CO_2$ Standard | High Coal | $CO_2$ Standard 2015 | $CO_2$ Tax 2015 |
|---|---|---|---|---|---|---|---|---|
| **Demand Management ($ million annually in the region)** | 96 | 500 | 500 | 96 | 96 | 96 | 96 | 96 |
| **Cost of Demand Management ($/MWh avoided)** | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| **CO2 Standard (tons $CO_2$/MWh)** | None | None | 0.2 | None | 0.2 | 0.2 | 1.2 in 2005, decreases by .2 every ten years | None |
| **CO2 Tax ($/ton $CO_2$ emitted)** | None | None | None | None | None | None | None | $0 in 2005, increases by $3/ton every ten years |
| **Maximum Technology Penetration** | | | | | | | | |
| ***Hydro*** | 7% | 7% | 7% | No max. | No max. | 7% | 7% | 7% |
| ***Wind*** | 25% | 25% | 25% | 30% | 30% | 25% | 25% | 25% |
| ***Nuclear*** | No max. | No max. | No max. | Forced to retire at end of life | Forced to retire at end of life | Forced to retire at end of life | No max. | No max. |
| ***Natural Gas*** | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% |
| **Minimum Technology Penetration** | | | | | | | | |
| ***Biomass IGCC*** | No min. | No min. | No min. | | | No min. | No min. | No min. |
| ***Wind*** | 8% | 8% | 8% | 30% | 30% | 8% | 8% | 8% |

| Scenario | BAU | | High Efficiency - No $CO_2$ Standard | | High Efficiency - $CO_2$ Standard | | High Renewable - No $CO_2$ Standard | | High Renewable - $CO_2$ Standard | | High Coal | | $CO_2$ Standard 2015 | | $CO_2$ Tax 2015 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Production Tax Credit** | Biomass, Biomass Waste, Wind, PV | | Biomass, Biomass Waste, Wind, PV | | Biomass, Biomass Waste, Wind, PV | | Biomass, Biomass Waste, Wind, PV | | Biomass, Biomass Waste, Wind, PV | | Biomass, Biomass Waste, Wind, PV | | Biomass, Biomass Waste, Wind, PV | | Biomass, Biomass Waste, Wind, PV | |
| **Achieves an 80% Reduction in $CO_2$?** | No | | No | | Yes | | No | | Yes | | Yes | | Yes | | Yes | |
| **$CO_2$ Emissions in 2055(million tons $CO_2$)** | 303 | | 267 | | 0 | | 167 | | 13 | | 30 | | 25 | | 2 | |
| **Cumulative 50 year CO2 emissions (billion tons $CO_2$)** | 14 | | 13 | | 9 | | 11 | | 9 | | 10 | | 10 | | 9 | |
| **Production in 2055(TWh)** | 521 | | 476 | | 447 | | 460 | | 436 | | 454 | | 490 | | 483 | |
| **Average Electricity Cost in 2055 ($/MWh)** | 42 | | 43 | | 49 | | 46 | | 52 | | 53 | | 48 | | 48 | |
| **Cumulative 50 Year Electricity Cost ($ Billion)** | 771 | | 721 | | 741 | | 730 | | 743 | | 808 | | 792 | | 811 | |
| **Production by Technology** | **TWh** | **Thousand MW** | **TWh** | **Thousand MW** | **TWh** | **Thousand MW** | **TWh** | **Thousand MW** | **TWh** | **Thousand MW** | **TWh** | **Thousand MW** | **TWh** | **Thousand MW** | **TWh** | **Thousand MW** |
| ***Biomass IGCC*** | 0 | 0 | 0 | 0 | 0 | 0 | 47 | 6 | 45 | 6 | 0 | 0 | 0 | 0 | 0 | 0 |
| ***Waste Biomass*** | 35 | 5 | 35 | 5 | 8 | 1 | 35 | 5 | 27 | 4 | 13 | 2 | 20 | 3 | 14 | 2 |
| ***IGCC w/ CCS*** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 131 | 18 | 288 | 39 | 0 | 0 | 0 | 0 |
| ***Hydro*** | 45 | 6 | 45 | 6 | 45 | 6 | 95 | 13 | 100 | 13 | 45 | 6 | 45 | 6 | 45 | 6 |
| ***Natural Gas*** | 4 | 1 | 4 | 1 | 0 | 0 | 4 | 1 | 0 | 0 | 0 | 0 | 27 | 4 | 4 | 1 |
| ***Nuclear*** | 107 | 14 | 107 | 14 | 282 | 38 | 0 | 0 | 0 | 0 | 0 | 0 | 254 | 34 | 299 | 40 |
| ***Wind*** | 43 | 12 | 37 | 11 | 112 | 32 | 137 | 39 | 133 | 38 | 109 | 31 | 128 | 37 | 121 | 35 |
| ***Pulverized Coal*** | 321 | 43 | 283 | 38 | 0 | 0 | 167 | 22 | 0 | 0 | 0 | 0 | 16 | 2 | 0 | 0 |

### H. Conclusions from the Scenario Analysis

- Implementation of a CO2 policy (standard or tax) as late as 2015 can still result in meeting the project goal by 2055, *assuming very little pulverized coal capacity comes on line before that date.* Because many pulverized coal plants are being planned right now, policy intervention will likely be required before 2015, at the very least to allow utilities to avoid sunk costs in planning plants. The sooner the policy is implemented, the sooner the goal is met. This research gives clear direction regarding the magnitude of a standard or tax and what impact it will have.
- Only the scenarios that imposed explicit CO2 policies met the study goal.
- Because pulverized coal plants are the cheapest technology with a significant resource (hydro is cheaper but resource constrained) it always becomes the dominant technology unless specific policies eliminate it. Very little pulverized coal electricity can exist while meeting the study goals.
- Old pulverized coal is the cheapest technology, because for the most part the capital expenditure in these plants is paid for. In all scenarios these plants are forced to retire at the end of their lives, but this may not occur in reality. These plants may continue on long after the 50 year timeframe states as an assumption of this study. The region will need to develop policies to assure that these plants eventually shut down, although they would not need to do so immediately in order to meet a 2055 goal. Keeping them running as long as possible may be a strategy for preventing the construction of new pulverized coal plants while other resources are being developed.
- Even with aggressive development of renewable energy, there will still be a need for a considerable amount of non-renewable base load electricity. The most likely candidates at present are nuclear and coal IGCC with capture and storage of CO2. Both of these options may have challenges from the perspective of social acceptance, but dealing with the CO2 problem as outlined in this report likely means coming to terms with one or both of these options.
- Wind is likely to be the dominant source of renewable energy due to economics and resource potential. Hydroelectric is resource constrained, but will expand as much as possible due to its favorable economics. Biomass is unlikely to be a significant source of electricity because of its unfavorable economics relative to wind and hydroelectric, unless it is favored by policy. The economics of biomass power may be improved by polygeneration of heat, fuels, and electricity, but that is not considered in this model.
- Demand reduction is the cheapest way to reduce CO2 emissions, although it has the seemingly unintuitive effect of increasing the average cost of electricity. This is because the utility spends some portion of its revenue on reducing demand, and this cost is spread among fewer units of power that are still produced. Although this increases the average cost of electricity, it decreases overall cumulative spending on electricity.
- Demand reduction in combination with policy intervention can result in cumulative costs that are actually cheaper than the Business as Usual scenario. This suggests that aggressive demand reduction could actually be used to pay for climate change mitigation.

## Recommendations for Further Study

The results of the study indicate that in order to achieve the emissions target, the electricity 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.
- Expand the model to include the transportation sector and use of natural gas for heat.
- Design a new interface for the model that allows tailored state-by-state scenarios. Possibly expand the model nation-wide for the U.S.
- 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 producing base load electricity from wind by combining wind with various storage strategies (batteries, hydrogen production with fuel cells, flow batteries, and compressed air)
- 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 alongside liquid fuels, natural gas, heat, and high-value chemicals.
- Thoroughly evaluate regional potential for terrestrial sequestration and evaluate its impact on the economics of producing biomass.
- Study the integration of the electricity sector with liquid fuels production to understand the benefits and trade-offs of producing liquid fuels from coal and biomass gasification, and hydrogen production.

## Appendix I: Summary of Emissions Inventory Methodology

The authors calculated total emissions for the 8 states in the region using EIA data from Forms 860, 920, and 906 in combination with methodology from the State Inventory Tool[62].

This appendix lists some of the emission factors used in the analysis. The emissions methodology was as follows. Authors started with EIA form data listing total consumption of coal, natural gas, and petroleum in the study region, delineated by state and sector. The EIA data set listed data from 1960-2001.

Authors, adopting the methodology from EPA's State Inventory Tool, first calculated what percentage of fuel consumption went to "non-fuel uses". This was primarily an issue for petroleum products. The authors used these numbers to subtract non-fuel use from emissions calculations.

[62] EPA's State Inventory Tool has been removed from the EPA's website since the authors performed their inventory. Information can be found at http://www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html

**Table 9: National non-energy consumption numbers. Data is listed in 5 year intervals to save space, while unique data was available for every year for purposes of this analysis.**

| Industrial Sector | 1960 | 1965 | 1970 | 1975 | 1980 | 1985 | 1990 | 1995 | 2000 | 2005 | Average of 1990-2000 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coking Coal | 3% | 3% | 3% | 3% | 3% | 3% | 2% | 3% | 3% | 3% | 3% |
| Natural Gas | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 5% | 4% | 4% |
| Asphalt and Road Oil | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| LPG | 71% | 71% | 71% | 71% | 71% | 71% | 69% | 72% | 74% | 71% | 71% |
| Lubricants | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Pentanes Plus | 64% | 64% | 64% | 64% | 64% | 64% | 30% | 83% | 84% | 64% | 64% |
| Feedstocks, Naphtha less than 401 F | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 92% |
| Feedstocks, Other Oils greater than 401 F | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 92% | 92% |
| Still Gas | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 3% | 1% | 1% | 1% |
| Petroleum Coke | 29% | 29% | 29% | 29% | 29% | 29% | 26% | 26% | 31% | 29% | 29% |
| Special Naphthas | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Distillate Fuel | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |
| Residual Fuel | 35% | 35% | 35% | 35% | 35% | 35% | 13% | 20% | 100% | 35% | 35% |
| Waxes | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Misc. Petro Products | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Other Coal | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Independent Power Coal | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Aviation Gasoline Blending Components | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Crude Oil | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Kerosene | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Motor Gasoline | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Motor Gasoline Blending Components | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Unfinished Oils | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Transportation** | | | | | | | **1990** | **1995** | **2000** | | |
| Lubricants | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

After subtracting non-energy consumption of fossil fuels, CO2 emissions were calculated using standard emissions coefficients. They are listed below.

**Table 10: Default Carbon Contents**

| Default Carbon Contents | | |
|---|---|---|
| Fuel | Metric tonnes/Bbtu | lbs carbon/Mbtu |
| Asphalt and Road Oil | 20.6199 | 45.45933 |
| Aviation Gasoline | 18.8699 | 41.60124 |
| Distillate Fuel | 19.9499 | 43.98223 |
| Jet Fuel, Kerosene | variable by year | variable by year |
| Jet Fuel, Naphtha | 19.73117 | 43.5 |
| Kerosene | 19.7199 | 43.47517 |
| LPG | variable by year | variable by year |
| Lubricants | 20.2399 | 44.62157 |
| Motor Gasoline | variable by year | variable by year |
| Residual Fuel | 21.48989 | 47.37735 |
| Misc. Petro Products | variable by year | variable by year |
| Feedstocks, Naphtha | 18.13991 | 39.99186 |
| Feedstocks, Other Oils | 19.9499 | 43.98223 |
| Pentanes Plus | 18.23991 | 40.21232 |
| Petroleum Coke | 27.84986 | 61.39875 |
| Still Gas | 17.50991 | 38.60295 |
| Special Naphthas | 19.8599 | 43.78381 |
| Unfinished Oils | variable by year | variable by year |
| Waxes | 19.8099 | 43.67358 |
| Residential Coal | variable by year | variable by year |
| Commercial Coal | variable by year | variable by year |
| Industrial Coking Coal | variable by year | variable by year |
| Industrial Other Coal | variable by year | variable by year |
| Independent Power Coal | variable by year | variable by year |
| Utility Coal | variable by year | variable by year |
| Natural Gas | 14.46993 | 31.90089 |
| Aviation Gasoline Blending Components | 18.86934 | 41.6 |
| Motor Gasoline Blending Components | variable by year | variable by year |
| Crude Oil | variable by year | variable by year |

**Table 11: Variable carbon coefficients. From the file "CO2 from Fossil Fuel Combustion 00.xls," stored with Inventory spreadsheets. Source: Carbon Content Coefficients" DOE/EIA, Perry Lindstrom, 202/586-0934, param01.xls, September 2001**

| Metric tonnes carbon/Bbtu | | | | | | |
|---|---|---|---|---|---|---|
| Fuel Type | 1960 | 1970 | 1980 | 1990 | 2000 | Average 1990-2000 |
| LPG | 16.98795 | 16.98795 | 16.98795 | 16.98821 | 16.98795 | 16.98795 |
| Motor Gasoline | 19.3399 | 19.3399 | 19.3399 | 19.4099 | 19.3399 | 19.3399 |
| Jet Fuel, Kerosene | 19.33107 | 19.33107 | 19.33107 | 19.40036 | 19.33107 | 19.33107 |
| Motor Gasoline Blending Components | 19.3399 | 19.3399 | 19.3399 | 19.4099 | 19.3399 | 19.3399 |
| Misc. Petro Products | 20.23237 | 20.23237 | 20.23237 | 20.15667 | 20.23237 | 20.23237 |
| Unfinished Oils | 20.23237 | 20.23237 | 20.23237 | 20.15667 | 20.23237 | 20.23237 |
| Crude Oil | 20.23237 | 20.23237 | 20.23237 | 20.15667 | 20.23237 | 20.23237 |
| | | | | | | |
| Ibs Carbon/million Btu | | | | | | |
| Fuel Type | 1960 | 1970 | 1980 | 1990 | 2000 | Average 1990-2000 |
| LPG | 37.45221 | 37.45221 | 37.45221 | 37.45278 | 37.45221 | 37.45221 |
| Motor Gasoline | 42.63741 | 42.63741 | 42.63741 | 42.79173 | 42.63741 | 42.63741 |
| Jet Fuel, Kerosene | 42.61793 | 42.61793 | 42.61793 | 42.7707 | 42.61793 | 42.61793 |
| Motor Gasoline Blending Components | 42.63741 | 42.63741 | 42.63741 | 42.79173 | 42.63741 | 42.63741 |
| Misc. Petro Products | 44.60497 | 44.60497 | 44.60497 | 44.43809 | 44.60497 | 44.60497 |
| Unfinished Oils | 44.60497 | 44.60497 | 44.60497 | 44.43809 | 44.60497 | 44.60497 |
| Crude Oil | 44.60497 | 44.60497 | 44.60497 | 44.43809 | 44.60497 | 44.60497 |

**Table 12 :Electric utility coal coefficients by state (Metric tonnes Carbon/Btu)**

| | 1960 | 1970 | 1980 | 1990 | 2000 | Average of 1990-1999 |
|---|---|---|---|---|---|---|
| IA Electric Utilities Coal CC | 26.00282 | 26.00282 | 26.00282 | 26.06493 | 26.00282 | 26.00282 |
| IL Electric Utilities Coal CC | 25.52579 | 25.52579 | 25.52579 | 25.43403 | 25.52579 | 25.52579 |
| MN Electric Utilities Coal CC | 26.17747 | 26.17747 | 26.17747 | 26.34946 | 26.17747 | 26.17747 |
| MT Electric Utilities Coal CC | 26.23567 | 26.23567 | 26.23567 | 26.41131 | 26.23567 | 26.23567 |
| ND Electric Utilities Coal CC | 26.9184 | 26.9184 | 26.9184 | 26.5845 | 26.9184 | 26.9184 |
| SD Electric Utilities Coal CC | 26.59488 | 26.59488 | 26.59488 | 27.05458 | 26.59488 | 26.59488 |
| US Electric Utilities Coal CC | 25.6332 | 25.6332 | 25.6332 | 25.68144 | 25.6332 | 25.6332 |
| WI Electric Utilities Coal CC | 25.90522 | 25.90522 | 25.90522 | 25.9536 | 25.90522 | 25.90522 |
| WY Electric Utilities Coal CC | 26.06924 | 26.06924 | 26.06924 | 26.22575 | 26.06924 | 26.06924 |
| GREAT PLAINS Electric Utilities Coal CC | 26.17869 | 26.17869 | 26.17869 | 26.25977 | 26.17869 | 26.17869 |
| IA Res + Comm Coal CC | 25.27765 | 25.27765 | 25.27765 | 25.24847 | 25.27765 | 25.27765 |
| IL Res + Comm Coal CC | 25.20357 | 25.20357 | 25.20357 | 25.17425 | 25.20357 | 25.20357 |
| MN Res + Comm Coal CC | 26.02491 | 26.02491 | 26.02491 | 26.22575 | 26.02491 | 26.02491 |
| MT Res + Comm Coal CC | 26.15162 | 26.15162 | 26.15162 | 26.18864 | 26.15162 | 26.15162 |
| ND Res + Comm Coal CC | 26.78214 | 26.78214 | 26.78214 | 26.9185 | 26.78214 | 26.78214 |
| SD Res + Comm Coal CC | 26.2135 | 26.2135 | 26.2135 | 26.17627 | 26.2135 | 26.2135 |
| US Res + Comm Coal CC | 25.96658 | 25.96658 | 25.96658 | 25.91648 | 25.96658 | 25.96658 |
| WI Res + Comm Coal CC | 25.43417 | 25.43417 | 25.43417 | 26.20101 | 25.43417 | 25.43417 |
| WY Res + Comm Coal CC | 26.32601 | 26.32601 | 26.32601 | 26.31234 | 26.32601 | 26.32601 |
| GREAT PLAINS Res + Comm Coal CC | 25.92669 | 25.92669 | 25.92669 | 26.05565 | 25.92669 | 25.92669 |
| IA Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| IL Coking Coal CC | 25.54882 | 25.54882 | 25.54882 | 25.45877 | 25.54882 | 25.54882 |
| MN Coking Coal CC | 25.54882 | 25.54882 | 25.54882 | 25.45877 | 25.54882 | 25.54882 |
| MT Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| ND Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| SD Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| US Coking Coal CC | 25.53308 | 25.53308 | 25.53308 | 25.50825 | 25.53308 | 25.53308 |
| WI Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| WY Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| GREAT PLAINS Coking Coal CC | 25.54882 | 25.54882 | 25.54882 | 25.45877 | 25.54882 | 25.54882 |
| IA Other Coal CC | 25.63278 | 25.63278 | 25.63278 | 25.3598 | 25.63278 | 25.63278 |
| IL Other Coal CC | 25.25382 | 25.25382 | 25.25382 | 25.22373 | 25.25382 | 25.25382 |
| MN Other Coal CC | 26.11646 | 26.11646 | 26.11646 | 26.17627 | 26.11646 | 26.11646 |
| MT Other Coal CC | 26.34388 | 26.34388 | 26.34388 | 26.18864 | 26.34388 | 26.34388 |
| ND Other Coal CC | 27.01197 | 27.01197 | 27.01197 | 27.0051 | 27.01197 | 27.01197 |
| SD Other Coal CC | 26.22911 | 26.22911 | 26.22911 | 26.31234 | 26.22911 | 26.22911 |
| US Other Coal CC | 25.61076 | 25.61076 | 25.61076 | 25.58248 | 25.61076 | 25.61076 |
| WI Other Coal CC | 25.52447 | 25.52447 | 25.52447 | 25.49588 | 25.52447 | 25.52447 |
| WY Other Coal CC | 26.28303 | 26.28303 | 26.28303 | 26.25049 | 26.28303 | 26.28303 |
| GREAT PLAINS Other Coal CC | 26.04944 | 26.04944 | 26.04944 | 26.00153 | 26.04944 | 26.04944 |
| IA Total Consumption of All Sectors Coal CC | 25.96958 | 25.96958 | 25.96958 | 25.94122 | 25.96958 | 25.96958 |
| IL Total Consumption of All Sectors Coal CC | 25.49189 | 25.49189 | 25.49189 | 25.40929 | 25.49189 | 25.49189 |
| MN Total Consumption of All Sectors Coal CC | 26.20815 | 26.20815 | 26.20815 | 26.33708 | 26.20815 | 26.20815 |
| MT Total Consumption of All Sectors Coal CC | 26.33898 | 26.33898 | 26.33898 | 26.41131 | 26.33898 | 26.33898 |
| ND Total Consumption of All Sectors Coal CC | 27.02433 | 27.02433 | 27.02433 | 27.04221 | 27.02433 | 27.02433 |

| | | | | | | |
|---|---|---|---|---|---|---|
| SD Total Consumption of All Sectors Coal CC | 26.57671 | 26.57671 | 26.57671 | 26.96799 | 26.57671 | 26.57671 |
| US Total Consumption of All Sectors Coal CC | 25.65216 | 25.65216 | 25.65216 | 25.6567 | 25.65216 | 25.65216 |
| WI Total Consumption of All Sectors Coal CC | 25.86951 | 25.86951 | 25.86951 | 25.90411 | 25.86951 | 25.86951 |
| WY Total Consumption of All Sectors Coal CC | 26.16248 | 26.16248 | 26.16248 | 26.22575 | 26.16248 | 26.16248 |
| GREAT PLAINS Total Consumption of All Sectors Coal CC | 26.2052 | 26.2052 | 26.2052 | 26.27987 | 26.2052 | 26.2052 |

**Table 13 :Electric utility coal coefficients by state (lbs Carbon/million Btu)**

| | 1960 | 1970 | 1980 | 1990 | 2000 | Average of 1990-1999 |
|---|---|---|---|---|---|---|
| IA Electric Utilities Coal CC | 57.3267 | 57.3267 | 57.3267 | 57.46364 | 57.3267 | 57.3267 |
| IL Electric Utilities Coal CC | 56.27503 | 56.27503 | 56.27503 | 56.07273 | 56.27503 | 56.27503 |
| MN Electric Utilities Coal CC | 57.71175 | 57.71175 | 57.71175 | 58.09091 | 57.71175 | 57.71175 |
| MT Electric Utilities Coal CC | 57.84005 | 57.84005 | 57.84005 | 58.22727 | 57.84005 | 57.84005 |
| ND Electric Utilities Coal CC | 59.34523 | 59.34523 | 59.34523 | 58.60909 | 59.34523 | 59.34523 |
| SD Electric Utilities Coal CC | 58.63197 | 58.63197 | 58.63197 | 59.64545 | 58.63197 | 58.63197 |
| US Electric Utilities Coal CC | 56.51182 | 56.51182 | 56.51182 | 56.61818 | 56.51182 | 56.51182 |
| WI Electric Utilities Coal CC | 57.11153 | 57.11153 | 57.11153 | 57.21818 | 57.11153 | 57.11153 |
| WY Electric Utilities Coal CC | 57.47313 | 57.47313 | 57.47313 | 57.81818 | 57.47313 | 57.47313 |
| GREAT PLAINS Electric Utilities Coal CC | 57.71442 | 57.71442 | 57.71442 | 57.89318 | 57.71442 | 57.71442 |
| IA Res + Comm Coal CC | 55.72798 | 55.72798 | 55.72798 | 55.66364 | 55.72798 | 55.72798 |
| IL Res + Comm Coal CC | 55.56464 | 55.56464 | 55.56464 | 55.5 | 55.56464 | 55.56464 |
| MN Res + Comm Coal CC | 57.3754 | 57.3754 | 57.3754 | 57.81818 | 57.3754 | 57.3754 |
| MT Res + Comm Coal CC | 57.65475 | 57.65475 | 57.65475 | 57.73636 | 57.65475 | 57.65475 |
| ND Res + Comm Coal CC | 59.04482 | 59.04482 | 59.04482 | 59.34545 | 59.04482 | 59.04482 |
| SD Res + Comm Coal CC | 57.79117 | 57.79117 | 57.79117 | 57.70909 | 57.79117 | 57.79117 |
| US Res + Comm Coal CC | 57.24682 | 57.24682 | 57.24682 | 57.13636 | 57.24682 | 57.24682 |
| WI Res + Comm Coal CC | 56.07303 | 56.07303 | 56.07303 | 57.76364 | 56.07303 | 56.07303 |
| WY Res + Comm Coal CC | 58.03922 | 58.03922 | 58.03922 | 58.00909 | 58.03922 | 58.03922 |
| GREAT PLAINS Res + Comm Coal CC | 57.15888 | 57.15888 | 57.15888 | 57.44318 | 57.15888 | 57.15888 |
| IA Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| IL Coking Coal CC | 56.3258 | 56.3258 | 56.3258 | 56.12727 | 56.3258 | 56.3258 |
| MN Coking Coal CC | 56.3258 | 56.3258 | 56.3258 | 56.12727 | 56.3258 | 56.3258 |
| MT Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| ND Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| SD Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| US Coking Coal CC | 56.29111 | 56.29111 | 56.29111 | 56.23636 | 56.29111 | 56.29111 |
| WI Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| WY Coking Coal CC | 0 | 0 | 0 | 0 | 0 | 0 |
| GREAT PLAINS Coking Coal CC | 56.3258 | 56.3258 | 56.3258 | 56.12727 | 56.3258 | 56.3258 |
| IA Other Coal CC | 56.51091 | 56.51091 | 56.51091 | 55.90909 | 56.51091 | 56.51091 |
| IL Other Coal CC | 55.67544 | 55.67544 | 55.67544 | 55.60909 | 55.67544 | 55.67544 |
| MN Other Coal CC | 57.57723 | 57.57723 | 57.57723 | 57.70909 | 57.57723 | 57.57723 |
| MT Other Coal CC | 58.07862 | 58.07862 | 58.07862 | 57.73636 | 58.07862 | 58.07862 |
| ND Other Coal CC | 59.55152 | 59.55152 | 59.55152 | 59.53636 | 59.55152 | 59.55152 |
| SD Other Coal CC | 57.82559 | 57.82559 | 57.82559 | 58.00909 | 57.82559 | 57.82559 |
| US Other Coal CC | 56.46236 | 56.46236 | 56.46236 | 56.4 | 56.46236 | 56.46236 |
| WI Other Coal CC | 56.27212 | 56.27212 | 56.27212 | 56.20909 | 56.27212 | 56.27212 |

| | | | | | | |
|---|---|---|---|---|---|---|
| WY Other Coal CC | 57.94448 | 57.94448 | 57.94448 | 57.87273 | 57.94448 | 57.94448 |
| GREAT PLAINS Other Coal CC | 57.42949 | 57.42949 | 57.42949 | 57.32386 | 57.42949 | 57.42949 |
| IA Total Consumption of All Sectors Coal CC | 57.25342 | 57.25342 | 57.25342 | 57.19091 | 57.25342 | 57.25342 |
| IL Total Consumption of All Sectors Coal CC | 56.2003 | 56.2003 | 56.2003 | 56.01818 | 56.2003 | 56.2003 |
| MN Total Consumption of All Sectors Coal CC | 57.77938 | 57.77938 | 57.77938 | 58.06364 | 57.77938 | 57.77938 |
| MT Total Consumption of All Sectors Coal CC | 58.06781 | 58.06781 | 58.06781 | 58.22727 | 58.06781 | 58.06781 |
| ND Total Consumption of All Sectors Coal CC | 59.57877 | 59.57877 | 59.57877 | 59.61818 | 59.57877 | 59.57877 |
| SD Total Consumption of All Sectors Coal CC | 58.59193 | 58.59193 | 58.59193 | 59.45455 | 58.59193 | 58.59193 |
| US Total Consumption of All Sectors Coal CC | 56.55363 | 56.55363 | 56.55363 | 56.56364 | 56.55363 | 56.55363 |
| WI Total Consumption of All Sectors Coal CC | 57.03281 | 57.03281 | 57.03281 | 57.10909 | 57.03281 | 57.03281 |
| WY Total Consumption of All Sectors Coal CC | 57.67869 | 57.67869 | 57.67869 | 57.81818 | 57.67869 | 57.67869 |
| GREAT PLAINS Total Consumption of All Sectors Coal CC | | | | | | |

Since EIA's data double counts synthetic natural gas production, synthetic natural gas was subtracted from industrial coal.

## Appendix II: Overview of simulation model

This report lays out a series of scenarios under which net CO2 production from Upper Midwest power generation can be reduced by 2055 to 20% of its 1990 levels. Underlying the report is a simulation model that tracks power generation and CO2 emissions over that time period, estimating cost and demand effects, and showing where and how necessary decisions might be made. This permits examination of economic conditions and policy decisions that are consistent with movement of the system to meet expected power demand and meet CO2 reduction goals.

The model runs in Powersim Studio 2005, a proprietary software system sold by Powersim Software AS. Powersim is a modern variant of the systems dynamics models first developed in the 1970s at the Massachusetts Institute of Technology. This appendix summarizes the rules and parameters that govern the operation of that simulation model. Current code is available from Steven J. Taff, sjtaff@umn.edu.

The software enables the developer to set transition and state rules by which a system of elements evolve, subject to parameter constraints. The model mimics plant-level decisions and calculates the power and pollution impacts of those decisions. Each year, plants with expiring permits are either closed or renewed, depending upon economic and regulatory conditions at that time. New plants employ the lowest cost technology anticipated at the time of the decision. Policies are set by a hypothetical region-wide governing body and apply to each state/province in the region. All policy scenarios (taxes, bans, mandates, subsidies, regulation) entered by the user are compared to a reference case with no special policies.

This is a "closed economy," a world in which all demand is met by production within the region. Consumers pay the total cost of production (except for non-internalized public expenditures), including all "economic profits." A useful result of the closed economy assumption is that the model can estimate CO2 emissions from all internal demand.

### Demand

Each year, demand is met by production sufficient to cover any increments in demand and non-renewals of existing plants. If a plant's license does not expire in a given year, it automatically continues production.

Demand is perfectly forecast by energy producers, so new plants are ready when they are needed. If a permit is not renewed, it takes a year for that plant's output to be replaced by new production capacity elsewhere. Demand is influenced by the economy (measured by changes in gross state product), by secular changes in the energy intensity of the economy (measured by power used per dollar of GSP), and by the elasticity of demand for power. Gross state product grows exponentially by a fixed real rate per state. Demand elasticity is constant and exogenous.

These parameters are used to measure both the change in quantity demanded due to a price change and to calculate the shift in the demand curve due to changes in non-price factors. At the beginning of the simulation, total first-year production is adjusted to correspond to total first-year demand levels for each state.

**Production**

The model analyzes policy effects on base load production: peak demand and associated production is not treated here. Demand is met first by continuing plants, then by renewed plants, and finally by new plants. Production always exactly equals demand at whatever price is necessary. All demand is satisfied. Power comes from in-state and other-state production: there are no imports and exports to and from the region.

If no policies to the contrary are in place, expiring plants are renewed automatically and new plants are built using the cheapest available technology, given resource (fuel) constraints. When a new plant is required to meet demand, it is built in the state and with the technology that provides the cheapest power to the consumer, taking into account transmission costs, subsidies and taxes, and permits.

Alternative technologies are evaluated by their levelized costs at the time of the decision. These costs include expected fuel and management costs, debt service, and payments to equity, as well as expected subsidies and taxes. Levelized costs are pre-income-tax and do not include distribution charges. Operation and maintenance costs include waste disposal and decommissioning expenses. Overnight capital costs include construction financing costs, brought forward to the year the plant begins operation.

If the cheapest technology happens to be a CO2 non-emitter, all new production will go to that technology in the default world, and so the default CO2 line will remain flat. If a permit is not renewed, the plant immediately ceases production and emissions.

Production origins are determined by cheapest source, but all production destinations are calculated fresh each year. Demand is met first by in-state plants. If total in-state production exceeds demand, the excess production is allocated to other states in proportion to their excess demands. Power price is the cost of obtaining power at the locus of demand. It includes full cost of production, net of subsidies and taxes, and distribution costs if the power is generated in another state. Distribution costs are assumed to be embedded in the cost of production for own-state sources.

**Parameters**

All initial prices, costs, demand, GSP, etc. magnitudes can be set by the user. We default to our best estimates of these numbers, drawn from a wide variety of technical sources. These settings have been extensively reviewed by outside parties.

Each state is a representative consumer, with its own annual demand and pricing structure. Plants are defined by their output size, their state, their technology, and the year in which their permits expire. Each state-technology-expiration pairing is a "plant," with its own annual production, emissions, and costs.

All physical production parameters are calculated from the output of each plant. From pre-set technical relationships (thermal efficiency, capacity factor, etc.) the model calculates necessary intervening variables such as installed capacity, fuel inputs, emissions, average costs, etc. Capacity is output divided by the capacity factor. Input is output divided by the thermal efficiency factor. Fuel use is output divided by the fuel use factor. These computations are performed separate for convenience: all these results are consistent one with the other.

There are no plant-level economies of scale or scope in this model. All cost growth is exponential. Inflation affects all production and fuel costs, but not policies. Thus, the effects of differential subsidies, for example, may wear off over time as the size of the subsidy diminishes relative to inflated costs. Fuel costs and operating expenses also grow at a specified real rate, over and above any inflation. Debt service is amortized overnight capital cost, determined over the life of the plant. Equity interest rates are separately calibrated. When an expiring plant is renewed it incurs anew the capital and operating costs that an identical new plant would face at the time of renewal.

Plant permit duration and plant engineering life are identical. The government can affect plant operation only when permits expire. There is no mid-permit intervention: the rules in place when the permit is granted are unchanged for the life of that plant.

IGCS technology costs include CO2 capture and injection charges, but they do not include transport costs to an offsite injection facility. All production and inject facilities are co-located. Production levels are constrained for some fuels in some states; notably biomass, water, photovoltaic, and wind. Fossil fuels and nuclear fuels are assumed to be shippable (even from outside the region) to any production location within the region, and their total reserves are assumed to far exceed any foreseeable demand. If current fuel use exceeds a constraint, then new plants cannot be created using this fuel type, nor can plants of this type be renewed.

Fuel volumes are short tons (for coal, biomass), barrels (for oil), and MCF (for gas). Solar, wind, and hydroelectric plants do not use "fuels" in the sense used here. Nuclear plant fuel costs are denominated in dollars per MWh output, not in dollars per unit volume.

**Policies**

The user can select any or all of several policy options.

**Technology portfolio standards**: New demand must first be served by production using the selected technology type, up to the selected proportion. The sum of target proportions must not exceed 1.0. New plants are built to meet a target as long as they don't exceed a resource constraint or violate an emissions standard.

**Ban technology**: When a plant comes up for renewal, it does not receive a permit. A technology can be banned, but a technology cannot be mandated absolutely. Even a technology portfolio standard might be limited by a resource constraint. If all technologies that meet a demand are banned, then there is no production. Demand is not met, and the model degenerates. If the region body mandates a technology that is at the same time banned, the mandate prevails.

**Subsidize/tax technology**: The cost for each unit of power produced is decremented (incremented) by the stated amount.

**Emissions standard**: When a plant comes up for renewal, it does not receive a permit if its emissions per power unit exceed the stated level. If all technologies that meet a demand are not permitted because of an emissions standard, then there is no production. Demand is not met, and the model degenerates.

**Emissions tax**: Any CO2 emissions (measured in volume) are taxed at the stated amount. The amount is added to the cost of production, to be borne by consumers of that plant's power. The tax, denominated in dollars per ton of CO2 emitted applies to all emissions in all states.

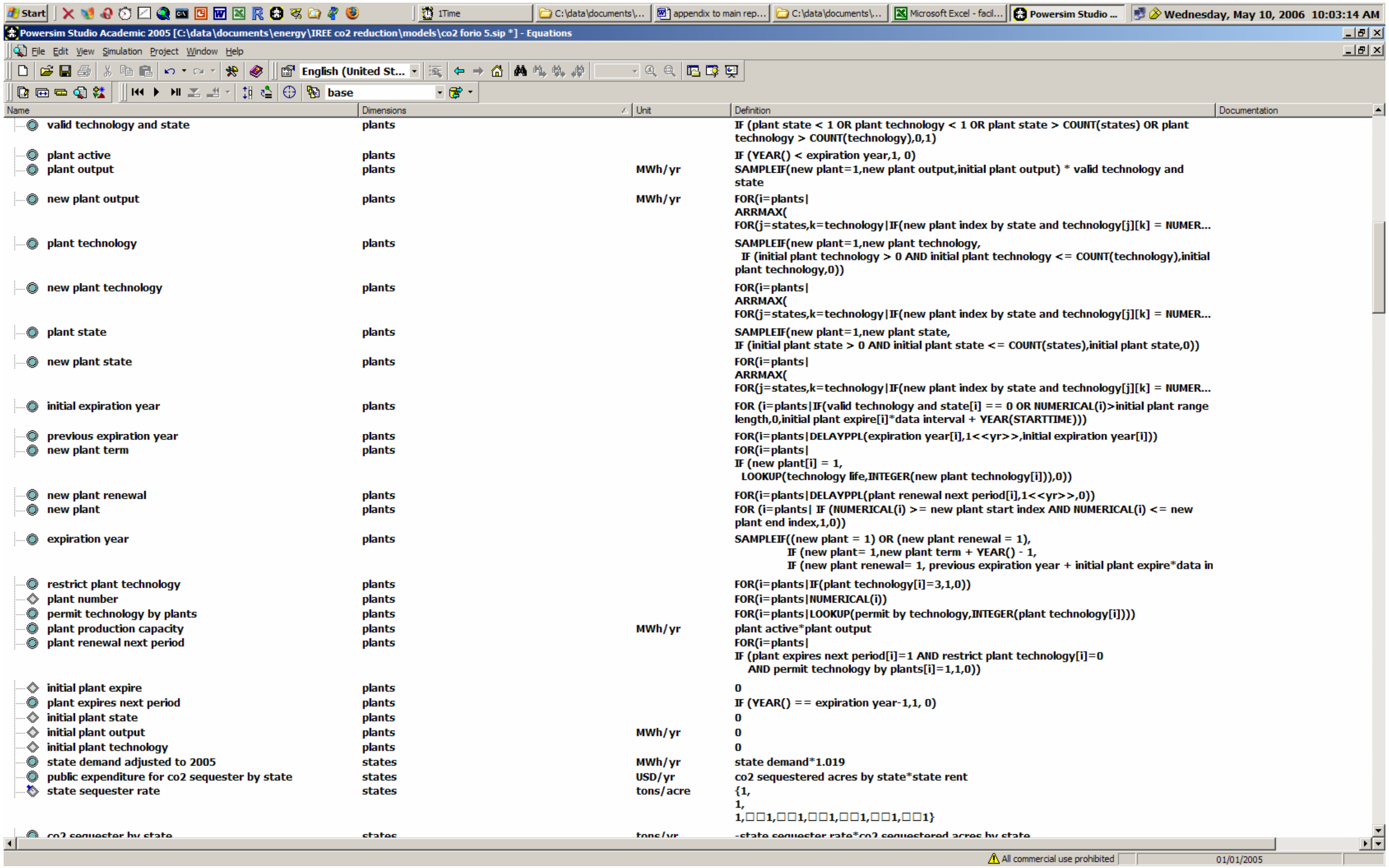
**Subsidize/tax power production**: The cost for each unit of power produced is decremented (incremented) by the stated amount.

**Demand management**: This can be thought of as an investment to reduce demand, either through technical or behavioral changes. The buy-down cost is set at a per power unit cost for the reduction to be effective. The marginal cost curve is liner: both the intercept and the slope can be set by the user. The buy-down can be thought of as a demand shifter, a change in the magnitude of demand for a given price—in contrast to the demand elasticity which influences the shape of the demand curve. The cost of the buy-down reflects the producers' avoided cost of production.

**CO2 sequestration**: The net amount of CO2 added to the atmosphere can be decremented through land sequestration or geologic sequestration. For the former, an annual budget (set by states) is applied to rent land and use a change from row-crop production to permanent vegetation as a "credit" against which to apply CO2 emissions in each state. For geologic sequestration (CSS coal technologies), we assume that injection locations are feasible both technically and financially.

The Internalize option assigns pubic expenditures, net of public revenues (from taxes), to a tax on power production. This switch has the effect of shifting the financial burden of CO2 reduction strategies from the taxpayer to the consumer, with resulting impacts on demand through the elasticity factor. If the costs are not internalized, public costs are also shown on the cost graph. In the base case, there are no special policy costs, so there is no public net expenditure.

**Figure 25: Sample model equations**



<table>
<tr><th>Name</th><th>Dimensions</th><th>Unit</th><th>Definition</th><th>Documentation</th></tr>
<tr><td>valid technology and state</td><td>plants</td><td></td><td>IF (plant state < 1 OR plant technology < 1 OR plant state > COUNT(states) OR plant technology > COUNT(technology),0,1)</td><td></td></tr>
<tr><td>plant active</td><td>plants</td><td></td><td>IF (YEAR() < expiration year,1, 0)</td><td></td></tr>
<tr><td>plant output</td><td>plants</td><td>MWh/yr</td><td>SAMPLEIF(new plant=1,new plant output,initial plant output) * valid technology and state</td><td></td></tr>
<tr><td>new plant output</td><td>plants</td><td>MWh/yr</td><td>FOR(i=plants|<br>ARRMAX(<br>FOR(j=states,k=technology|IF(new plant index by state and technology[j][k] = NUMER...</td><td></td></tr>
<tr><td>plant technology</td><td>plants</td><td></td><td>SAMPLEIF(new plant=1,new plant technology,<br>IF (initial plant technology > 0 AND initial plant technology <= COUNT(technology),initial plant technology,0))</td><td></td></tr>
<tr><td>new plant technology</td><td>plants</td><td></td><td>FOR(i=plants|<br>ARRMAX(<br>FOR(j=states,k=technology|IF(new plant index by state and technology[j][k] = NUMER...</td><td></td></tr>
<tr><td>plant state</td><td>plants</td><td></td><td>SAMPLEIF(new plant=1,new plant state,<br>IF (initial plant state > 0 AND initial plant state <= COUNT(states),initial plant state,0))</td><td></td></tr>
<tr><td>new plant state</td><td>plants</td><td></td><td>FOR(i=plants|<br>ARRMAX(<br>FOR(j=states,k=technology|IF(new plant index by state and technology[j][k] = NUMER...</td><td></td></tr>
<tr><td>initial expiration year</td><td>plants</td><td></td><td>FOR (i=plants|IF(valid technology and state[i] == 0 OR NUMERICAL(i)>initial plant range length,0,initial plant expire[i]*data interval + YEAR(STARTTIME)))</td><td></td></tr>
<tr><td>previous expiration year</td><td>plants</td><td></td><td>FOR(i=plants|DELAYPPL(expiration year[i],1<<yr>>,initial expiration year[i]))</td><td></td></tr>
<tr><td>new plant term</td><td>plants</td><td></td><td>FOR(i=plants|<br>IF (new plant[i] = 1,<br>LOOKUP(technology life,INTEGER(new plant technology[i])),0))</td><td></td></tr>
<tr><td>new plant renewal</td><td>plants</td><td></td><td>FOR(i=plants|DELAYPPL(plant renewal next period[i],1<<yr>>,0))</td><td></td></tr>
<tr><td>new plant</td><td>plants</td><td></td><td>FOR (i=plants| IF (NUMERICAL(i) >= new plant start index AND NUMERICAL(i) <= new plant end index,1,0))</td><td></td></tr>
<tr><td>expiration year</td><td>plants</td><td></td><td>SAMPLEIF((new plant = 1) OR (new plant renewal = 1),<br>IF (new plant= 1,new plant term + YEAR() - 1,<br>IF (new plant renewal= 1, previous expiration year + initial plant expire*data in</td><td></td></tr>
<tr><td>restrict plant technology</td><td>plants</td><td></td><td>FOR(i=plants|IF(plant technology[i]=3,1,0))</td><td></td></tr>
<tr><td>plant number</td><td>plants</td><td></td><td>FOR(i=plants|NUMERICAL(i))</td><td></td></tr>
<tr><td>permit technology by plants</td><td>plants</td><td></td><td>FOR(i=plants|LOOKUP(permit by technology,INTEGER(plant technology[i])))</td><td></td></tr>
<tr><td>plant production capacity</td><td>plants</td><td>MWh/yr</td><td>plant active*plant output</td><td></td></tr>
<tr><td>plant renewal next period</td><td>plants</td><td></td><td>FOR(i=plants|<br>IF (plant expires next period[i]=1 AND restrict plant technology[i]=0<br>AND permit technology by plants[i]=1,1,0))</td><td></td></tr>
<tr><td>initial plant expire</td><td>plants</td><td></td><td>0</td><td></td></tr>
<tr><td>plant expires next period</td><td>plants</td><td></td><td>IF (YEAR() == expiration year-1,1, 0)</td><td></td></tr>
<tr><td>initial plant state</td><td>plants</td><td></td><td>0</td><td></td></tr>
<tr><td>initial plant output</td><td>plants</td><td>MWh/yr</td><td>0</td><td></td></tr>
<tr><td>initial plant technology</td><td>plants</td><td></td><td>0</td><td></td></tr>
<tr><td>state demand adjusted to 2005</td><td>states</td><td>MWh/yr</td><td>state demand*1.019</td><td></td></tr>
<tr><td>public expenditure for co2 sequester by state</td><td>states</td><td>USD/yr</td><td>co2 sequestered acres by state*state rent</td><td></td></tr>
<tr><td>state sequester rate</td><td>states</td><td>tons/acre</td><td>{1,<br>1,<br>1,□□1,□□1,□□1,□□1,□□1,□□1}</td><td></td></tr>
<tr><td>co2 sequester by state</td><td>states</td><td>tons/yr</td><td>-state sequester rate*co2 sequestered acres by state</td><td></td></tr>
</table>

**Figure 26: Representative model parameter input**