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MINNESOTA ENERGY PLANNING REPORT

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CHAPTER ONE: MINNESOTA ENERGY TODAY

Energy is basic to most activities in our daily lives. We need energy to heat our homes in the winter, cool our homes in the summer, cook our meals, mow our lawns, heat our water, refrigerate and freeze our food, and wash and dry our clothes. When our housework is done, we need energy to provide light to read by, to power our televisions, stereos and computers, and to use our boats and other recreational vehicles. On the farm, energy powers the machines that till, plant and harvest our fields. In commerce, energy powers virtually all aspects of work, from the lighting and computers in our offices to the motors that run industrial and manufacturing processes, such as mining iron and processing ore into taconite, or harvesting wood and processing it into paper products. And when we move about, energy lights our highways and powers our vehicles and airplanes.

In 1999, Minnesotans consumed nearly 1,300 trillion British thermal units (Btus) of energy in the form of electricity, natural gas, and petroleum products.[1] Figure 1-1 shows the relative amounts of energy used by the commercial, residential, industrial and transportation sectors.

Figure 1-2 shows the types of fuel inputs used to produce this energy.[2] Our energy is produced and delivered to us by an extensive infrastructure that transports large amounts of fuel, such as oil, coal and natural gas, into the state for energy production, distribution and consumption. In 1999, Minnesotans spent approximately $9.7 billion to purchase the energy we used.

This chapter is divided into three sections that focus on electricity, natural gas and petroleum. Each section discusses trends in the use and cost of each source of energy, describes the infrastructure used to produce and deliver the energy to consumers and explains the regulatory structure for each energy source.

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[1] The Btu is the measurement of the heat content of energy, and is approximately equivalent to the heat produced by one wooden kitchen match.

[2] This figure does not include fuel used to generate the electricity purchased for Minnesota consumption for marketers or utilities without Minnesota service territory.

ELECTRICITY

This section presents information on the current use and cost of electricity in the state, as well as information on historical use and cost trends. It then describes the system currently in place to serve the electric demands of Minnesota homes and businesses. The section ends with a brief overview of the current electric regulatory structure and a background summary of the history of electric rate regulation.

Electricity Use and Cost in Minnesota

Minnesota homes and businesses consumed a total of 62,532,000 megawatt hours of electricity in 2000. Figure 1-3 shows the distribution of this electric consumption between commercial, residential and industrial customers. Many factors influence consumption, including weather, price, population levels and economic growth. Figure 1-4 illustrates that residential and commercial electric consumption have continued to steadily grow over the past 30 years. Industrial consumption has shown a greater rate of steady growth during the same time period. Overall, residential use of electricity has nearly doubled in 30 years. Despite conservation efforts, we are all using more electric appliances and electronic equipment. The use of air conditioners, computers, VCRs and electronic clocks on all our appliances and equipment has grown dramatically.

Weather is a major factor in residential usage. Figure 1-5 shows electric consumption per residential customer, after taking into account differences in weather from year to year. Adjusting for differences in weather is called “weather normalization,” and accounts for increased energy use in hotter summers or colder winters as well as decreased use during years of milder weather. Once weather factors are accounted for, residential usage shows a steady growth trend, with a steeper level of increase in the late 1990s.

In 1999, this level of usage resulted in Minnesotans spending approximately $3.4 billion on electricity. Figure 1-6 shows the historical trend in annual real expenditures on electricity in Minnesota by each major customer class, converted to 1999 dollars. Figure 1-7 shows the average electric prices in Minnesota for the non-farm residential, commercial and industrial customer classes. When converted to 1999 dollars, the real cost of electricity per kilowatt hour has declined fairly steadily since 1980. The latter part of the 1990s, however, shows a flattening of this trend line. One of the most significant factors affecting the price of electricity is the availability of generating capacity. As consumption increases and approaches or exceeds the level of available capacity, more capacity must be built, the cost of which will cause the price of electricity to increase.

For comparison, Figure 1-8 shows that Minnesota has historically enjoyed low electric prices relative to other parts of the country. Figure 1-8 shows that prices for all

Minnesota customer classes are significantly below the highest prices paid in the United States and that the price paid by residential and commercial customers is in the lower half of prices, while the price for industrial customers is 17th highest in the country. In all customer classes, the Minnesota price is much closer to the lowest price nationally than it is to the highest price.

System Description

A complex infrastructure, built up over several decades, provides the electricity used by Minnesotans. Minnesota's electric generation and delivery system, like any other, consists of three distinct parts: generation, transmission and distribution. An electric generating plant generates electricity by using different types of fuel turns a turbine that generates an electrical current. The fuel can be a commodity delivered to the plant, such as coal, natural gas and biomass, which are burned to turn water into steam which turns a turbine. A fuel also may be harvested directly from the environment at the location of the plant, such as wind and hydro power.

One of the most important concepts to understand when discussing electricity needs is the distinction between the term "megawatt" and the term "megawatt hours." A megawatt measures the total electric consumption or generation at a particular instant in time, which is known as the "demand" or "capacity" component of electricity. If Minnesota consumer demand totals 8,000 megawatts at any particular instant, that demand cannot be met unless there exists an equal number of megawatts of generating capacity on utility systems available for use by Minnesota consumers. Generating plants are often rated in terms of their size and ability to contribute to the electricity needs of the system by the greatest number of megawatts that can be generated at any particular point in time by the plant. Conversely, megawatt-hours measure electricity consumed or needed over time, which is often referred to as the "energy" component of electricity.[3] For example, the single peak hour of consumer demand in a year may be 8,000 megawatts, but in the course of the whole year, consumers may use 62,000,000 megawatt-hours of electric energy.

The electricity generated by an electric generating plant is then stepped-up in voltage and sent into the transmission system. The transmission system is designed to transport electricity at high voltage in as efficient a manner as possible to electric substations. The substations receive the high voltage power and, using transformers, step the voltage down so that it can be safely received by retail customers. The portion of the electric system by which power is delivered at stepped-down voltages to retail

[3] In this report, watts and watt-hours will generally be referred to with the prefix "mega," which designates a million watts or watt-hours. Other units that will be referred to in this report will be kilowatts and kilowatt-hours, which designates a thousand, and gigawatts and gigawatt-hours, which designates a billion.

customers is called the distribution system. Figure 1-9 provides a diagram of the basic components of an electric power system.

An electric generating, transmission and distribution system must have the capacity to meet the demand of consumers at peak times, normally measured in megawatts, as well as be capable of delivering throughout the year the number of megawatt-hours used by consumers.

In order to provide electric service at the lowest possible cost, electric utilities build a mix of baseload, intermediate, and peaking power plants in their systems. A baseload plant is designed to be in operation the majority of hours in the year, except for scheduled maintenance periods. An intermediate plant is operated less frequently at periods of higher demand or when baseload plants are not operating due to maintenance or repair needs. And, since the times of peak megawatt demand on the system occur only infrequently throughout a typical year, a utility will build a series of peaking plants that will be brought on line only when maximum demand is placed on the system.

The mix in generating plants reflects the nature of what is called the “load curve.” Figure 1-10 displays a daily load curve and annual load curve for two of Minnesota’s utility systems, Great River Energy (GRE) and Xcel Energy. The reason that utilities build different sorts of plants to meet this load is clear from the graph in Figure 1-10. There need to be enough baseload plants to meet the basic, ongoing need for electricity. At the same time, enough intermediate and peaking plants need to be available on the system in order to be called into service at the hours or days of highest use. For Xcel Energy and Great River Energy, and many other electric utilities in the state, the highest periods of peak demand occur during the summer air conditioning season on very hot days, particularly during the hours when people arrive home, turn up their air conditioning and start cooking supper. In areas of the state where natural gas service is not available and there is a greater reliance on electricity to heat homes, the electric peak can occur in the winter months as it does in the case of Minnesota Power and Otter Tail Power.

A proper mix of plants is crucial to providing low-cost power. Baseload generation plants are the most capital-intensive to build, but often have lower operating costs per unit of production. Because these plants are operated as much of the time as possible, the lower operating costs are beneficial to ratepayers. The converse is true for peaking generating plants which generally have lower capital costs than baseload plants, but, often due to the cost of the fuel that they burn, are more expensive to operate. Peaking plants, for example, are often fueled by natural gas or oil. Because these plants are operated for only a few hours or days during the year, it is more important for these plants to have lower capital costs, since the high operating costs are only incurred occasionally. As might be expected, intermediate plants are characterized by medium capital costs to construct and medium operating costs to operate. This is the best compromise for plants that will be operated frequently, but not constantly, to meet the electric needs of Minnesotans.

Figure 1-11 is a map that shows electric generating plants in Minnesota that are 100 megawatts or more in total capacity. As the symbols indicate, Minnesota's electric generating plants reflect several different technologies: coal, nuclear, natural gas, oil and wind. There are many other smaller generating plants, using a variety of different fuels and technologies, that work to produce electricity in Minnesota.[4]

The current Minnesota system is the result of decades of separate additions to the power system. Figure 1-12 illustrates the year when some of the largest generating units in the state began operation. A couple of significant peaking units, including two added this year, are included in red on the chart as well. Figure 1-12 illustrates the significant slowdown in baseload power plant construction activity over the last two decades.

While electric generating plants located in the state serve most of the need for electric power in the state, Minnesota also imports approximately 10 percent of its electrical power from sources outside the state. Figure 1-13 lists some plants in neighboring states, as well as in the Canadian province of Manitoba, that contribute some of the electrical energy they produce to serve the needs of Minnesotans. The location of these generating plants outside the borders of the state illustrate the interstate nature of the service areas of some of the utilities that serve Minnesota customers, as well as the fact that many municipal utilities and cooperative electric associations in the state receive their power from generation and transmission associations that own plants both inside and outside the borders of the state.

Figure 1-14 illustrates the relative percentage of fuels used to generate electricity that serves Minnesota. Coal and nuclear power plants predominate, accounting for 92 percent of all electric generation serving Minnesota.

Once power is produced at electric generating plants, utility companies must also build a system of transmission and distribution lines in order to deliver electric power to the retail customer. Figure 1-15 is a map of the largest, bulk transmission lines in Minnesota. The Minnesota transmission lines connect into an interstate system of transmission lines that will be further explained in chapter four. The key point is that all electric generating plants are connected to a transmission and distribution grid. The transmission grid requires a high level of interdependence among electric generators, and requires that the system be balanced between generation and customer demand

[4] This list can be found in Table 9 of the Utility Data Book, available on the Department of Commerce's website at www.commerce.state.mn.us/pages/Energy/Data/MainData.htm.

every second. The electrons generated by any particular generating plant move about the grid freely according to the rules of physics, not allowing for specific identification of electrons between a generation source and a source of consumption, and without regard to state or international borders.

The challenge of keeping the lights on at every moment in time requires a level of interdependent and coordinated operation in the electric industry that is not required of any other industry. The requirement that the power put into the transmission grid balance every second with the amount of power being taken off the grid also demands of the electric business an attention to situations on a minute by minute basis. By comparison, most industries and businesses utilize a short-term operational horizon of a month or a quarter of a calendar year.

There are two important reasons for creating an interdependent grid of generating plants and transmission lines to serve electric customers: the system is both cheaper and more reliable. As explained by one author:

> The early pioneers of the electric utility industry built individual systems, with no more than a handful of small plants matched to one small customer area. Between 1893 and 1898, the legendary utility magnate Samuel Insull found that the major economic implication of both short- and long-run interdependence … was that it was cheaper to connect all generators and all customers in one region, rather than trying to match one generator to a customer or customer group. The industry also quickly found out that interconnection and central control increased reliability dramatically.
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> Interconnection and central dispatch increase reliability by giving the operators of the grid more ability to adjust or restore the system after a failure. Because one operator has immediate control over most of the system, she can react to the situation with many possible responses, making it more likely that the outage can be minimized. A typical control center has control over dozens of power stations and hundreds of high-voltage lines, and it monitors virtually every plant and line in its area ….
>
> If this does not sound significant, consider this example. One utility, Union Electric, recently studied the amount of additional power plant capacity it would need to maintain reliable service if it was not interconnected to its neighboring

> utility. The answer was an additional 1,300 megawatts, 16 percent more generating plant than it requires when interconnected.[5]

Other chapters of the report will examine in detail current issues, potential for and barriers to deployment of various kinds of electric generating plants and will discuss the transmission system in greater detail.

To provide some perspective on the cost to build the current electric generation, transmission and distribution system, the Department calculated an approximate total cost of facilities that provide electric service for customers in Minnesota, based upon information filed with the Federal Energy Regulatory Commission by utilities serving Minnesota. The current electric system cost almost $13,000,000,000.[6] This figure reflects the book value of utility plant in dollars that have not been adjusted to reflect inflation despite the fact that many plants and lines were built twenty to fifty years ago. Therefore, particularly given the age of most plants and lines on the current system, the present value of the utility plant currently serving Minnesota would be significantly higher than this estimate.

Electric Regulatory Structure

Minnesota electric consumers are served by five rate-regulated investor-owned utilities, 46 cooperative electrical associations and 127 municipal utilities. The cooperative electric associations and municipal utilities often work with generation and transmission cooperative organizations and joint action agencies in order to coordinate the generation and transmission of power to the affected local municipal or cooperative utility, which handles distribution of the power to retail customers.[7] Figure 1-16 shows the percentage of Minnesota customers served by each type of utility company.

The regulatory structure differs for each of these types of utilities. The investor-owned utilities, Xcel Energy, Minnesota Power, Otter Tail Power, Alliant Energy and Northwestern Wisconsin, are regulated on the state level by the Public Utilities Commission. This state rate regulation has been in effect since 1974. Before 1974, the rates of these companies were regulated through local utility franchises. Cooperative electric associations are regulated by their membership, pursuant to the procedures established in State law for the functioning of these associations. Finally, municipal

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[5] Fox-Penner, Electric Utility Restructuring: A Guide to the Competitive Era, at 34 (1997).

[6] From FERC Form 1, submitted by Otter Tail Power Company, Interstate Power Company (now Alliant), Northern States Power Company (now Xcel Energy), Minnesota Power (now Allete), SMMPA, Great River Energy, Missouri River Energy, Dakota Electric Association and Minnkota Power Cooperative.

[7] A complete listing of these organizations can be found in the Department's Energy Policy and Conservation Report 2000, at pages 20 to 21. This publication is available on the Department's website at www.commerce.state.mn.us/pages/Energy/MainEnergyPolicy.htm.

utilities are operated by the municipal governments that own them, and those governments are responsible to the local electorate.[8]

Rate regulation was established for electric utilities in almost every state in the early part of the 1900s. Rate regulation was a response to the situation in the early 1900s where many small electric light companies served urban centers, with their own individual systems for generation, transmission and distribution of power. At that point, economic theory suggested that electric utilities were “natural monopolies.” The theory of natural monopoly is that a single, regulated provider can provide service to an area at the lowest total cost to customers. This lower cost was largely due to the elimination of redundant infrastructure, such as multiple transmission and distribution systems, as well as the economic phenomenon of large electric power plants providing lower average cost per unit of production than small ones (thus giving ratepayers the benefit of “economies of scale”).

Out of this policy choice, the current concept of rate regulation in place in Minnesota and many other states was born. Under the system of rate regulation, the state awards exclusive service territories to various utility companies, and then requires those companies to provide adequate and non-discriminatory service to all persons and companies in the service territory, with the rates charged to customers regulated by public entities. Rates are required to be set at a level that provides the utility, under prudent cost management, to recover its costs of providing retail electric service, as well as a reasonable return on the investment made by utility company shareholders in utility plant. Figure 1-17 shows a map of current electric utility service areas in the state of Minnesota.

When the Public Utilities Commission evaluates a request for a change in rates, it does so through a type of proceeding called a “general rate case.” A general rate case is usually initiated by a rate-regulated utility when it seeks to increase rates for its customers. The rate case provides a means for state regulators and any other interested group to thoroughly examine the expenses, revenues and expected rate of return to shareholders of public utilities and advocate various positions before the Public Utilities Commission prior to a final decision that sets the rates for the upcoming period.

A general rate case consists of two parts. First, a general rate case decides what is called the “revenue requirement” for the utility, which answers the question: “how much do we pay in total to the utility?” The revenue requirement is determined by selecting a representative year of operation of the company, evaluating the expenses of the

[8] There are procedures by which both municipal utilities and cooperative electric association customers may elect to become subject to rate regulation by the Public Utilities Commission. Only one electric cooperative association, Dakota Electric Association, has done so.

company (including a return on shareholder investment)[9] and the expected revenues, and subtracting expenses from revenues to determine whether there is a surplus or deficit for the utility company. If a surplus is found, then a refund will be provided to customers and lower rates will be established for future years. If a deficit is found, then rates are increased. Once the revenue requirement (or "how much we should pay") is established, the Public Utilities Commission evaluates the cost of serving the various kinds of customer classes of the utility, such as residential, farm, commercial, industrial and municipal lighting, and determines the rate that can be charged each type of electric consumer.[10]

The general rate case is a mechanism by which a utility's rates are periodically evaluated to be sure that they are reasonable and allow the utility's shareholders the opportunity to receive a reasonable return on their investment. In a rate case, a utility always has some expenses that have increased since the prior rate case and some expenses that have decreased. The rate case is a balancing where all of these expenses are properly evaluated and combined to determine whether the utility is under- or over-earning in total. The utility then moves forward from the general rate case with the incentive to manage its expenses in the best possible way to earn a greater return for shareholders. Investment decisions and other expenses incurred by the utility, if sought to be included in the next set of rates established, must be found to be reasonable and prudent expenditures by the Public Utilities Commission. This provides the context in which utility company managers are required to evaluate business risk in much the same way as managers of industries that are not rate regulated. The general rate case preserves some risk element for utility managers as well as incentive to control expenditures in prudent ways to avoid needing to apply for another rate increase.

History of Regulation of Electric Utilities

Although the system of retail utility rate regulation for investor-owned utilities continues to be in place in Minnesota today, it is helpful to review some of the significant developments in the electric utility industry that have affected the structure of rate regulation, as well as major federal acts that have impacted how electric utility service is provided and regulated in the United States.

There were major problems in establishing the system of rate regulation of electric utilities that resulted in some significant federal acts in the early part of the last century. For example, as electric companies grew, several firms created massive holding companies and acquired numerous local power companies. By the late 1920s, 60 percent of the electric power generated in the United States was controlled by seven

[9] The return on investment allowed is determined by multiplying a percentage of profit (rate of return) by the total undepreciated value of utility plant serving the customers (the "rate base").
[10] This part of a rate case is called "rate design."

holding company entities. The complexity of the holding company structures began to defeat the efforts of state regulators to track company expenses and revenues and properly regulate the rates. Interstate wholesale transactions between companies within a holding company and between holding companies were also found to be outside the jurisdiction of state commissions by the United States Supreme Court.

Congress responded in 1935 by passing the Public Utilities Holding Company Act (PUHCA) and the Federal Power Act (FPA). PUHCA created restrictions on the corporate structure of electric companies that curbed many of the holding company abuses documented from the 1920s. Additionally, the FPA established a system where retail electric rates would be regulated by state governments and wholesale electric transactions between utilities would be regulated by a new federal independent regulatory commission originally called the Federal Power Commission, now known as the Federal Energy Regulatory Commission (FERC).

Another problem that had become apparent by the 1930s was that electric utility companies did not view rural areas as good opportunities for investment, given the amount of transmission and distribution lines that would be required to serve a population density much lower than found in urban areas. As a result, rural citizens did not have access to electric service. Congress acted to encourage the electrification of rural America by passing a law that encouraged the development of rural cooperative electric associations to provide electricity to more sparsely populated areas of the United States.

With the protections provided by PUHCA, the clarifications of the Federal-State regulatory structure provided by the FPA, and the boost to rural electrification, a period of nearly 50 years passed without significant change in the legal structure affecting the electric utility industry. It is not surprising that the structure was not changed during this time, because, as described by one author:

> For decades following the onset of regulation, electric utilities experienced large, steady sales growth and declining prices. ... Between 1925 and 1970, the industry quadrupled the number of customers, but increased plant capacity 13 fold and sales by a factor of 25. ... Between 1906 and 1970, the average price of power to residences declined from 10 cents per kilowatt-hour to about 2.6 cents-*even before adjustment for inflation*. Of course, declining costs and prices as output increases are just what the theory of natural monopoly predicts...[11]

[11] Fox-Penner, at 12 and 14.

During this period, utilities found that building ever-larger power plants decreased the cost of electricity per kilowatt-hour sold to customers, due to the efficiencies of large-scale generation of electric power.

In the decade of the 1970s, however, the equation changed completely. Inflation and oil price shocks raised interest rates to high levels, while at the same time the price of fuels used in power plants skyrocketed. Dawning awareness of the cumulative environmental effects of emissions from large electric power plants lead to the onset of environmental requirements to put costly pollution control equipment into new electric power plants. By the 1970s, utilities also started to find that further increases in the size of electric power plants no longer achieved the expected economies of scale. Finally, the increase in energy costs prompted consumers to begin serious efforts to reduce their use of electricity. As described by one author:

> Utilities, which had seen steady rapid growth of demand throughout the first half of the century, built for a continuation of that level of demand growth. Plants grew larger and larger. It is certain that the oil crisis of the early 1970s forced fuel prices up, causing reductions in demand. Reduced demand left utilities with excess capacity. Customers had to pay for that excess. For the first time in history, electricity prices began to rise. Many public utility commissions would not allow utilities to recover the cost of building excess capacity from their consumers.[12]

With the development of more efficient small combustion units and alternative technologies, it was no longer necessarily the case that the large central utility coal or nuclear plant was the most cost-effective way to produce electricity.

Concern over the rising cost of electricity and the changing economies of scale of electric production lead Congress to pass the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA encouraged alternative generation resources from renewable energy technologies and co-generation. These small-scale methods of electric generation were called "qualifying facilities," and utilities were required to buy the electricity that these facilities generated at a rate equal to the cost that would be avoided by not constructing additional utility electric plants. PURPA's implementation encouraged electric production by non-utility generators.

Fifteen years later, Congress passed the Energy Policy Act of 1992 (EPAct) to further develop a market-competitive wholesale electric industry. EPAct also allowed the FERC to require utilities to allow wholesale producers of electricity to transmit their

[12] Congressman Bingaman, White Paper on Electricity Legislation, at 4 (July 20, 2001).

electricity along utility transmission lines for wholesale sale. PURPA and EPAct spurred the growth of non-utility generation facilities, called Independent Power Producers (IPPs), that contract with utilities to provide part of the generation resources needed to serve retail customers, as well as an increasingly market-based wholesale electricity market. In 2000, nonutility power producers produced 21 percent of the electricity in the United States.[13]

In Minnesota, as well as several other states, the last 20 years have seen the birth of several specific kinds of regulatory proceedings designed to address the issues of concern that started to emerge in the electric industry in the 1970s. For example, the Minnesota legislature created the integrated resource planning process that requires utilities to present to the MPUC, for public review and MPUC approval, their plan for meeting the electric needs in their service area in Minnesota over the next 15 year period. If the utility obtains approval of its resource plan, and acts in accordance with it, its decisions are substantially less subject to negative review in the utility's next general rate case or certificate of need[14] proceeding.

An increased awareness of the importance of conservation both to control an individual customer's utility bills, as well as to avoid the cost of new construction of electric generating facilities (which raises everyone's rates), lead to the establishment of the conservation improvement program (CIP). CIP requires state-regulated utilities to spend a specified percentage of gross operating revenues on efforts to conserve energy in their service area, and to submit to the Commissioner of Commerce their conservation plans for review and approval.

Finally, the legislature required that environmental costs begin to be factored into utility resource planning decisions the environmental impact of electric generation. During this same period, the Minnesota legislature added to certificate of need proceedings criteria that focused on alternatives to meet energy needs, assessed whether conservation efforts could avoid part of the need to build a new plant, and assured a full evaluation of renewable sources of energy before a certificate of need is issued for the construction of a non-renewable generation facility.

These proceedings provide more up-front oversight of significant capital investment decisions by utilities. They also provide the utilities with some assurance that the decisions will not be disallowed for recovery in their next general rate case. They reduce the risk of non-recovery for utilities in exchange for more public input into their major investment decisions.

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[13] Annual Energy Review 2000, EIA at 220.
[14] A certificate of need issued by the MPUC is statutorily required for large energy facilities. the proceeding determines whether a facility is needed before construction or whether there are more preferred ways of meeting potential demand.

NATURAL GAS

Sixty-three percent of Minnesota consumers have access to natural gas in their homes. Natural gas utility service is provided by three types of local distribution companies (LDCs): six rate-regulated investor-owned utilities, 18 municipal utilities, and seven private gas companies.[15] The investor-owned utilities provide natural gas service to 95 percent of natural gas customers in the state.

Minnesota contains no native sources of natural gas. Minnesota utilities obtain natural gas predominantly from natural gas fields in Kansas, Oklahoma, Texas and Alberta, Canada. The natural gas is delivered to the state through interstate pipelines, for distribution to end-use customers. The Northern Natural Gas pipeline transports 90 percent of the natural gas used in Minnesota from gas fields in the south-central United States. The Viking and Great Lakes transmission lines bring 7 percent and 3 percent of the natural gas to Minnesota, respectively, from Alberta, Canada.

Natural gas LDCs purchase gas from producers, contract with interstate pipelines to transport the gas to Minnesota, and construct and operate the distribution system that provides natural gas to the end-use customer. Figure 1-18 is a map of the natural gas pipelines in Minnesota, and Figure 1-19 is a diagram of the natural gas delivery system.

Use and Cost of Natural Gas in Minnesota

Minnesotans consumed a total of 352 million cubic feet (Mcf) of natural gas in 2000. Figure 1-20 shows the current consumption by residential, commercial, industrial and electric generation use in the state. Figure 1-21 shows the trends in natural gas consumption by sector and in total in Minnesota from 1970 to 2000. This graph shows relatively steady gas usage in the residential and commercial sectors, with a moderately increasing usage trend in the industrial sector. After a substantial overall drop during the 1970s and 1980s, usage is back to the early 1970s level. The use of natural gas for electric generation was curtailed during the decade of the 1970s, but is now being utilized more often, particularly in other states. The Minnesota chart will soon show some increase in this sector of natural gas consumption due to the opening of two natural gas peaking plants in the state in 2001.

Because natural gas is so widely used for space heating, it is difficult to talk about usage trends without adjusting for the impact of the relative warmth or coldness of our winters. Figure 1-22 shows the weather normalized natural gas consumption for residential customers in Minnesota, and reveals a steep decline in use of natural gas

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[15] A list of the various companies that provide gas utility service in the state can be found in the Department's Energy Policy and Conservation Report 2000, at page 21. This report is available on the Department's website at www.commerce.state.mn.us/pages/Energy/MainEnergyPolicy.htm.

between 1970 and 1985 when natural gas prices were last high, with very little change in consumption since 1985.

In 1999, Minnesotans spent approximately $1.37 billion on natural gas. Figure 1-23 shows the trend in real expenditures on natural gas in Minnesota by customer class over the last 30 years in 1999 dollars. Figure 1-24 shows natural gas prices over the last 30 years for the various customer classes in 1999 dollars.

Figure 1-25 displays the relationship of Minnesota price to average U.S. price and in the range high and lowest U.S. price for the year 1999. In relation to the rest of the country, Minnesota continues to experience lower than average prices in natural gas even during the record breaking high prices during the 2000-2001 heating season, as discussed below. One reason for this situation is Minnesota's strategic location between the Canadian and the southern U.S. natural gas production areas, with interstate pipelines bringing natural gas to the state from both areas.

Regulatory Structure

In the United States, individual states regulate local distribution companies (LDCs) who purchase natural gas from unregulated gas producers on an open market and pay to transport the gas through an open grid-system of federally regulated interstate pipelines to the ultimate retail customer.

In Minnesota, LDCs are rate-regulated by the Public Utilities Commission (MPUC). The MPUC approves the portion of the rate the LDC may charge for receiving natural gas from the interstate pipeline and distributing it to end-use customers, and for its operations, maintenance and customer service functions. The bulk of the cost of natural gas utility service is, however, the price of the delivered fuel, natural gas. LDCs purchase natural gas under a variety of short-term and long-term contracts and operate or rent space in storage facilities that allow them to mitigate some of the fluctuations in the market price of natural gas.[16]

The price of the natural gas itself, however, reflects the operation of the open market. Therefore, the amount of money LDCs pay to purchase natural gas for their consumers is passed through to consumers directly through a purchased gas adjustment. LDCs report to the Public Utilities Commission on their gas purchases and on amounts charged to customers through the purchased gas adjustment, for review by the Department of Commerce and interested parties and approval by the Public Utilities Commission. This review is summarized in the Annual Review of Purchased Gas

[16] Most of the storage by Minnesota's natural gas utilities is in underground geologic formations in Michigan and the southern United States. In Minnesota, local storage of natural gas is found only in a salt dome near Watertown and a facility that liquefies and stores natural gas in a southern suburb of the Twin Cities.

Adjustments, where expenses of companies can be examined and disallowed if found to be inappropriate.

The provision of natural gas utility service was not always regulated in the same way that it is today. Prior to the 1970s, gas utilities were vertically integrated monopolies that owned production fields or rights, the interstate pipeline to transport the gas to market, and the local distribution facilities to provide the product to retail customers. The commodity price of natural gas was regulated by the federal government through price caps, instead of the market.

This system was in place until the early 1970s, when shortages of natural gas began in the United States. Price caps on natural gas resulted in suppliers harvesting only the natural gas fields that could produce a profit at the cap price. As a result, United States natural gas supplies decreased just when the demand for natural gas increased due to heavy industrial use, use for electric generation, and lack of conservation measures. The combination of these forces resulted in the United States being short on natural gas supplies, leading to curtailment of natural gas service to some customers and areas.

Congress passed the Natural Gas Policy Act of 1978 to address these problems. The law implemented measures to reduce use of natural gas by promoting conservation measures to restrict the use of natural gas in new construction, industrial processes and electric generation and ban it outright for applications like outdoor gas fueled ramps. At the same time, the law tried to increase the supply of available natural gas by removing the price caps that had discouraged exploration and production, thus deregulating production. This law began the drastic process of deregulating natural gas prices and breaking up vertical monopolies in order to open natural gas services more to market forces. A series of major orders by the Federal Energy Regulatory Commission, notably FERC Orders 436, 500 and 636, put into place this restructured gas market. As a result of these orders, the production of natural gas was completely deregulated as to price, the interstate pipelines were separated from LDCs and required to provide nondiscriminatory open access transportation service to LDC purchasers and large industrial users, and the LDCs continued to be regulate d on the state level but now purchased both natural gas supply and transportation services on an open market.

The results of the Natural Gas Policy Act were fairly dramatic. Initially, gas prices soared at the beginning of the 1980s, largely because gas production increased as fast as possible but the production increase required some lead time. The higher prices of natural gas and the possible shortages of natural gas spurred conservation efforts that caused demand to decrease steeply between 1973 and 1988. When new production efforts had been implemented, prices fell and then stabilized after 1983. The new production provoked by the move to an open market for natural gas created a surplus of available natural gas that has been referred to as the “gas bubble.”

Throughout the late 1980s and the 1990s, natural gas prices were low and predictable, with real 1998 prices close to 1970 prices. With natural gas prices lower in the summer due to less demand, natural gas utilities could purchase natural gas for storage at lower summer prices and then use that stored gas in the winter to protect against price fluctuations during the higher demand winter months. On the demand side, energy use grew but was moderated by conservation and energy efficiency measures. One of the true success stories in energy conservation is the steady decline in average gas usage by individual households over the past 30 years.

At the end of the 1990s, the low price of natural gas and the significantly lower air emissions caused by natural gas combustion facilities compared to coal plants, caused natural gas to become a preferred fuel for new electric generating plants. At the same time, the greater demand for use of natural gas to generate electricity in the summer caused summer prices not to decrease as much as they had in the past, therefore making storage of natural gas more expensive for LDCs. The “gas bubble” that had kept prices low was gradually dissipated by the end of the 1990s, but the long-term relatively low price of natural gas kept new production of natural gas low as well.

2000-2001 Heating Season

A combination of several factors led to the natural gas price spike that was experienced in the 2000-2001 heating season. In the months prior to the 2000-2001 season, the United States natural gas market began with higher than normal prices and a relatively low amount of natural gas in storage. This was due to several factors. First, a strong economy continued to push growth, and thus energy use. Second, hot summers in the southwestern United States in 2000 increased demand for air conditioning. Natural gas fired electric generators met the demand, which resulted in a huge increase in natural gas usage nationwide. This kept the price of natural gas high during the summer storage season, making the purchase of natural gas to be placed into storage very expensive. The diversion of gas to electric generation and higher prices resulted in a large storage deficit in the fall of 2000.

Going into the heating season, a “normal” weather season was predicted for the upcoming winter. What happened instead was that the United States and especially the northern tier states experienced the coldest November and December in more than a century. This very high demand, experienced early in the winter heating season, forced utilities to draw on already scant natural gas storage reserves sooner than normal. This left less stored gas available to counteract price volatility later in the heating season. For a sense of proportion, December 2000 storage withdrawals were the highest that had been experienced in the seven prior years. For the remainder of the winter, the price protection offered by the storage cushion was, for all practical purposes, lost.

The difficulty this situation posed for consumers of natural gas was that in January 2001 the price per Mcf of gas was over $10, compared with a price of $3.64 in January of 2000. This presented consumers with natural gas prices that had not been seen in more than 15 years. Unlike the 1970s, however, gas supply was tight but was not short, and gas service did not need to be curtailed. Curtailments were only applied to customers who chose to pay lower rates in exchange for the ability to have service interrupted in times of short gas supply. Gas prices began to stabilize near the end of winter at a range of $3.50 to $4.00 per Mcf.

The 2000-2001 heating season showed the sort of price volatility that can occur when there is a combination of increased demand, largely due to use of natural gas for electric generation in the previous summer, combined with low storage levels that decrease the ability of gas utilities to moderate commodity price swings, combined with increased usage caused by a significantly colder than normal winter. Figure 1-26 shows the commodity weighted average cost of natural gas paid by Minnesota's LDCs from July 1999 to July 2001, and illustrates the price fluctuations that were experienced as a result of these factors during last heating season.

The natural gas heating season of 2000-2001 ended with prices moderating substantially. Even with more than twice its funding as compared with recent years, however, energy assistance programs have unable to handle fully the energy needs of low-income consumers. Many customers with significant arrearages to their gas utility companies that needed to be paid back before the start of the 2001-2002 winter heating season. A combination of high arrearages from the past and the likelihood of more volatile prices over the next few years will place extreme stress on energy assistance programs, which have been underfunded for many years, and on the households they are intended to help. In January, the Department will publish the Energy Universal Service Report, required by the legislature, that will discuss options for coordinating the fragmented and inadequate pieces of energy affordability programs.

PETROLEUM

Minnesota has no native sources of petroleum products within the state borders. In the late 1990s, imports passed domestic supply as the major source of oil for the United States as a whole. The price of petroleum products is not regulated; it is determined by global market forces.

Most petroleum products enter and leave Minnesota by pipeline. Figure 1-27 is a map showing the approximate location of pipelines crossing Minnesota, as well as the location of petroleum refineries serving Minnesota. Some petroleum products are transported by barge, rail, ship or truck. All but a small portion of the United States' imported Canada crude oil and liquid petroleum gasses (LPG) pass through Minnesota on their way to other parts of the Midwest, eastern Canada, and New England.

The refined petroleum products used by Minnesotans are produced at two refineries located in the state, Koch Refining Company and Marathon Ashland Petroleum Company in the Twin Cities area, and the Murphy Oil Refinery located just across from Duluth in Superior, Wisconsin. Minnesota also obtains refined petroleum products from the BP-Amoco refinery in Mandan, North Dakota and the Tesaro refinery in Whiting, Indiana.

Use and Cost of Petroleum in Minnesota

Minnesotans consumed a total of 5127 million gallons of petroleum products in 1999. Petroleum products include coal, asphalt, and road oil, aviation gasoline, distillate fuel, jet fuel, kerosene, liquid petroleum gases, lubricants, motor gasoline, and residual fuel oil. Figure 1-28 shows total petroleum consumption in Minnesota for the various customer classes from 1970 to 1999. In 1999, Minnesotans used about 72 percent of all petroleum products for air, land and water transportation. This category includes use of fuels such as gasoline, diesel fuel and jet fuel. Most agricultural use of petroleum also falls under the transportation category.

In addition to transportation uses, approximately 21 percent of Minnesotans use either fuel oil or propane for their heating source. This use constituted about 6 percent of the total petroleum products used in 1999.

Figure 1-28 illustrates that petroleum product use has been relatively stable in many sectors, after declines in the late 1970s in response to two oil crises. The significant driver for the steady increase in the use of petroleum products between 1981 and 1999 has been the ever-increasing use of petroleum products for transportation purposes. Figure 1-29 illustrates that gasoline consumption trends are increasing at a greater percentage than the trend in increasing population in the state. This trend accelerated steadily during the 1990s.

In 1999, Minnesotans spent approximately $5 billion on petroleum products, as illustrated in Figure 1-30. Although Minnesota's expenditures on petroleum have not reached the high levels experienced in the late 1970s and early 1980s, a period of relative stability in petroleum prices appears to be ended. In the last couple of years, there have been more noticeable decreases and increases in the price of petroleum, based on factors that influence the supply and demand of the commodity and the operation of private markets.

Figure 1-31 shows the real prices in Minnesota for various categories of petroleum product since 1970. Price is largely influenced by the basic cost of crude oil and assessed taxes. World political and economic market forces primarily determine the cost of the crude oil. Federal and state governments assess the taxes on petroleum products.

Other factors that influence the price of finished petroleum products include supply shortages due to maintenance or damage on pipelines or at refineries. Since each petroleum product needs to be produced or "finished" and stored separately, some supply shortages also result from simple logistical problems associated with coordinating production and storage to meet current and future demand. Higher than expected demand for a particular petroleum product can also create temporary shortages that lead to higher prices. For example, a very cold winter increases the use of propane and fuel oil for home heating. Another factor that can influence the price of petroleum products is that most refiners have moved significantly toward just-in-time production, reducing storage costs at the facilities. Storage is now more in the control of independent terminal operators and pipeline operators. The trend to less storage and more just-in-time production lessens the ability of stored petroleum products to be used to moderate short-term price fluctuations in the market.

Environmental Impacts of the Use of Petroleum

Because the use of petroleum products is largely for transportation purposes in on- and off-road vehicles such as automobiles, trucks, tractors, motorcycles, four wheel drive vehicles, snowmobiles and motor boats, the environmental impact of petroleum products is directly related to the fuel efficiency and control technologies that might be in place on any of these vehicles, combined with their frequency of use. The major increasing use of petroleum products is in the transportation sector, illustrated by Figure 1-32, which shows the large increase in vehicle miles traveled in the state since 1970. The federal government regulates the required fuel efficiency and tailpipe emissions from vehicles. States have some authority in regulating fuel formulations to reduce emissions from vehicles.

Figure 1-33 displays the contribution of vehicles burning petroleum products to total statewide emissions for three key air pollutants: carbon monoxide, nitrogen oxides and volatile organic compounds. Ground-level ozone, commonly known as "smog," is formed when nitrogen oxides and volatile organic compounds combine in sunlight to form ozone. Emissions from vehicles fueled by petroleum products also account for the majority of emissions of several key toxic air pollutants.[17]

This report will not further discuss the issues surrounding the use, cost and environmental effects of petroleum products in the state of Minnesota, primarily because the petroleum industry is not regulated by the state, and the price of petroleum is not regulated. The state does monitor petroleum supplies and prices and does, through the Weights and Measures Division of the Department of Commerce, ensure that the contents of the products are what they purport to be and measuring devices are accurate.

Addressing the environmental issues surrounding vehicle emissions is outside the scope of this report.

[17] Minnesota Pollution Control Agency has found that vehicles contribute 58 percent of formaldehyde emissions, 67 percent of benzene emissions, 66 percent of 1, 3-Butadeine emissions, and 67 percent of POM emissions. MPCA Staff Paper on Air Toxics, November 1999 at 111, available on the MPCA website at www.pca.state.mn.us/air/airtoxics.html.

Figure 1.1: Energy End Use in Minnesota, 1999

Source: REIS and EIA

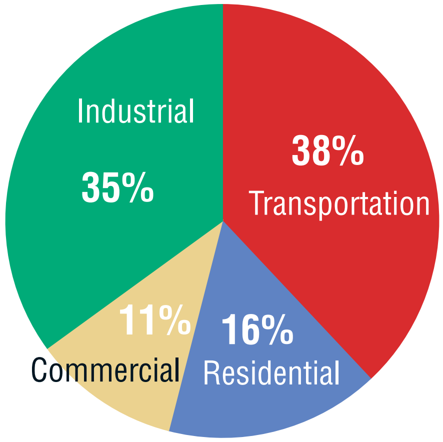
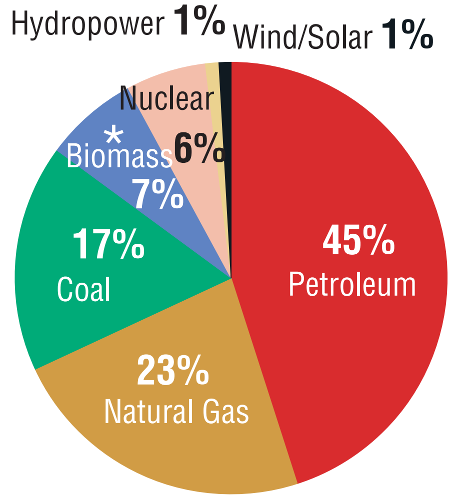


Figure 1.2: Inputs Used to Produce Energy Consumed in Minnesota, 1998

Sources: REIS and EIA



*includes wood and refuse-derived fuel generated by burning waste

Figure 1.3: Minnesota Electric Consumption, 2000

Source: REIS and EIA

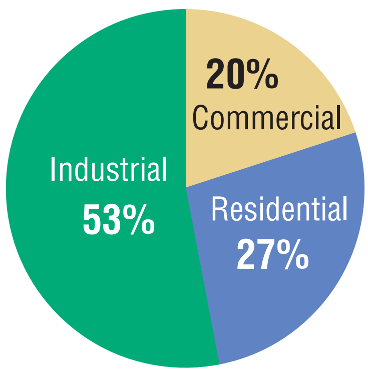
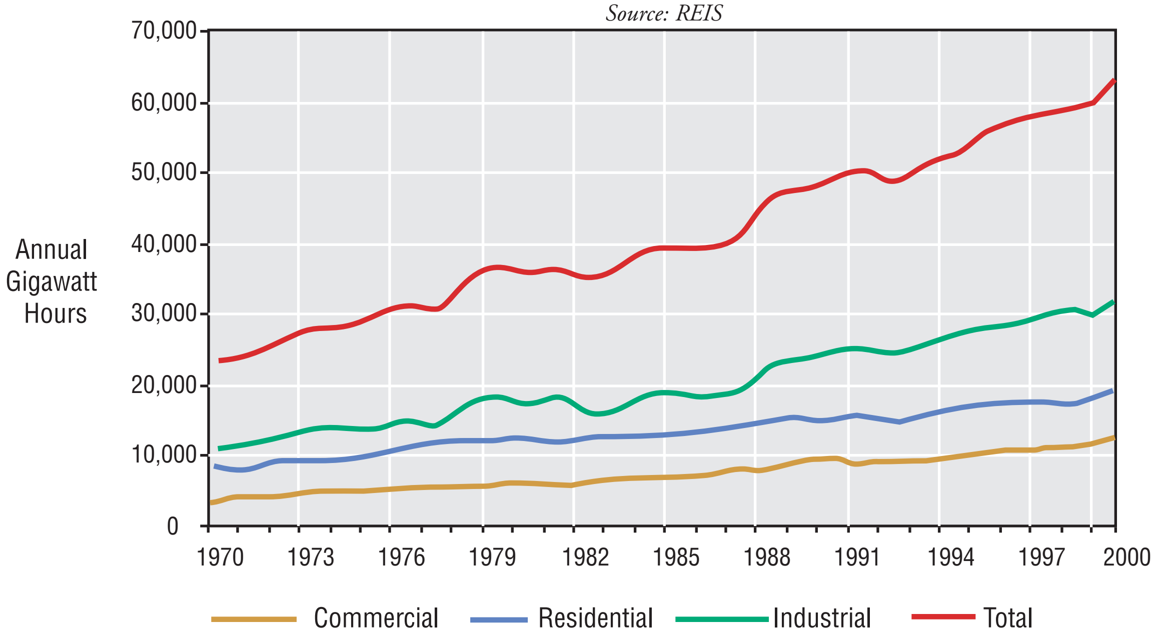


Figure 1.4: Minnesota Electric Consumption 1970-2000

Source: REIS



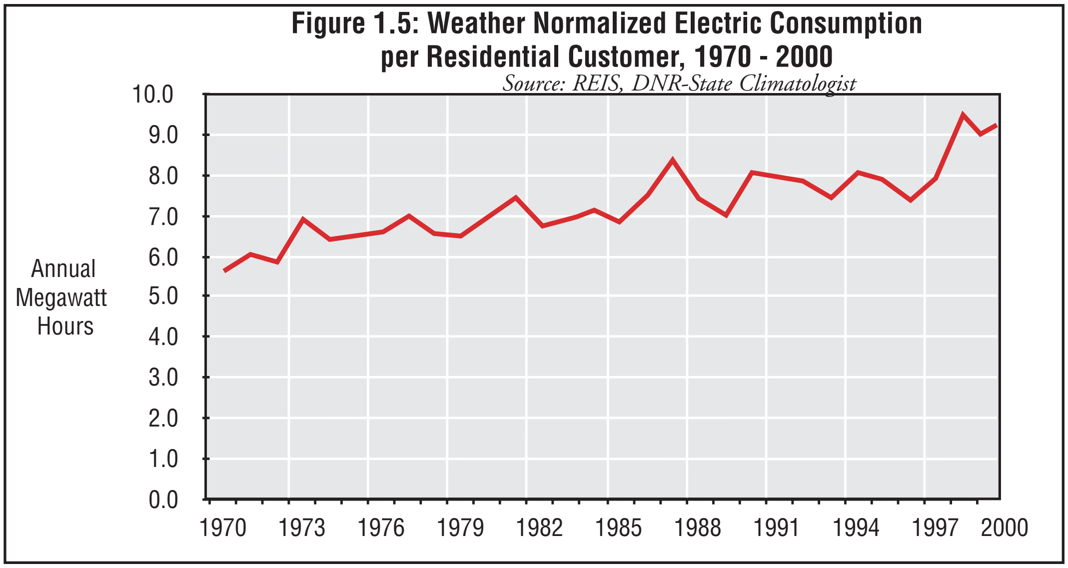


Figure 1.5: Weather Normalized Electric Consumption
per Residential Customer, 1970 - 2000
Source: REIS, DNR-State Climatologist
Annual
Megawatt
Hours
10.0
9.0
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000

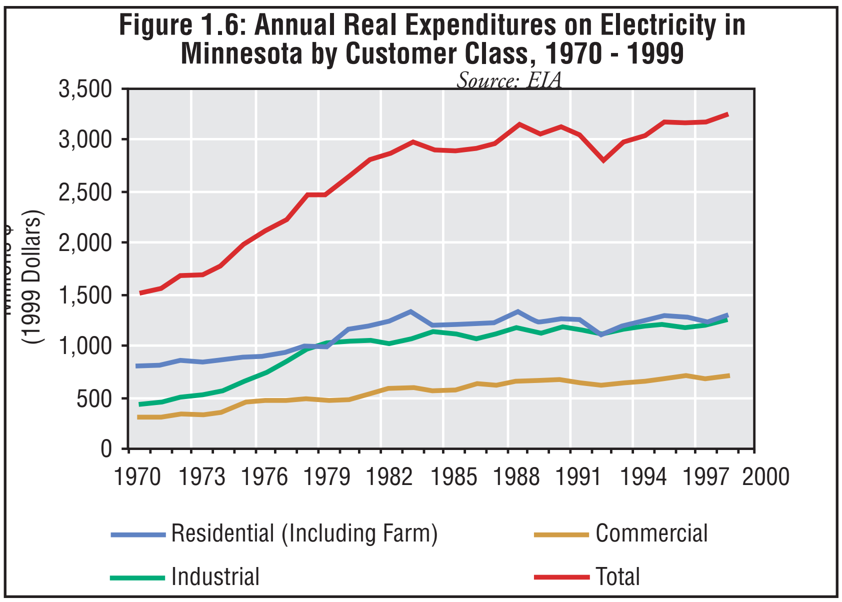


Figure 1.6: Annual Real Expenditures on Electricity in
Minnesota by Customer Class, 1970 - 1999
Source: EIA
(1999 Dollars)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
Residential (Including Farm)
Commercial
Industrial
Total

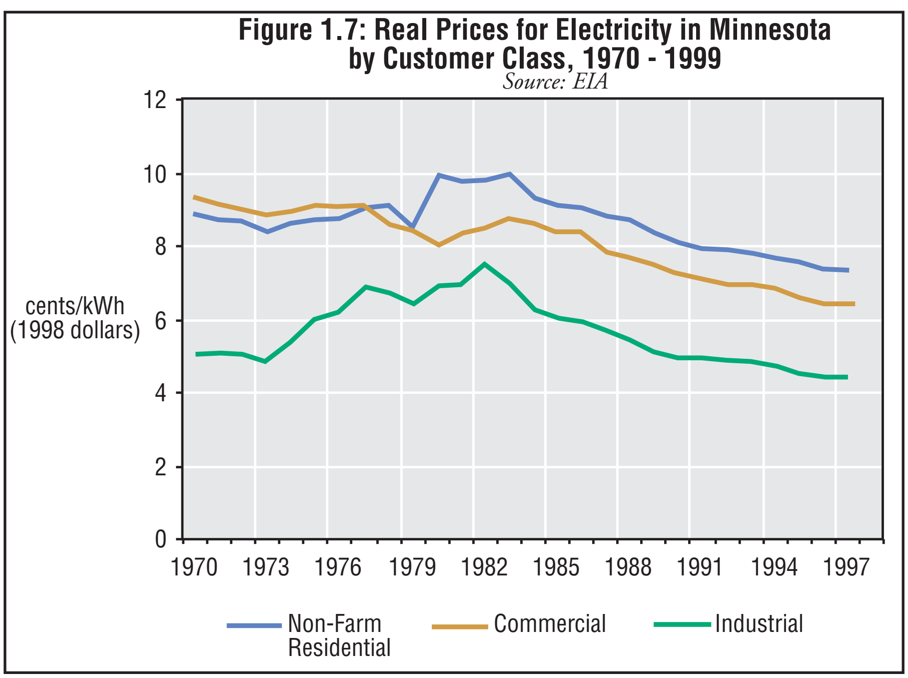


Figure 1.7: Real Prices for Electricity in Minnesota
by Customer Class, 1970 - 1999
Source: EIA
cents/kWh
(1998 dollars)
12
10
8
6
4
2
0
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
Non-Farm
Residential
Commercial
Industrial

Figure 1.8: Minnesota Electric Prices Relative to Prices in Other States, 1999 (¢/kWh)

	Residential Customers	Commercial Customers	Industrial Customers
Minnesota price	7.4¢	6.3¢	4.6¢
Minnesota rank	27	30	17
Average U.S. price	8.14¢	7.18¢	4.4¢
Highest price	14.1¢	12.7¢	9.6¢
Lowest Price	5.1¢	4.2¢	2.7¢

Source: EIA

Figure 1.9: Components of an Electric Power System

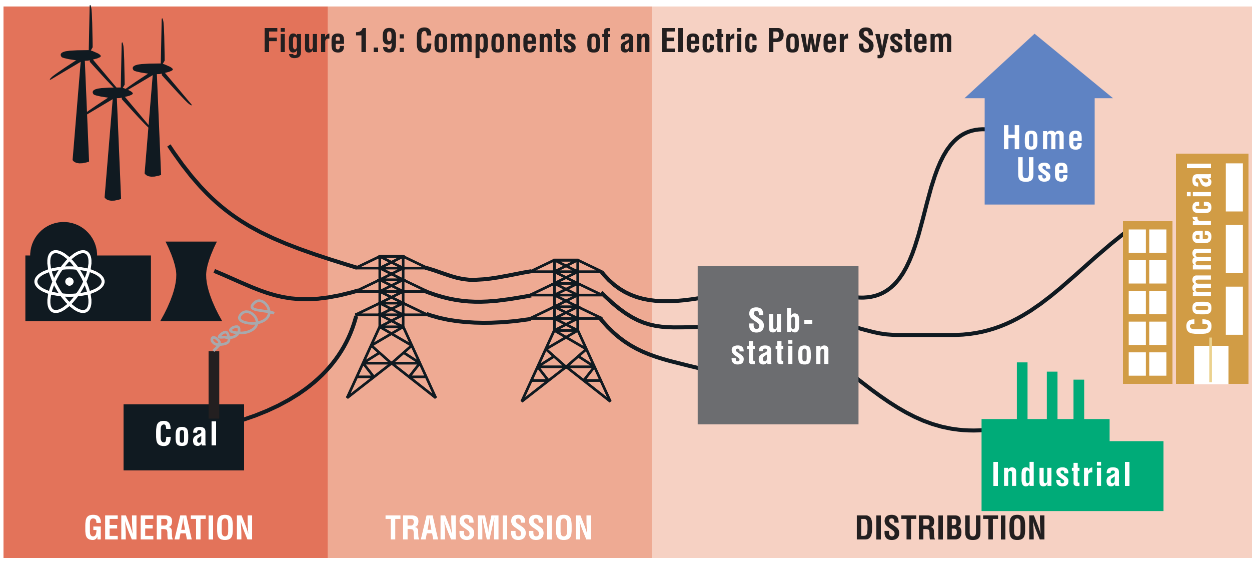


Figure 1.10: Daily and Monthly Load Curves for GRE and Xcel Energy, 1999

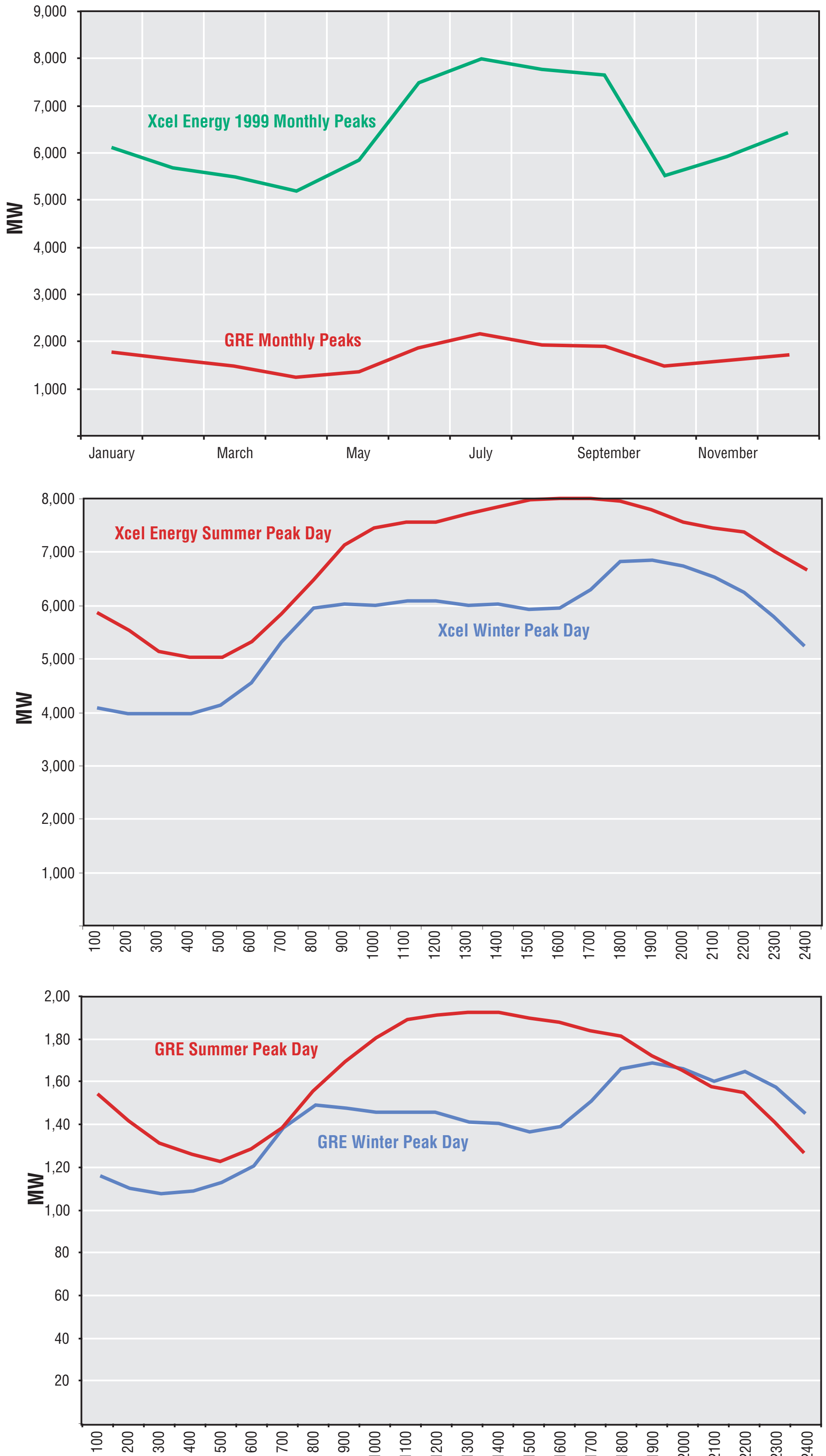


Figure 1.11: Electric Generating Plants with a Capacity over 100MW (1998)

Figure 1.12: Chronology of Construction of Minnesota Power Plants over 100MW (1950-2000)

Lakefield Junction (550MW)
Pleasant Valley (434MW)

2000

Lake Benton Power II (103MW)
Lake Benton Power I (107MW)

Cottage Grove Cogen (245MW)

1990

Sherburne County 3 (871MW)

Boswell 4 (565MW)

1980

Sherburne County 1/2 (1424MW)

Prairie Island 1/2 (1027MW)
Boswell 3 (372MW)
Inver Hills 1-6 (343MW)
Monticello (545MW)

1970

King (571MW)

Riverside 8 (222MW)
Hoot Lake (152MW)

Black Dog 4 (173MW)

1960

High Bridge 6 (170MW)

High Bridge 5 (97MW)
Black Dog 2/3 (214MW)
Laskin 1/2 (110MW)

Riverside 7 (150MW)

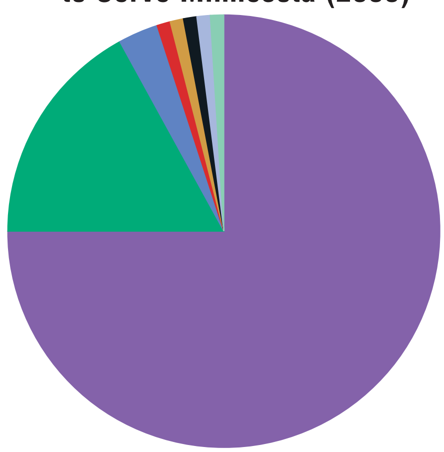
1950

Baseload Plant
Peaking Plant
Intermediate Plant

Figure 1.13: Power Plants Outside Minnesota that Serve Minnesota Customers in Part (1998) (over 100MW Capacity)

State	Plant	Utility	Capicity (MW)	Fuel	Operation
North Dakota	Coal Creek	GRE	1076	Coal	1979/80
	Coyote	OTP	149	Coal	1981
	Stanton	GRE	185	Coal	1966
	Young	MP/Minnkota	698	Coal	1970/77
South Dakota	Angus Anson	Xcel	232	Gas	1994
	Big Stone	OTP	444	Coal	1975
Iowa	Kapp	IPC	217	Coal	1967
	Lansing	IPC	260	Coal	1977
	Neal	IPC	134	Coal	1979
Wisconsin	Alma	DPC	189	Coal	1947/60
	French Island	Xcel	142	Oil	1974
	Genoa	DPC	320	Coal	1969
	Madgett	DPC	358	Coal	1979
	Wheaton	Xcel	342	Oil/Gas	1973
Wyoming	Laramie River	MoRiver	272	Coal	1980
Manitoba, CAN	Manitoba Hydro	Xcel	850	Hydro	1970s

Figure 1.14: Fuels Used to Generate Electricity to Serve Minnesota (2000)



Coal	75%	Nuclear	17%
Hydro	3%	RDF	1%
Natural Gas	1%	Wood	1%
Wind/Solar	1%	Cogeneration	1%

Source: REIS

Figure 1.15: Transmission Lines in Minnesota

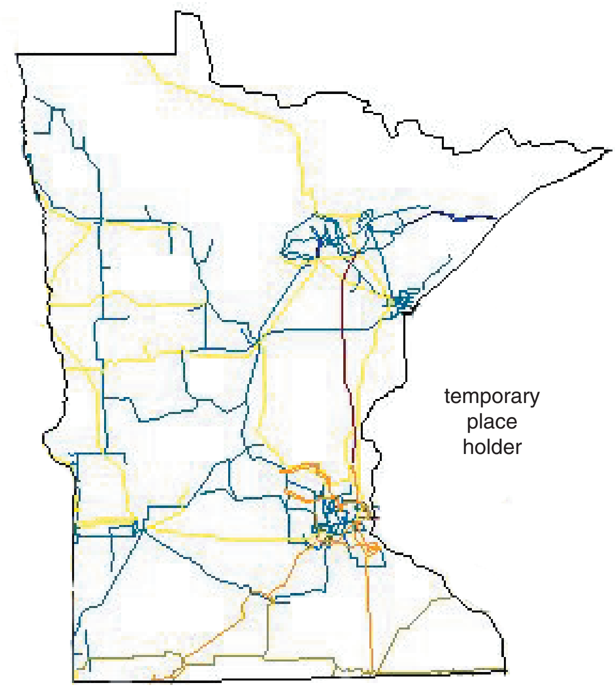


Figure 1.16: Percentage of Customers Served by Utility Type, 2000

Source: REIS

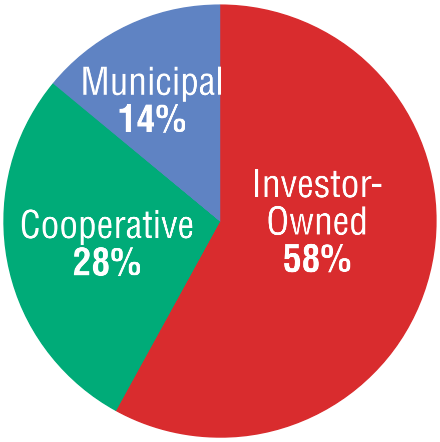


Figure 1.17: Electric Utility Service Area Map

Source: Provided by Great River Energy

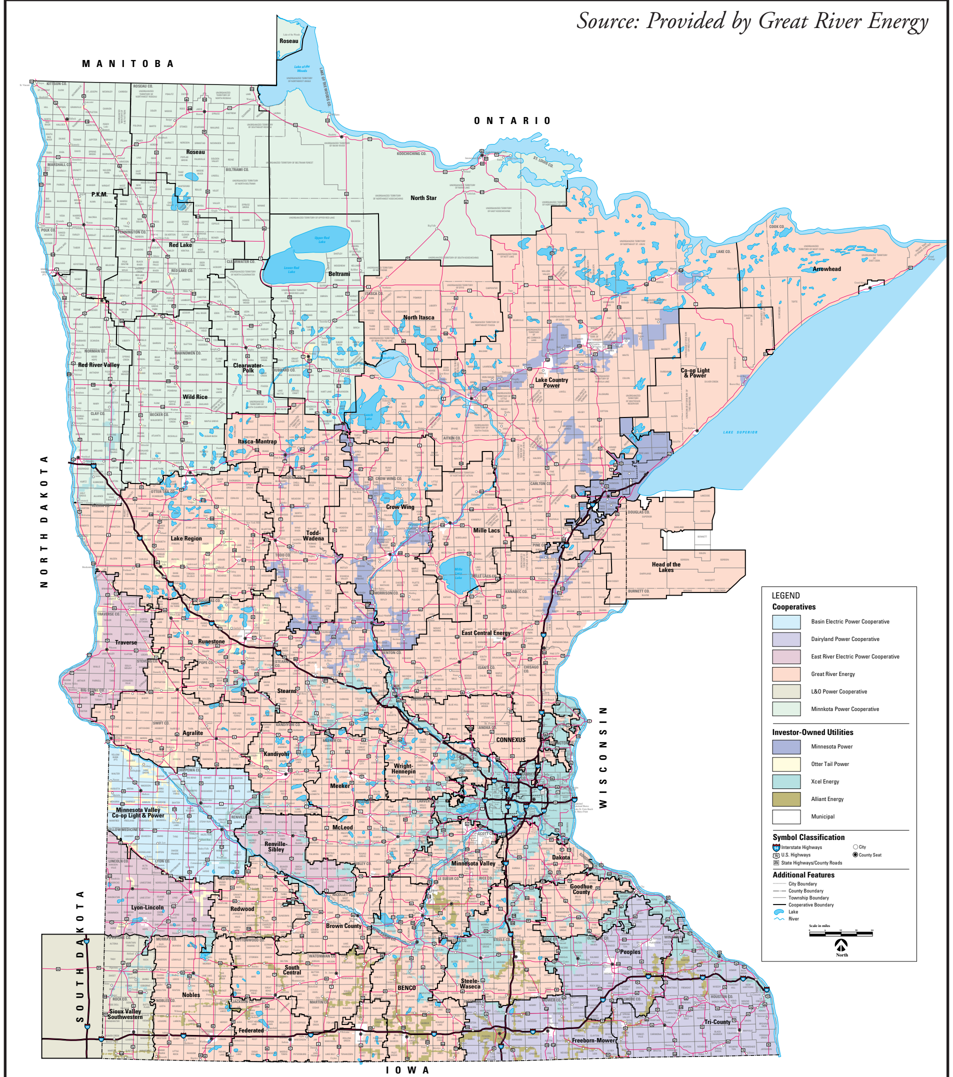


Figure 1.18: Natural Gas Pipelines in Minnesota

Figure 1.19: Natural Gas Utility System

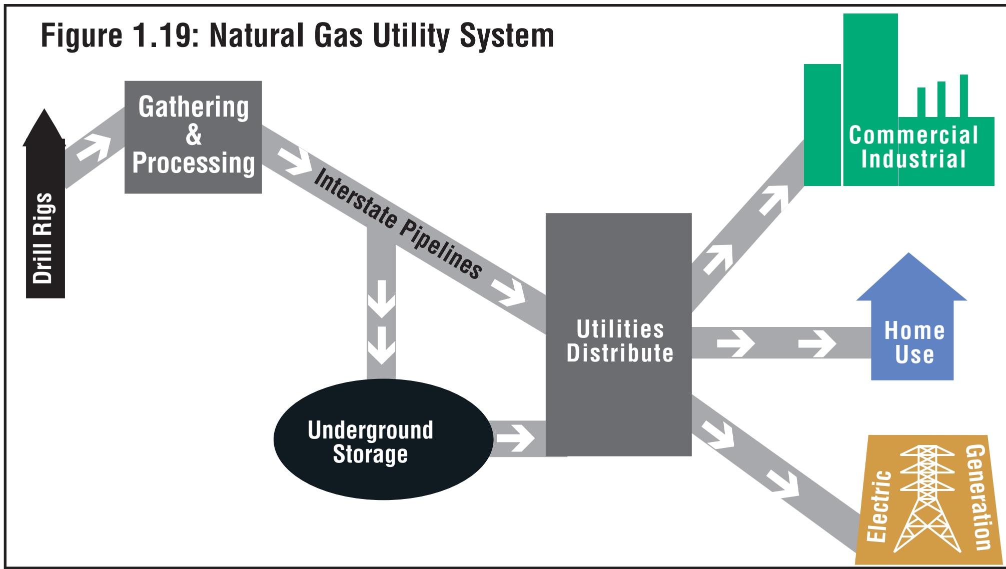


Figure 1.20: Natural Gas Consumption by Customer Class, 2000

Source: REIS

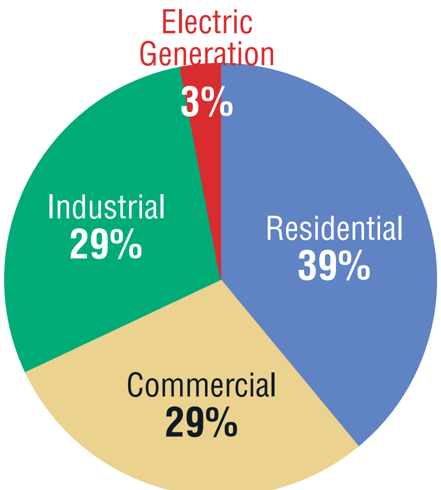
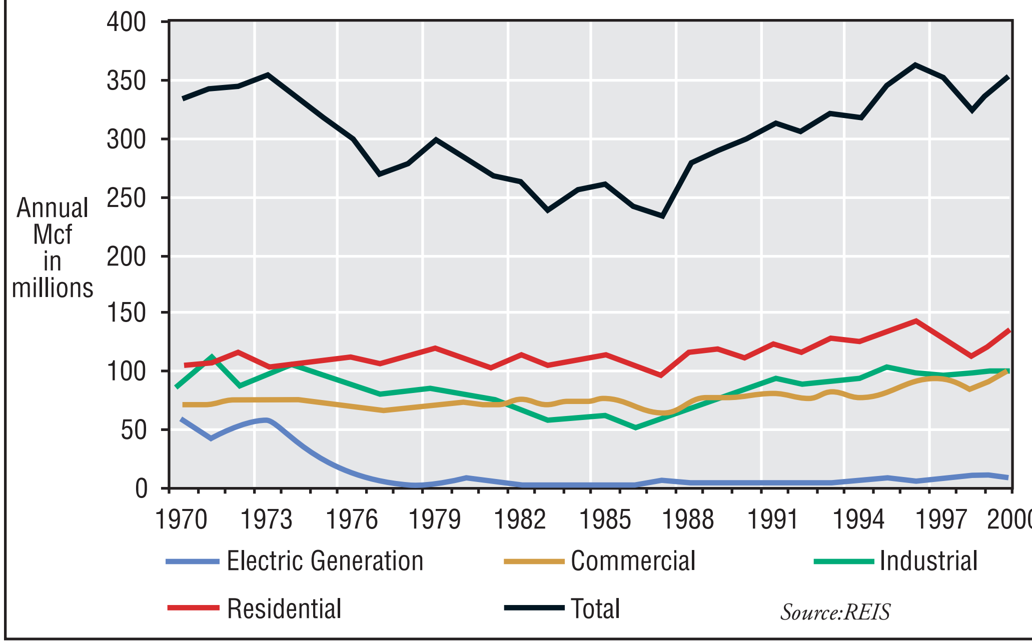


Figure 1.21: Natural Gas Consumption in Minnesota by Customer Class, 1970 - 2000



Source:REIS

Figure 1.22: Weather Normalized Natural Gas Consumption per Residential Customer, 1970 to 2000

Source:REIS, DNR-State Climatologist

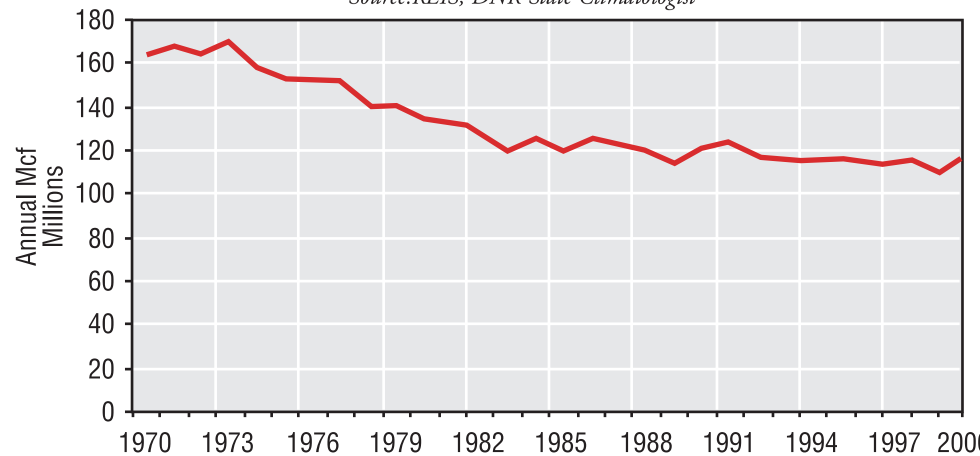


Figure 1.23: Annual Real Expenditures on Natural Gas in Minnesota by Customer Class, 1970 - 1999

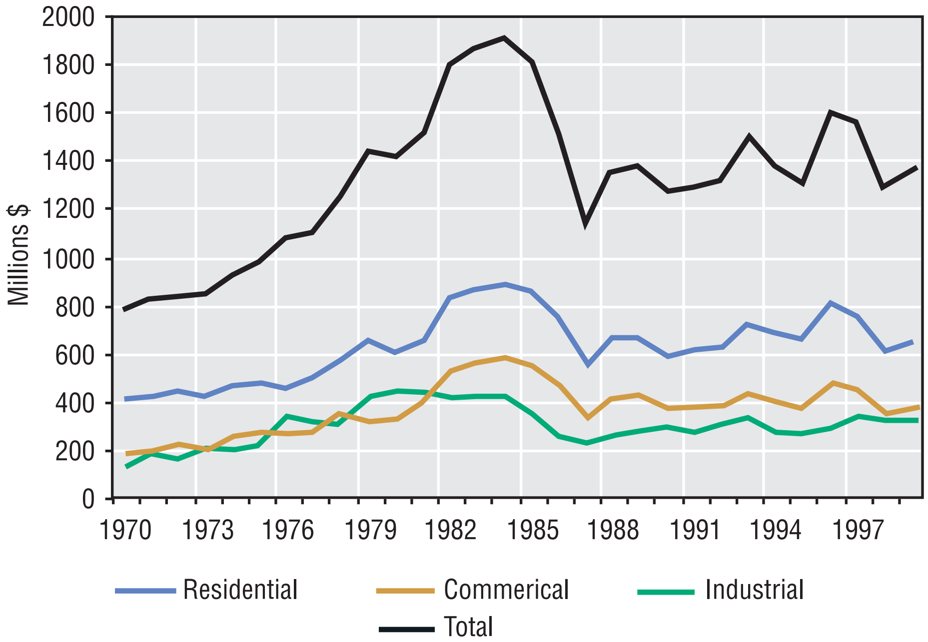


Figure 1.25: Minnesota Natural Gas Prices Relative to Prices in Other States, 1999 ($/ 1000 ft^3)

	Residential Customers	Commercial Customers	Industrial Customers
Minnesota price	$5.56	$4.44	$2.98
Minnesota rank	39	42	41
Average U.S. price	$6.69	$5.33	$3.10
Highest price	$18.97	$14.33	$8.21
Lowest Price	$3.64	$2.18	$1.25

Source: EIA

Figure 1.24: Real Prices for Natural Gas in Minnesota by Customer Class, 1970 - 1999

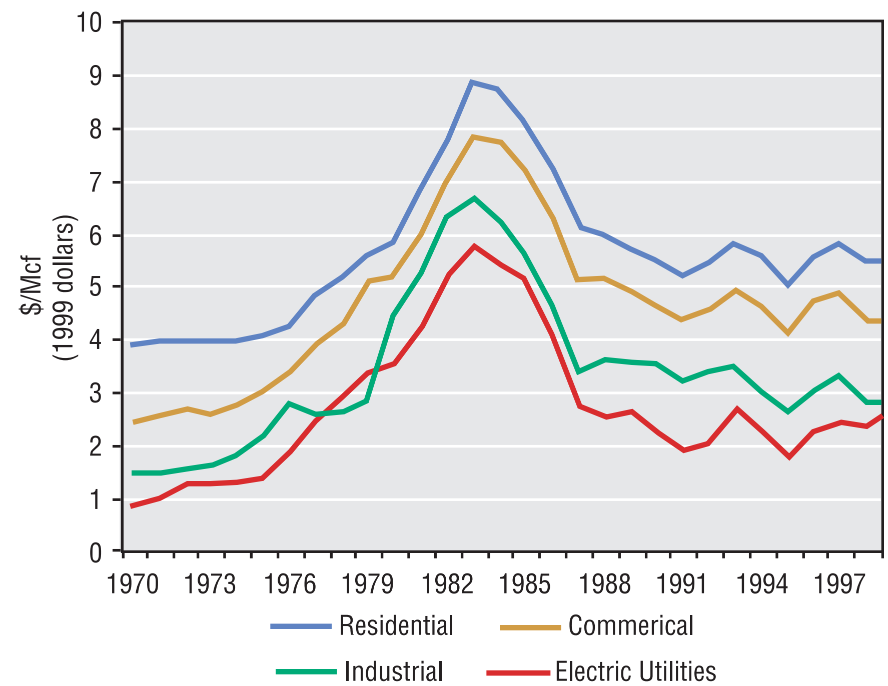
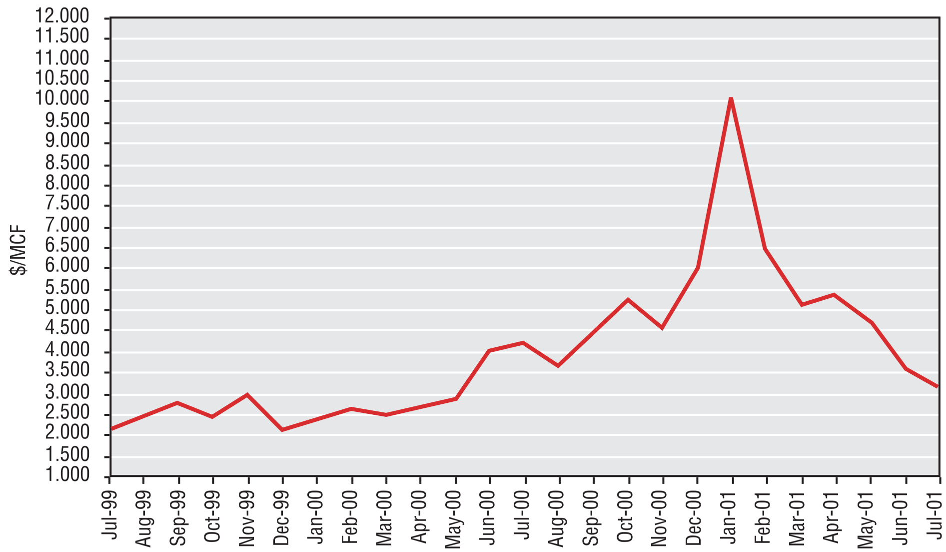


Figure 1.26: Commodity Weighted Average Cost of Gas for Minnesota Utilities, July 1999-July 2001



Source: Department of Commerce

Figure 1.27: Minnesota Petroleum Pipelines, Refineries and Product Terminals

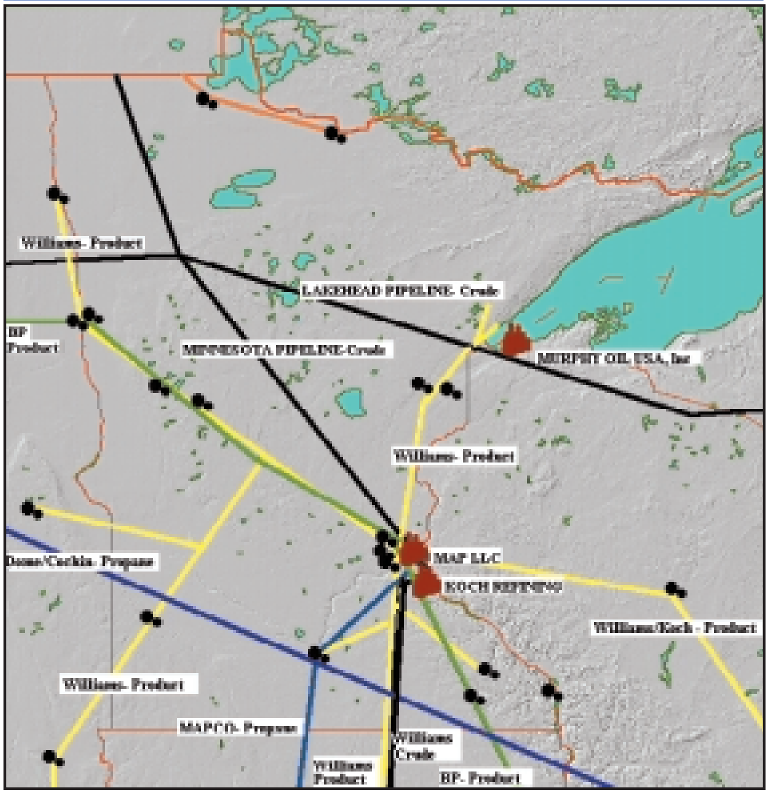


Figure 1-28: Petroleum Products Consumption in Minnesota by Customer Class, 1970 - 1999 (millions of gallons annually)

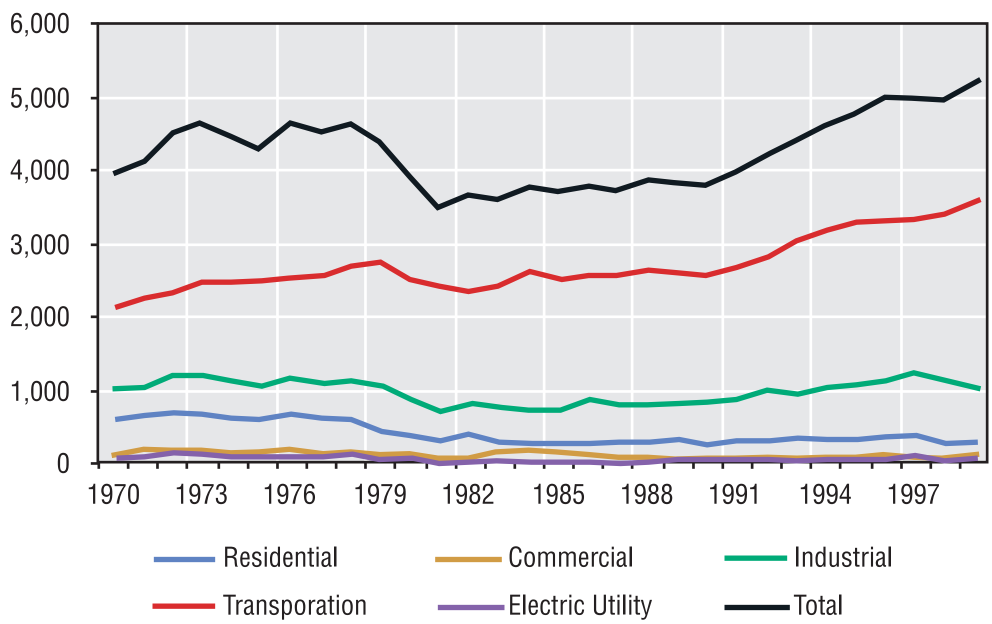


Figure 1.29: Minnesota Population and Gasoline Consumption Trends

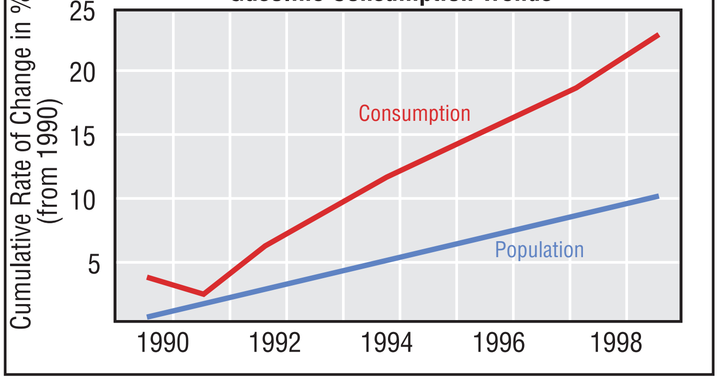
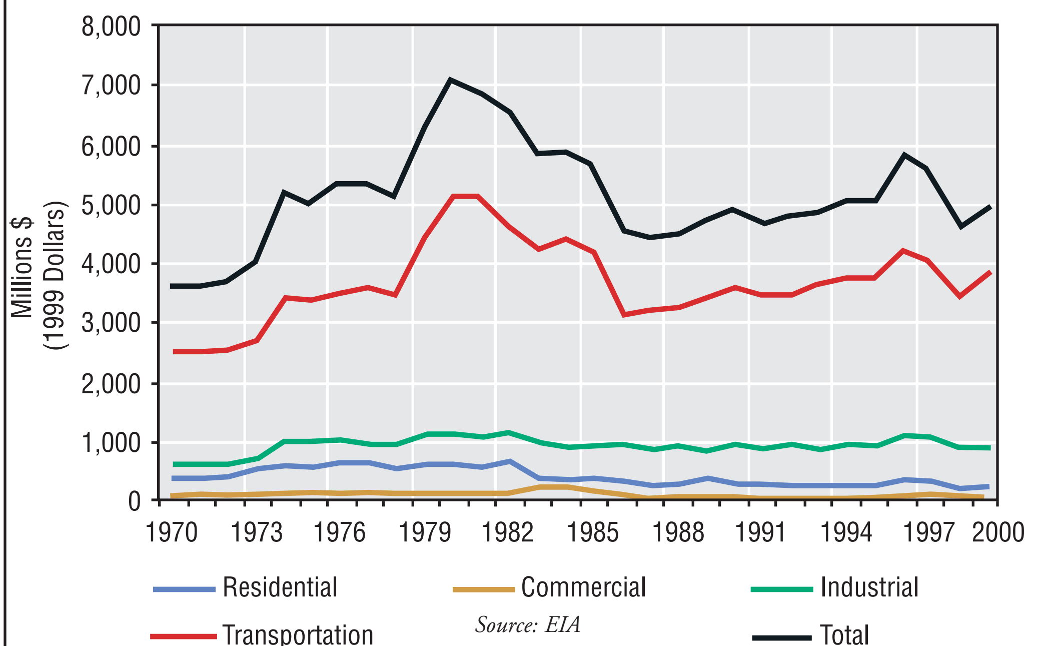


Figure 1.30: Annual Real Expenditures on Petroleum Products in Minnesota by Customer Class, 1970 - 1999



Source: EIA

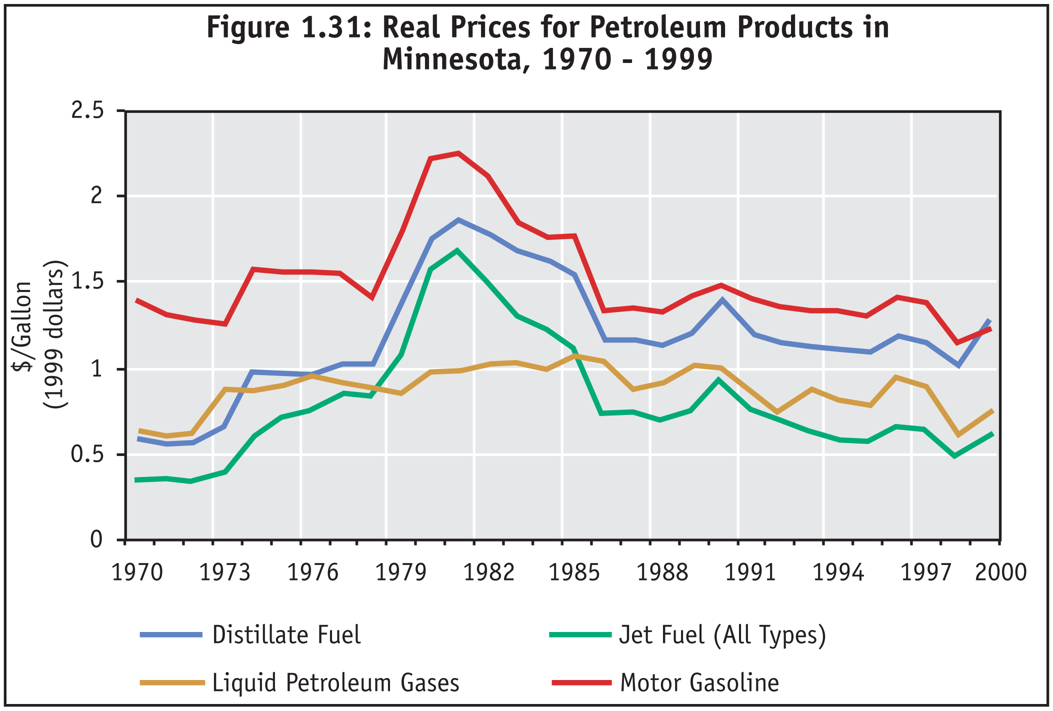


Figure 1.31: Real Prices for Petroleum Products in Minnesota, 1970 - 1999
$/Gallon
(1999 dollars)
2.5
2
1.5
1
0.5
0
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
Distillate Fuel
Jet Fuel (All Types)
Liquid Petroleum Gases
Motor Gasoline

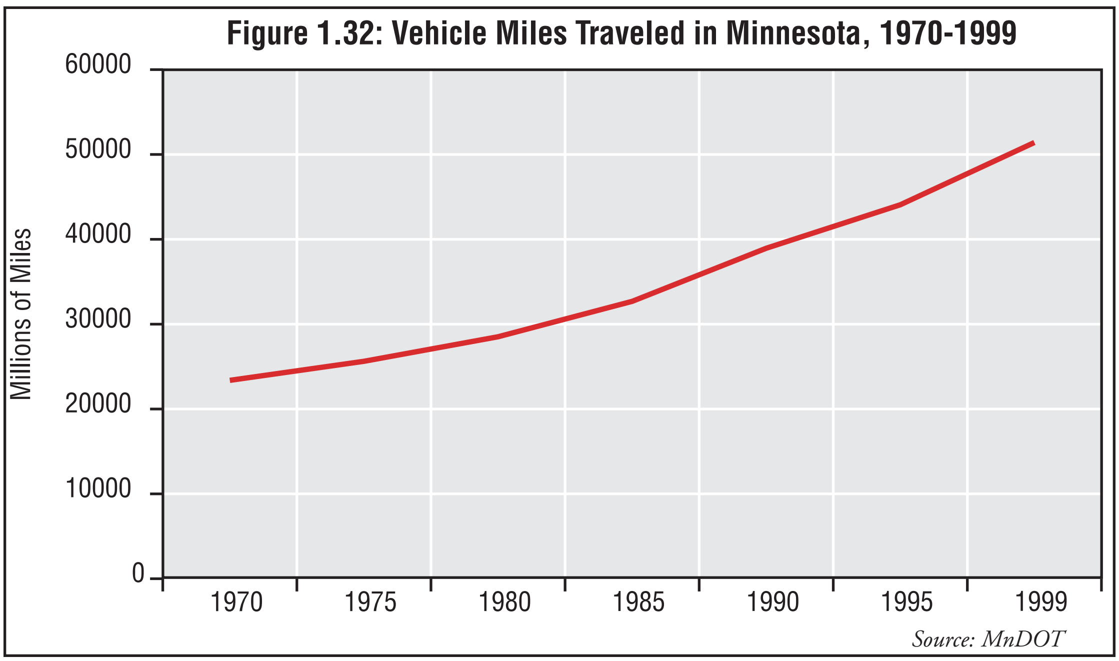
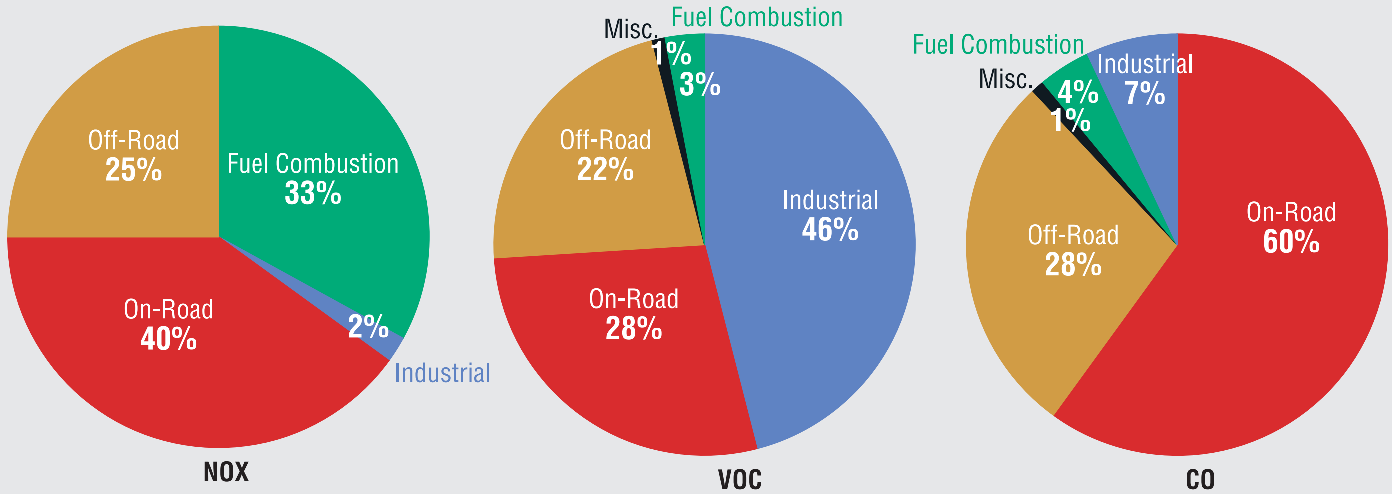


Figure 1.32: Vehicle Miles Traveled in Minnesota, 1970-1999
Millions of Miles
60000
50000
40000
30000
20000
10000
0
1970
1975
1980
1985
1990
1995
1999
Source: MnDOT

Figure 1.33: Sources of Nitrogen Oxides, Volatile Organic Compounds and Carbon Monoxide, 1999



CHAPTER TWO: THE EXPECTED FUTURE

Chapter 1 provided an overview of the history and trends in the use and cost of energy in the state and explained the current structure of each major energy industry. This chapter focuses on the expected future situation in two key areas: 1) forecasts of electric demand in the state until 2010 and the expected size of the generating capacity deficit, and 2) current forecasts of the price of natural gas, fuel oil and propane for the upcoming home heating season.

Forecasting is inherently subject to uncertainty because it tries to predict the future, and the future has a way of not working out exactly as predicted. Nevertheless, efforts to forecast future demand are critical to successful energy planning policymaking, because significant programs and infrastructure require years of lead time to be put into place to be ready to meet our energy needs.

FUTURE ELECTRIC GENERATING CAPACITY NEEDS

This section presents and discusses several perspectives on forecasts of our need for additional electric capacity by 2010. It presents forecasts done on a regional level by the Mid-Continent Area Power Pool (MAPP), statewide trend line analysis, and the individual system forecasts done by the various utilities as part of their integrated resource planning cycle.

Forecasting usage data from the past is an attempt to predict the future. The crudest type of forecast is a simple trend line. A trend line simply takes past energy usage and plots a line to fit the data. Figure 2-1 shows the application of a trend line for historic electric energy usage in Minnesota to predict future energy use. The trend line predicts that electric energy usage will increase by 1,267 GWh each year. Figure 2-1 extends the trend line 12 years into the future from the data for the period 1965-1998. By the end of the 10-year forecast in 2010, electric energy usage is predicted to grow to about 72,100 GWh annually. If electric energy usage occurred perfectly evenly throughout the year, a minimum of 145 MW of new capacity each year would be needed in Minnesota to supply the 1,267 GWh.[18] Because electric energy usage is not even through the year, more capacity than that would be needed to actually meet differing levels of growth in energy use.

A simple trend line is a poor forecasting tool because it does not allow the forecaster to identify the various factors that may influence energy usage and determine how they may influence future energy usage. Furthermore, it does not allow the forecaster to change those variables to produce a reliable forecast band. For example, the trend line may implicitly assume that the significant increases in labor force participation which occurred from the 1960s through the 1990s and are therefore part of the trend-line will continue even though such increases may not be possible in the future. A more complex forecast could analyze this and other questions. A trend line cannot explain what happened; it can only show on average what happened, and then assume that the exact same thing will continue to happen.

Typical variables that are used to produce more reliable forecasts include economic factors such as employment, investment, and output; weather factors such as heating degree days and cooling degree days; and other factors such as air conditioning saturation, number of customers, and population. Because different factors are more important in the short run and the long run, forecasters often use different equations for short-term and long-term forecasts and then blend the two together to create an overall forecast. For example, if a recession is imminent, a short-term forecast may focus on

[18] Electric energy refers to how much electricity is used during a given period of time, typically an hour, a month, or a year. Electric demand or electric capacity refers to how much electricity customers are pulling from the electric system in a given instant. These concepts are discussed in Chapter 1.

short-run economic variables while a long-term forecast may ignore a looming recession and focus on structural changes, both in the economy and in customer energy-usage patterns, that will have longer-term influence than a one or two year recessionary cycle.

Forecasting is most often performed on a utility system level. Each utility forecasts the demand in its service territory. Regional forecasts can be either done separately from the utility-specific forecasts or be based on accumulating the various utility-specific forecasts.

Electrically, the United States is divided into 10 different regions by the North American Electric Reliability Council (NERC). Each region is a voluntary association of electric utilities. Minnesota is placed in the Midcontinent Area Power Pool (MAPP) region. MAPP contains all or most of Saskatchewan, Manitoba, North Dakota, South Dakota, Nebraska and Minnesota. It also contains portions of Montana, Iowa and Wisconsin. MAPP was formed in the mid-1960s and presently performs three functions:

> it is a reliability council, responsible for the safety and reliability of the bulk electric system, under NERC;
>
> it is a regional transmission group, responsible for facilitating open access of the transmission system; and
>
> it is a power and energy market, where members and non-members may buy and sell electricity.

MAPP performs some utility planning to ensure the responsibility for safety and reliability of the bulk electric system. Each year, all utilities in the MAPP region file a *Load and Capability Report* with MAPP, which then assembles the various filings into a single document. MAPP's most recent *Load and Capability Report* was dated May 15, 2001.

To ensure a degree of commonality, we often use the MAPP *Load and Capability Report* to show the current forecast of use of electric energy and capacity in the region. The only major generation and transmission owning utility that serves Minnesota and is not in MAPP is Interstate Power Company d/b/a Alliant Energy which serves only a small number of customers in the state.

Regional Forecast

While there are several sources of forecasts for the region, we typically rely on forecasts from MAPP. One source of MAPP forecasts is the annual *Reliability Assessment* published by the NERC. The *Reliability Assessment 1999-2008* provides forecasts from each of the 10 NERC regions and an overall assessment. In the May 2000 *Reliability Assessment 1999-2008,* MAPP stated that "when load forecast uncertainty is taken into the account, the Region may be capacity deficit by summer 2000 and nearly 5,400 MW deficit by summer 2008." This 1999 forecast informed NERC of significant potential reliability concerns on the utility planning horizon in the MAPP region, and served to focus policymakers and utilities on the need to begin concerted efforts to assure that Minnesota's generation and transmission needs will be met in this decade.

The most recent MAPP forecast was issued in the spring of 2001.[19] MAPP's 2001 forecast shows electric generating capacity as being short 3,500 MW of meeting peak electric demand plus the 15 percent reliability reserve margin by 2010.[20] The lower figures reflect two new gas peaking plants that just came on line in 2001, plus other small generating unit additions. They do not reflect other proposed projects, some of which have been approved for construction.

Figure 2-2 illustrates MAPP's forecast of energy use from the *Load and Capability Report* data between 2001 and 2010. Figure 2-2 shows energy usage in the region rising from about 149,000 GWh in 2001 to 176,000 GWh in 2010.[21] This is equal to an annual growth rate of about 1.9 percent (or 3,019 GWh per year) for energy use in the MAPP region. The number of power plants that are needed to supply the energy is determined by an analysis of the capacity situation in the MAPP region.

Figure 2-3 provides the results of MAPP's analysis. Figure 2-3 shows that the MAPP region forecasts a net surplus of capacity through 2005. A small net capacity deficit is forecasted for 2006, with the net capacity deficit growing substantially to nearly 3,600 MW by 2010. This means that as a region, MAPP must either build new power plants, reduce electric demand growth[22] or find new imports from other regions by 2006. The alternative is to risk not having enough capacity to keep the system reliable and meet customers' energy needs.

Minnesota Forecast

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[19] MAPP issues forecasts for MAPP-USA and MAPP-Canada. This section presents the MAPP-USA forecast.

[20] The 15 percent reserve margin ensures that, even if a major power plant must be taken off the system during hours of peak usage, alternative power sources can be brought on line to keep the lights on.

[21] One GWh represents the amount of electricity 128 typical residential customers of Xcel Energy might use in a year.

[22] The forecasts include the reduction in demand that would have been achieved by the existing utility conservation programs. The forecasts do not include further reductions expected to be attained by implementing the 2001 legislative changes to the conservation programs. This is further discussed in Chapter 3.

This section attempts to provide insight into what Minnesota's statewide demand will be in 2010. This process must be treated as an approximation, for three reasons. First, statewide data are not available through the MAPP or utility forecasts. Second, the MAPP forecasts are based upon work done utility by utility and many utilities, such as Otter Tail Power Company and Xcel Energy, have operations in several states. Finally, to assure system backup and reliability, the electrical system was not designed so that a particular state could be easily isolated from other states. Therefore, we can produce only a crude forecast for energy use in Minnesota by fitting a simple trend line to data on statewide energy use that we gather.[23] The resulting trend line produces an estimate of about 60,719 GWh in 2001 and 72,122 GWh in 2010.[24] This equals an annual growth rate of about 1.9 percent per year for energy usage, the same growth rate MAPP assumed in its regional forecast. The trend line is illustrated in Figure 2-1.

In addition to the rough statewide forecast given above, the forecasts of the larger utilities doing business in Minnesota could be combined as well to try to get a picture of expected statewide demand growth.[25] Figure 2-4 shows the results of doing this from MAPP data. Figure 2-5 shows the larger utilities forecasting energy use of 86,607 GWh in 2001, growing to 102,533 GWh in 2010. These numbers are larger than the statewide numbers quoted above. This fact indicates that the large utilities have significantly more energy use outside of Minnesota than is used by the smaller Minnesota utilities excluded from the data. The large utility[26] energy forecast results in an annual growth rate of about 1.9 percent per year, roughly confirming the 1.9 percent growth rate forecasted by the trend line discussed above and the MAPP regional forecast.

The purpose of combining the large Minnesota utilities energy forecasts is that they create an estimate of the capacity surplus or deficit faced by the utilities serving the State. This is done in Figure 2-5 below. Figure 2-5 shows that the large utilities have a capacity surplus in 2001 (1,041 MW). That surplus first becomes a deficit in 2006 (653 MW). The deficit grows for the rest of the period, reaching 2,050 MW in 2010.

Utility Specific Forecasts

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[23] See the Department's *1998 Minnesota Utility Data Book*, which contains data for 1965 to 1998.
[24] In 2000, Minnesotans consumed 62,532 GWh of electricity, higher than the trend line prediction for 2001. See Figure 1-3.
[25] Here "large" is defined as being utilities that file data separately with MAPP and either file an integrated resource plan with the Public Utilities Commission or have a capacity surplus or deficit of at least 100 MW in one year.
[26] The organizations are Xcel Energy, Otter Tail Power Company, Minnesota Power Company, Great River Energy, Gen~Sys Energy (Dairyland Power Cooperative), Basin Electric Power Cooperative (representing East River Electric and L&O), Minnkota Power Cooperative, Southern Minnesota Municipal Power Agency, Missouri River Energy Services, Rochester Public Utilities, and Minnesota Municipal Power Agency.

There are eleven different utilities or organizations filing data with MAPP that meet the definition of 'large' as discussed above. The forecasted annual growth rate in energy use for each is provided in Figure 2-6 below. Figure 2-6 shows that annual growth rates vary from 4.0 percent per year for Missouri River to 0.8 percent per year for Minnesota Power.

The number of power plants required to produce the energy needs discussed above can be determined by a utility-by-utility capacity analysis. Of the 11 utilities, five show significant deficits (over 100 MW) and the other 6 have either small deficits or surplus throughout the planning period. By far the largest utility doing business in Minnesota, and the utility with the most significant capacity deficits, is Xcel Energy. In order to produce figures of readable scale, the capacity situation of Xcel is provided in Figure 2-7 and the capacity situations of the other four utilities with significant deficits are provided in Figure 2-8.

The capacity situations of the six utilities not forecasting significant deficits is provided in Figure 2-9. Of the six utilities falling into this category, four show surpluses (three of 50 MW or less), and only Otter Tail Power and Missouri River show small deficits (50 MW or less).

In addition to data provided to MAPP each April 1, certain utilities file Integrated Resource Plans (IRP) with the Public Utilities Commission (PUC). An IRP provides a comprehensive overview of a particular utility's forecasts, existing supply-side resources, existing demand-side resources, and action plans to meet potential deficits for a 15-year period.

Currently nine utilities file IRPs with the Commission.[27] The PUC's Order is binding with respect to rate-regulated investor-owned utilities and advisory for cooperative and municipal generation and transmission utilities. The utilities file their IRPs at various times, typically on an every other year basis. However, some of the cooperative and municipal utilities may have several years between IRP filings. Figure 2-10 shows the estimated surplus or deficit for each of the utilities filing an IRP in the short run (2001 through 2006).[28]

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[27] The 9 utilities are: Alliant Energy Corporation, Minnesota Power Company, Otter Tail Power Company, Xcel Energy Inc., Dairyland Power Cooperative, Great River Energy, Minnkota Power Cooperative, Inc., Missouri River Energy Services, and Southern Minnesota Municipal Power Agency.

[28] The numbers presented for Minnesota Power are the Company's figures. The Department of Commerce disagrees with those figures and believes the surplus is substantially larger, because Minnesota Power did not factor into its forecast certain peak management opportunities available to it. The exact size of this is known to the Department, but is claimed a trade secret by Minnesota Power and is thus not included in this report. The numbers presented for Great River Energy (GRE) are GRE's figures. The Department has questioned the accuracy of GRE's filing, and expressed concern over how load-building activities have played a role in GRE's capacity situation. Since IRPs are only advisory for

Figure 2-11 shows the estimated surplus or deficit, before implementation of any identified action plan, for each of the utilities filing an IRP in the long run (2007 through 2015). Since the filings are made at different times and in different manners, not all of the utilities report a surplus or deficit number through 2014.

Figures 2-10 and 2-11 show that virtually all of the utilities have a deficit at some point during the next 15 years. Therefore, all of the utilities have action plans which involve acquiring more resources. These plans may include more demand-side management conservation, more construction of power plants, short-term purchases from the market, long-term purchases from the market, and combinations of the above. Figure 2-12 below summarizes the IRP capacity additions planned by the utilities, by year and size, for new power plant construction and signing long-term power purchase agreements with other power generators (also known as PPAs).[29] In most cases, it is not clear what type of generation technology will be proposed or built.

This in-depth forecasting analysis shows the importance and the appropriateness of continuing with an IRP or similar process to evaluate future resource needs of each utility system. The different utility systems are experiencing very different growth rates, 0.8 percent to 4.0 percent per year, for different reasons. Similarly, five of the 11 large utility systems have major capacity deficits forecast for 2010, two have small deficits, three have small surpluses, and one has a large surplus. It is the specific situation of each utility system that must be monitored, and any response to the statewide capacity deficit must consider the different circumstances of individual utility systems.

In the process of creating this report, we have been able, for the first time, to analyze individual utility IRPs in relation to each other. It is clear that IRP is very important as a collection of forecasts and action plans than as isolated documents in attempting to gain an overall view of future electricity needs in the state.

The regional, statewide and utility-specific forecast perspectives presented in this section show an estimated Minnesota capacity shortage of at least 2,000 MW by 2010. The next chapter will discuss the available strategies for meeting this electric demand. The rest of this chapter will continue to address the theme of the expected future by providing current forecasts for the prices of home heating fuels next winter.

GRE, the Department's comments are simply a matter of public record. No binding PUC Order is pending, but PUC will issue an advisory Order.

[29] Xcel Energy uses a bidding process to choose generation capacity from either independent power producers, other utilities, Xcel or Xcel's subsidiaries. Xcel has bid in this process, but has not won a bid.

NATURAL GAS, FUEL OIL AND PROPANE PRICE EXPECTATIONS, 2001-2002 WINTER HEATING SEASON

While 63 percent of Minnesotans heat their homes with natural gas, 11 percent heat their homes with propane and 10 percent with fuel oil.[30] This section will discuss current predictions for the prices of each of these heating fuels in the 2001-2002 winter season.

Natural Gas

Current indications are that consumers in the 2001 to 2002 winter heating season will experience significantly lower and more stable prices than occurred in the last heating season. The price of natural gas has fallen over the last six months from a high of $9.98 per Mcf in January 2001 to an October 2001 price of $1.83 per Mcf.

The run-up in natural gas commodity prices that was experienced last winter and discussed in Chapter One has caused drilling for natural gas to increase dramatically. Figure 2-13 shows the increase in natural gas drilling rig count between April of 1999 and July of 2001. The number of rigs out drilling for and producing natural gas has almost tripled in this two-year period. Although there is a time lag in supply increases from onset of drilling to delivery of marketable natural gas, the rig count is a favorable indicator of increased supply.

Several other general factors that influence supply and demand of natural gas have so far been favorable for lowering its price. California and Texas in 2001, unlike in 2000, did not experience warmer than normal weather in the summer of 2001. This reduced their need for electric generation for air conditioning, and, since these states both rely on natural gas electric generation more than any others, reduced the summer peak use of natural gas this year. In addition, the effect of electric conservation on electric demand in California has similarly reduced the demand for natural gas to generate electricity this summer. In 2001, less gas-fired electrical capacity has been added than was added in 2000. Finally, the United States' economic downturn is lessening the industrial demand for natural gas.

The lower prices have resulted in gas utilities sending natural gas to storage facilities at a rate well above average. At present, 2.22 billion cubic feet of natural gas is being stored in the lower 48 states, a figure 7½ percent higher than the average storage level in the years 1995 to 2000 (2.067 billion cubic feet). With the commodity price for natural gas lower this summer than last summer, storage has proceeded at high levels

[30] The remaining homes heat with electricity (11 percent) and wood (5 percent).

Figure 2-14 illustrates the variations in natural gas prices throughout the months of the year for each of the last five years, starting in 1997. The graph demonstrates that, while natural gas prices have been lower in the summer of 2001 than in the year 2000, they have stabilized at prices higher than the summer prices in the years 1999 to 1997. This is due to the fact that natural gas supply and demand are more in balance than they have been in 15 to 20 years.

The stabilization of price at higher levels also illustrates the effect of now having both a high winter peak demand, and a smaller but higher than historic summer peak due to the use of natural gas to generate electricity. This fall's reduction in the price of natural gas to levels comparable to the years 1997 to 1999, between $2.00 and $2.50 per Mcf, illustrate the continuing effect of the economic downturn on industrial demand.

Figure 2-15 shows the prices for natural gas futures between September of 2001 and March of 2004. This shows that prices have appeared to stabilize at a rate of between $2 and $3 per Mcf, significantly lower than the peak prices of last January. This figure also indicates that prices will stabilize in the near future at a higher level than consumers became used to in recent years, with natural gas prices being generally between $2 and $4 per Mcf.

There is a time lag before it will become evident whether the increase in drilling will produce significant new supply, and whether consumers' reaction to higher, more volatile prices of natural gas will provoke more efficiency and conservation measures. Either of these trends could favorably impact the price of natural gas and make it lower than the current levels. On the other hand, the same factors that heavily influenced the increase in natural gas prices in the year 2000 could re-emerge and increase natural gas prices as well.

Figure 2-16 shows a current projection of natural gas demand in the lower 48 United States through 2010. As can be seen from the figure, most sectors are predicted to continue their steady, historic growth rates in the consumption of natural gas. The significant difference is that in the next ten years, the use of natural gas to generate electricity is expected to increase substantially, nearly doubling by the end of the decade.

The increase in prices is expected to boost production of natural gas, as it did in the 1970s and early 1980s. Natural gas storage will remain important, but storage decisions are impacted by the fact that there is now a summer peak demand for natural gas, which is likely to result in higher than historical summer prices. This increased use of natural gas overall also creates a transportation issue. It could very well require significant new capital investment in natural gas pipeline capability, as older pipelines that were largely built 40 to 50 years ago start to reach overall capacity. For the first time in almost 20 years, natural gas supply and demand is in closer equilibrium, which means that there will be more frequent swings in the price of natural gas based on supply-demand balance at any point in time.

Fuel Oil and Propane

This section presents the most recent forecast done by the U.S. Department of Energy's Energy Information Administration.[31] Fuel oil is produced by refineries from crude oil, and propane is produced both by the processing of natural gas and by the refining of crude oil. Therefore, the prices of both fuel oil and propane correlate very closely with the price of crude oil. Figure 2-17 illustrates this relationship for both fuels.

In the winter of 2000 to 2001, storage entered the winter at below normal levels due to the increased price of crude oil. With high demand caused by extremely cold November and December months, inventories were drawn down, and the ability of storage to moderate price volatility was decreased. As a result, prices for both of these fuels increased for consumers during the last heating season.

The current forecast is that crude oil is expected to stay at a price range between $20 to $30 a barrel through early 2002. This price average, however, even if it holds up, does not prevent short-term swings in the price of this commodity. Global inventories of crude oil are lower than normal, and thus will serve less to moderate any price volatility that appears. OPEC has reduced production by 3.5 million barrels per day so far this year. This is predicted to leave crude oil inventories at the low end of the normal range, potentially creating a tight crude oil market this winter.

Due to heavy demand for heating oils in the early part of last winter, with a bitterly cold November and December, demand for fuel oil rose sharply in November and December and reached highs well above any highs that had occurred since 1995. The result of this strong price increase was increased production of fuel oils in January, largely due to a dramatic increase in imports after the November/December price spike. These imports were available to the United States because Europe had a warmer than normal winter. Russia especially was able to provide massive imports that helped the United States get through the winter heating season on better footing. Figure 2-18 illustrates the difference in demand between the average of the years 1995 to 1999, and the fuel oil demand levels of last two winters.

As we head into the 2001-2002 heating season, storage levels for fuel oil are slightly over average at 11 million barrels. The five year average has been 10 million barrels, which is lower than the average of the last 10 years (15.5 million barrels). As a result, the current EIA prediction is that prices will be a little lower than the prices for fuel oil were last winter.

[31] The full forecast can be viewed at www.eia.doe.gov/neic/speeches/main.html#Aug2001.

U.S. propane production fell sharply in the winter of 2001 because when natural gas prices were very high at the end of 2000, the incentive was to not strip the propane out of the natural gas stream, instead keeping these Btus of energy in the natural gas. As a result, propane production from gas plants fell sharply during the winter heating season. As Figure 2-19 shows, U.S. propane production rebounded quickly in the early months of 2001 and, while below 2000 levels, exceeds production levels at similar times of the year in 1999 and exceeds the average of the years 1996 to 2000.

Propane demand is highly seasonal, with a winter peak 50 percent higher than summer peak use, but production of propane and imports of propane do not vary much throughout the year. As a result, inventories that are built up in advance of the high season of demand in the winter balance the market price of propane. Nationally, inventories of propane are in the average range, but are 41 percent higher than last year.

In the Midwest, however, current inventories are lower than average, as illustrated by Figure 2-20. This could cause some concern, because the Midwest is one of the highest consuming regions for propane in the country. In the gulf coast region, however, storage is 33½ million barrels above normal, and, barring a pipeline problem, there is time to get these propane stocks to the Midwest before the winter heating season.

The current EIA forecast is that residential propane prices will be lower than those last winter, although any unforeseen changes in the price of crude oil and natural gas would affect propane, as well as any problems that emerge with bottlenecks in a pipeline system that is operating near capacity.

Figure 2.1: Minnesota Electric Energy Useage Trend Line, 1965-2009

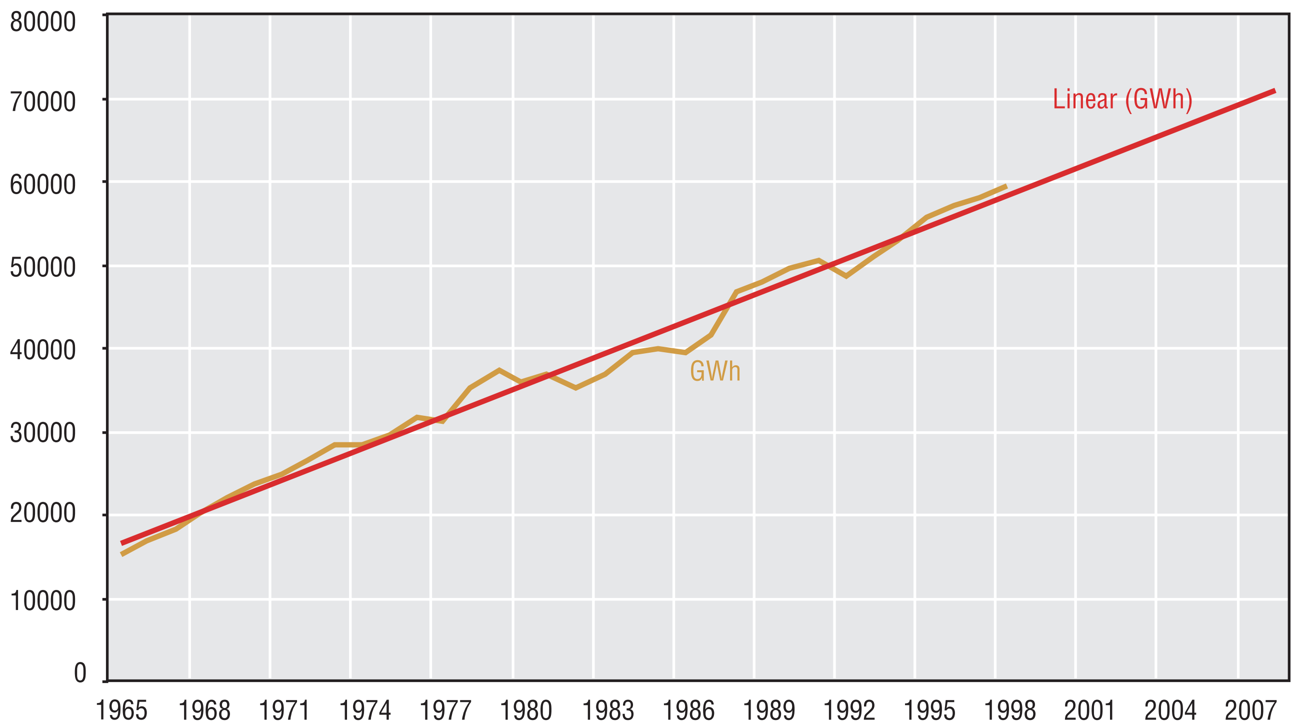


Figure 2.2: MAPP U.S. Region Energy Forecast, 2001-2010

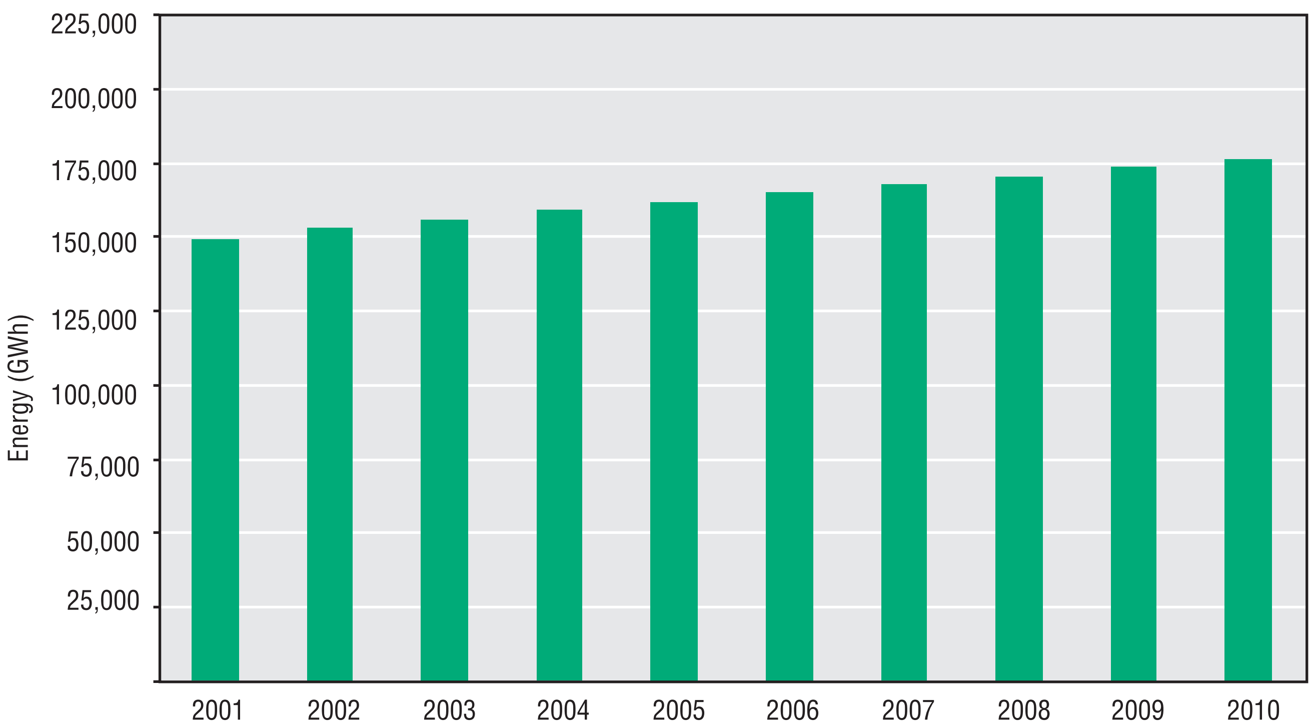


Figure 2.3: MAPP U.S. Regional Electric Capacity Situation, 2001-2010

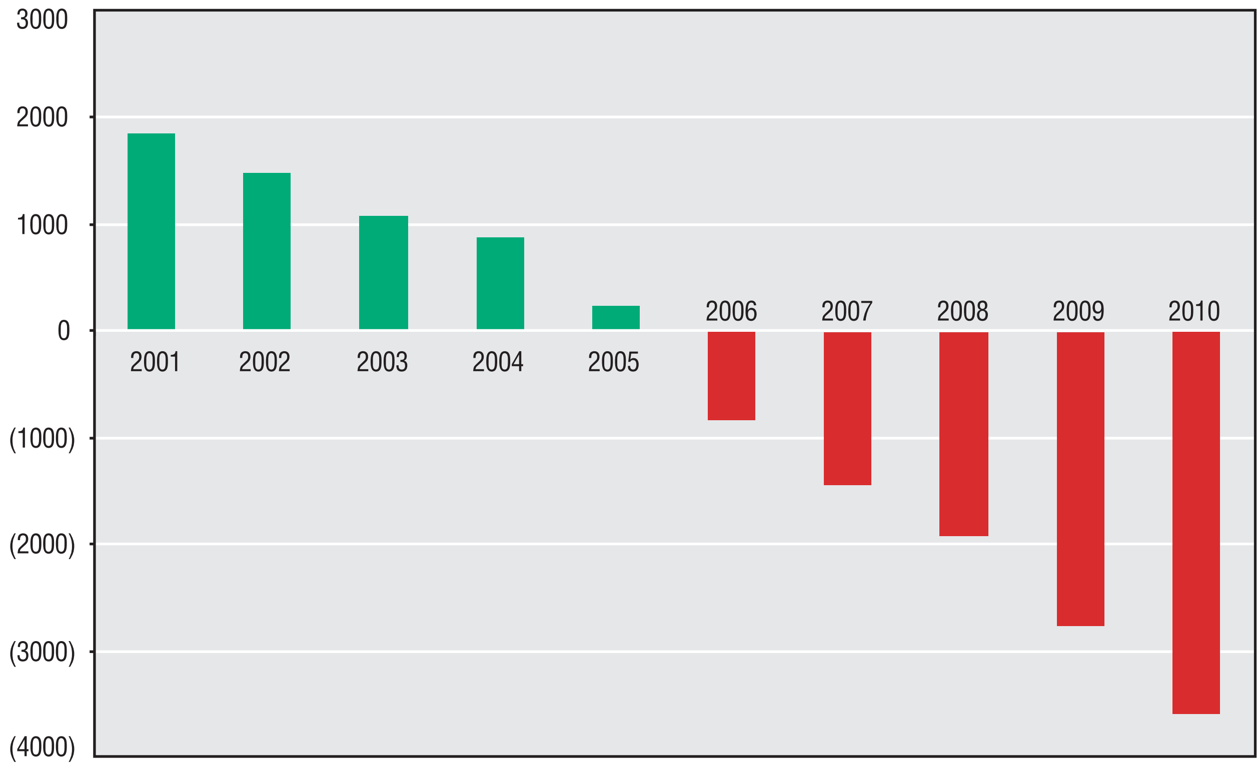


Figure 2.4: Major Minnesota Utility Electric Energy Situation, 2001-2010

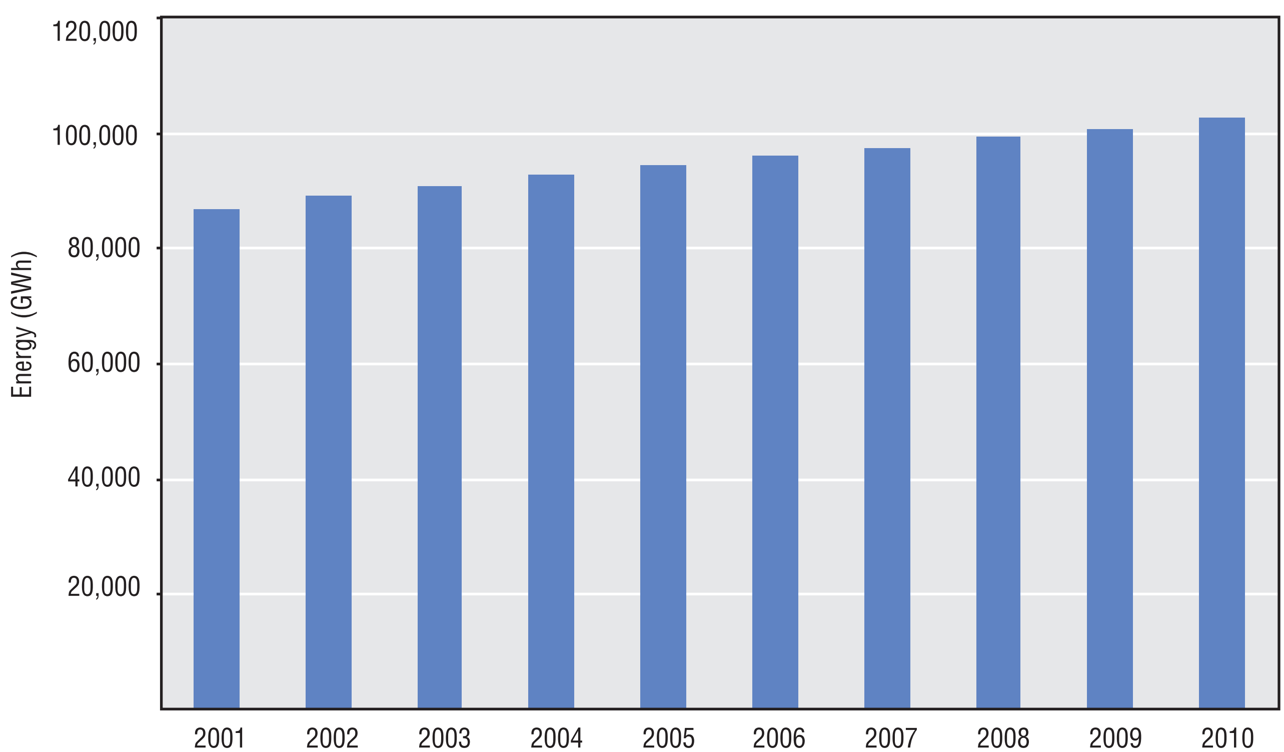


Figure 2.5: Major Minnesota Utility Electric Capacity Deficit, 2001-2010

Figure 2.6: Large Utility GrowthRates

Utility	Energy Growth Rate (2001-2010)
Missouri River	4.0%
Rochester	3.6%
Great River (CP & UPA)	2.7%
Minnkota	2.5%
SMMPA	2.3%
MMPA	2.2%
Xcel Energy	2.0%
Gen~Sys (Dairyland)	1.8%
Basin/East River/L&O	1.3%
Otter Tail Power	1.0%
Minnesota Power	0.8%

Figure 2.7: Xcel Electric Capacity Forecast, 2001-2010

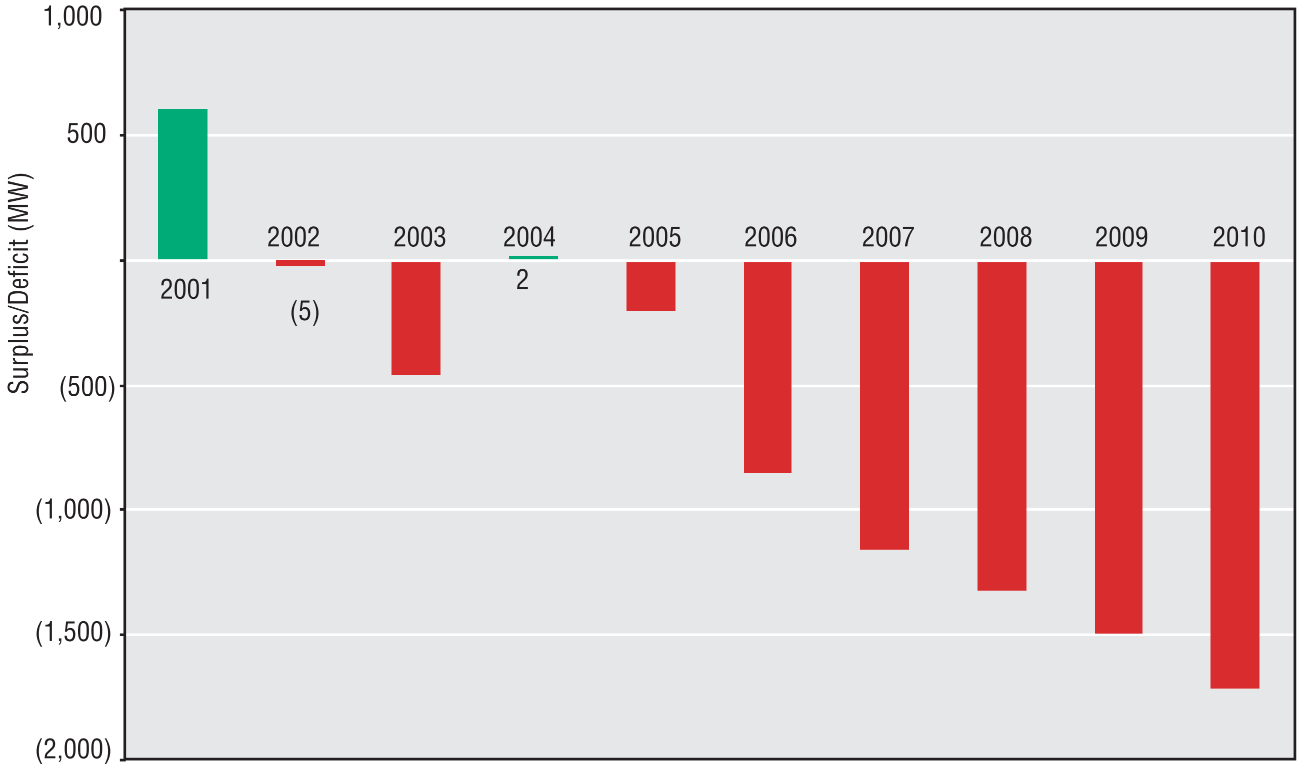


Figure 2.8: Large Utilities with Electric Capacity Deficits Over 100MW, 2001-2010

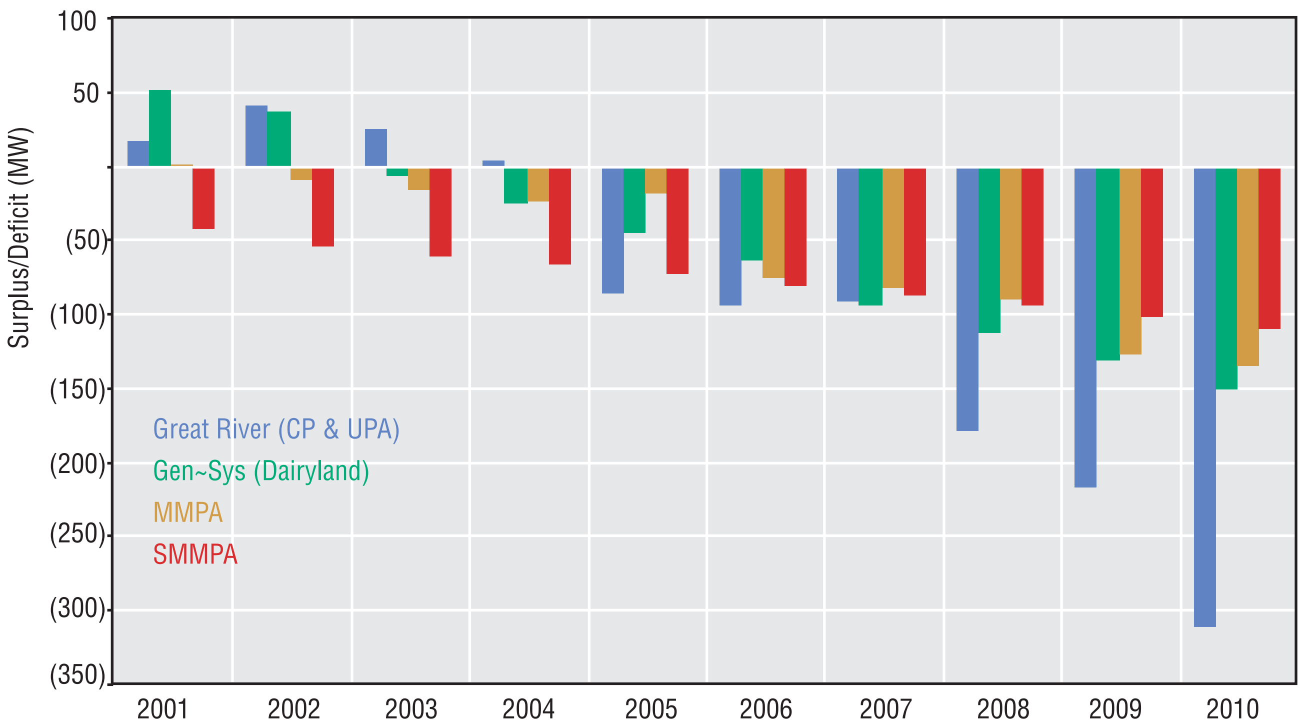


Figure 2.9: Large Utilities Without Major Electric Capacity Deficits, 2001-2010

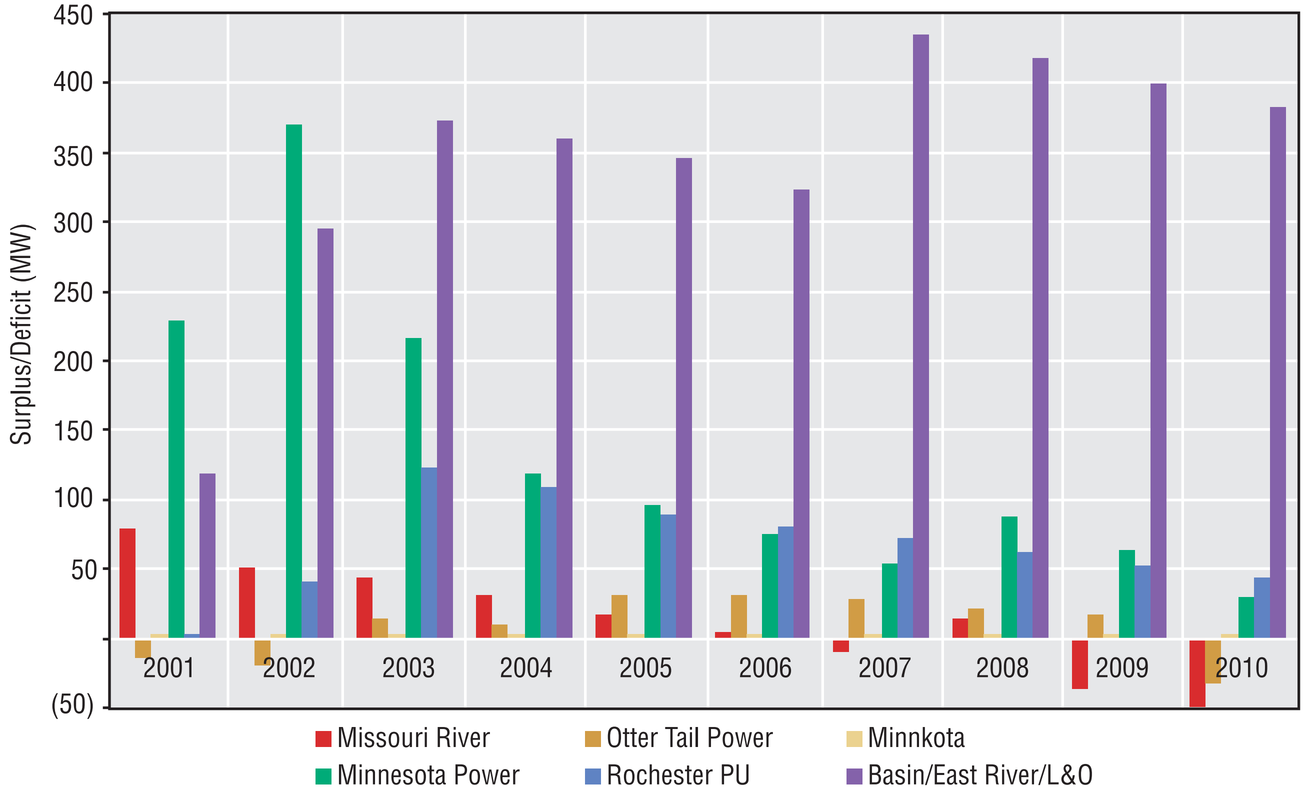


Figure 2.10: Short-Term IRP Forecasts, 2001-2006							
Utility	Year IRP filed	2001	2002	2003	2004	2005	2006
Alliant	1999	5	(10)	(28)	(51)	(99)	(123)
Dairyland	2000	(20)	(41)	(87)	(106)	(129)	(152)
Great River Energy	2001	(227)	(224)	(251)	(293)	(394)	(370)
Minnesota Power	1999	249	59	49	38	26	-
Minnkota	1998	65	59	49	45	41	36
Missouri River	2001	-	-	-	-	(12)	(31)
Otter Tail Power	1999	(81)	(92)	(96)	(100)	(74)	(79)
SMMPA	2000	(39)	(52)	(61)	(68)	(76)	(85)
Xcel Energy	2000	(212)	(376)	(422)	(373)	(526)	(1181)

Figure 2.11: Long-Term IRP Forecasts, 2007-2015									
Utility	2007	2008	2009	2010	2011	2012	2013	2014	2015
Alliant	(145)	(168)	(391)	(414)	(437)	(460)	(484)		
Dairyland									
Great River Energy	(261)	(360)	(463)	(520)	(536)	(640)	(745)	(853)	(962)
Minnesota Power	-	15	-	-	-	-	-		
Minnkota	32	27	22	17	13	8			
Missouri River	(46)	(60)	(76)	(90)	(110)	(124)	(139)	(155)	(169)
Otter Tail Power	(86)	(94)	(97)	(97)	(97)	(100)	(106)	(109)	
SMMPA	(93)	(101)	(110)	(118)	(126)	(134)	(143)	(151)	(158)
Xcel Energy	(1,468)	(1,633)	(1,853)	(2,026)	(2,198)	(2,360)	(2,515)	(2,675)	

Figure 2.12: IRP Supply Side Action Plan Summary (50MW or More)

Utility	Size (MW)	Type	Date
Otter Tail Power	50	PPA	2000
Dairyland	80	Peaking	2001
Xcel Energy	80	Wind	2002
Great River Energy	250	Peaking	2003
SMMPA	93	Peaking	2003
Xcel Energy	100-600	PPA	2003
Alliant Energy	154	Peaking	2005
Xcel Energy	up to 400	PPA	2006
Xcel Energy	up to 500	PPA	2007
Alliant Energy	538	Peaking	2008
Xcel Energy	up to 600	PPA	2008
Alliant Energy	430	Base	2009
Great River Energy	250	Base	2009
Alliant Energy	215	Base	2010
Alliant Energy	154	Peaking	2010
Otter Tail Power	78	Peaking	2010
Alliant Energy	430	Base	2011
Alliant Energy	215	Base	2012
Alliant Energy	76	Peaking	2012
Alliant Energy	215	Base	2014

NOTE: Alliant Energy is not a member of MAPP, and the vast majority of its customers are not in Minnesota.

Figure 2.13: Natural Gas Drilling Rig Counts, 1999-2000

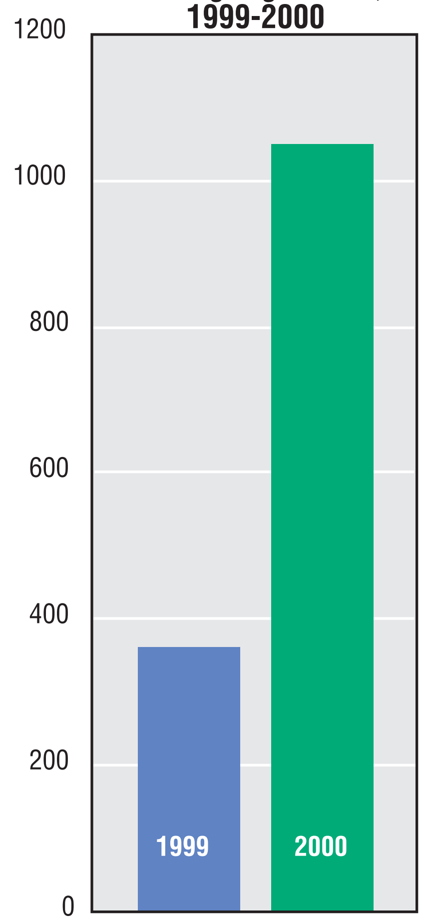


Figure 2.14: NYMEX Henry Hub Expiration Prices

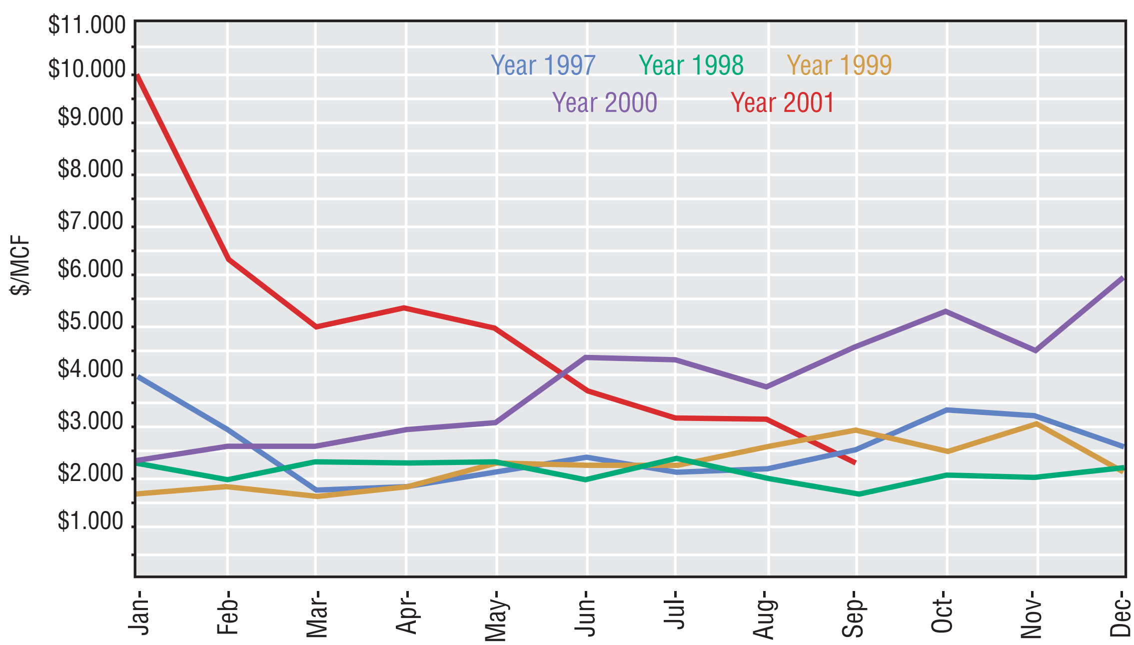


Figure 2.15: NYMEX Henry Hub Natural Gas Futures Contract Prices

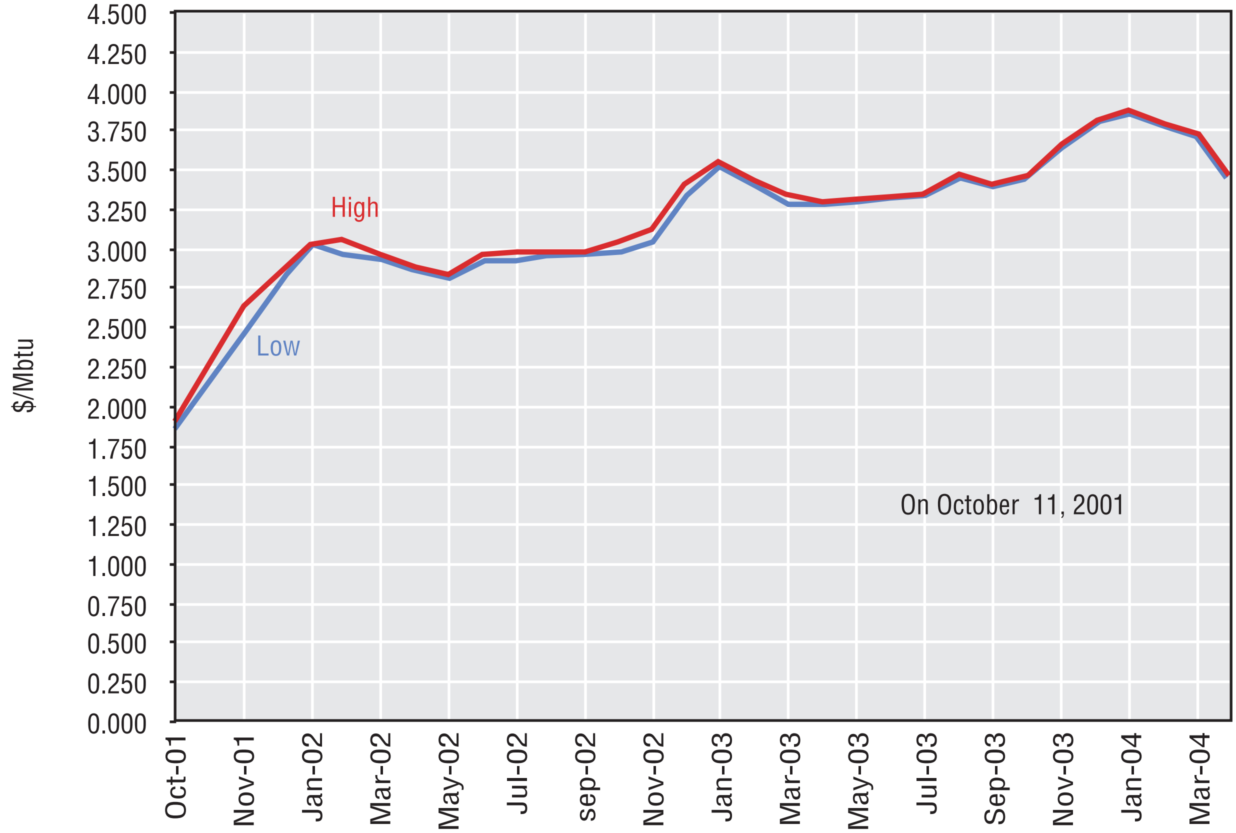


Figure 2.16: Projected Natural Gas Demand, 2000-2010 (lower 48 states)

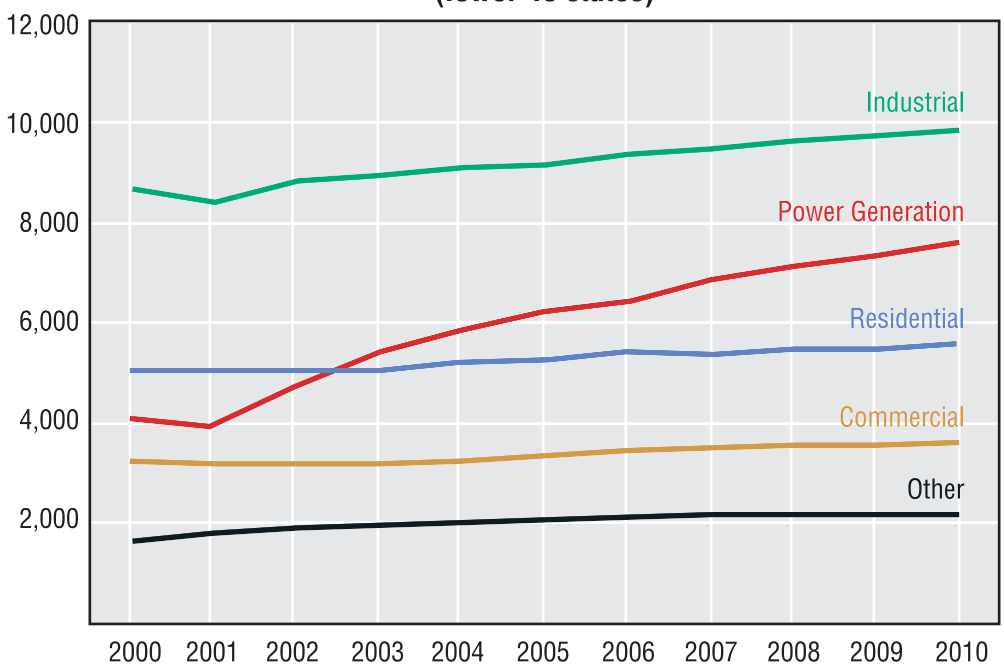


Figure 2.17: Relationship of Fuel Oil and Propane Prices to Crude Oil Price, 1994-2001

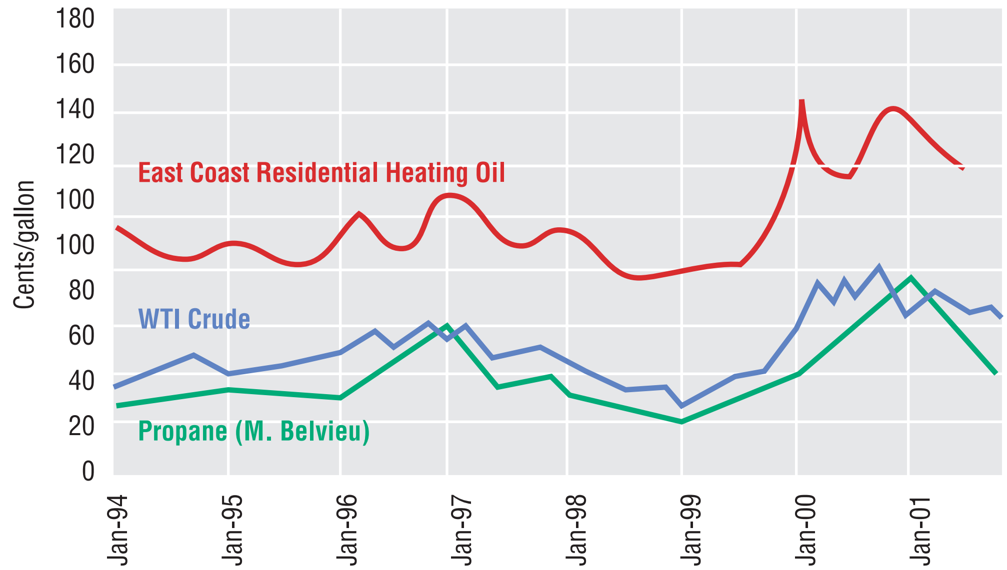


Figure 2.18: U.S. Distillate Fuel Oil Demand

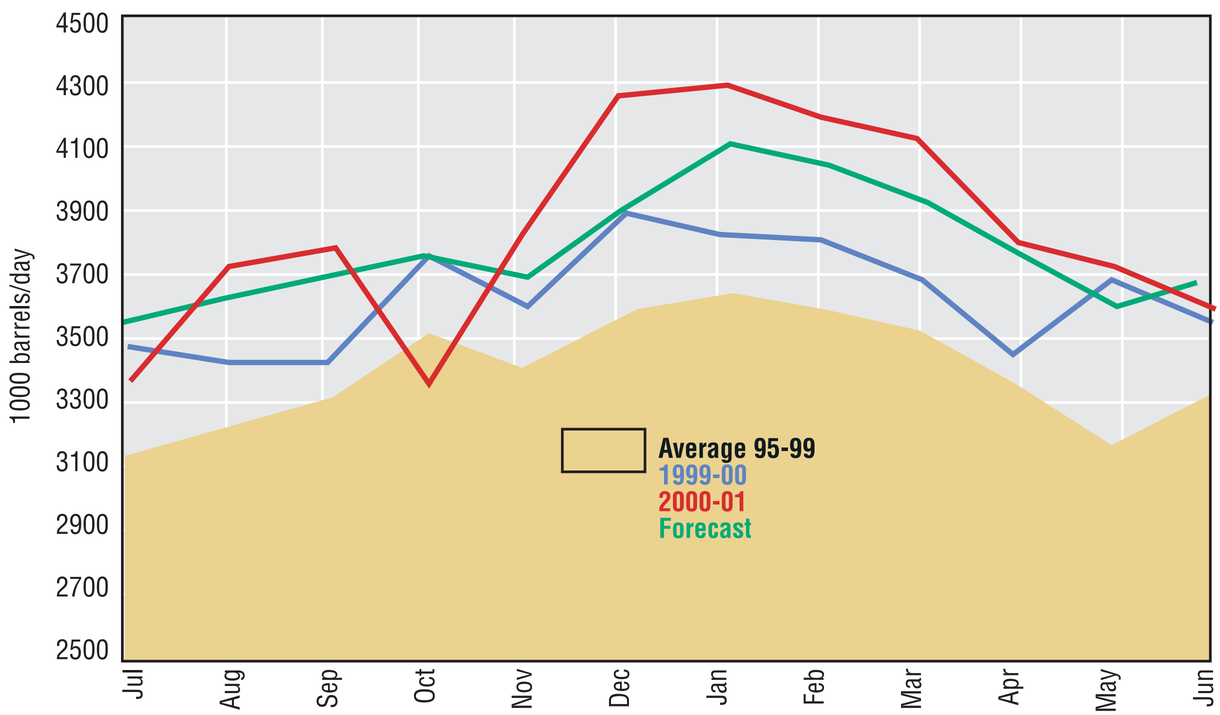


Figure 2.19: U.S. Propane Production

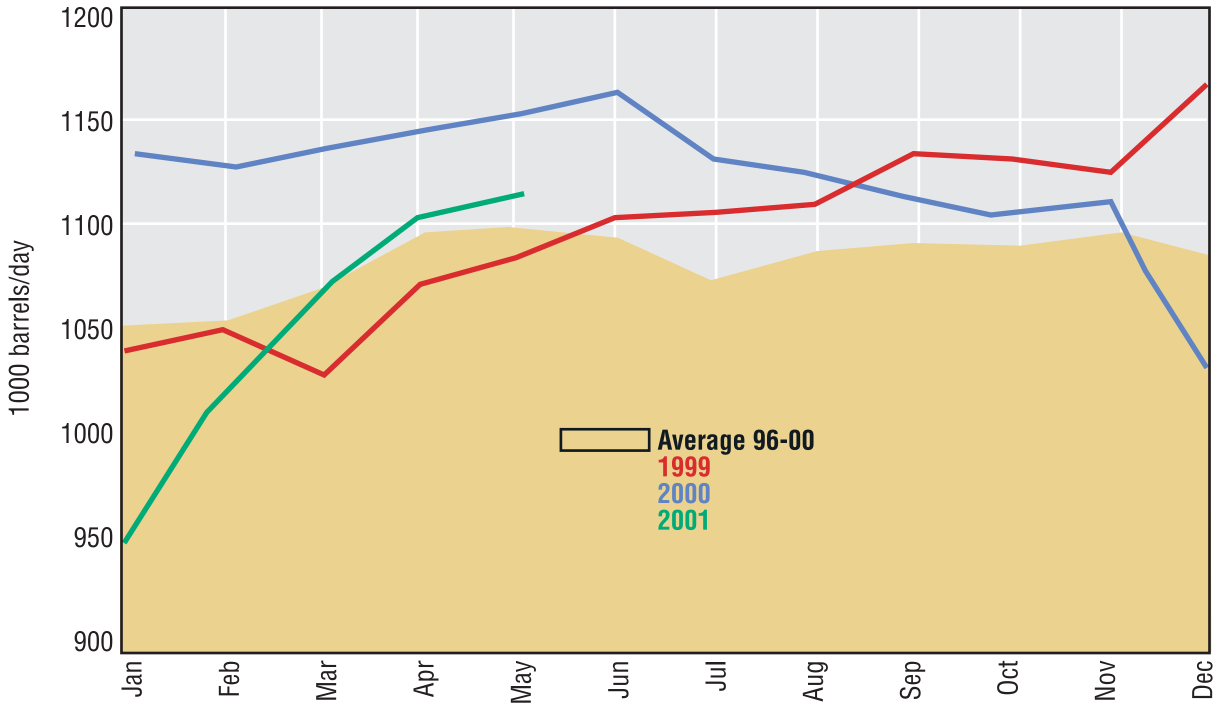
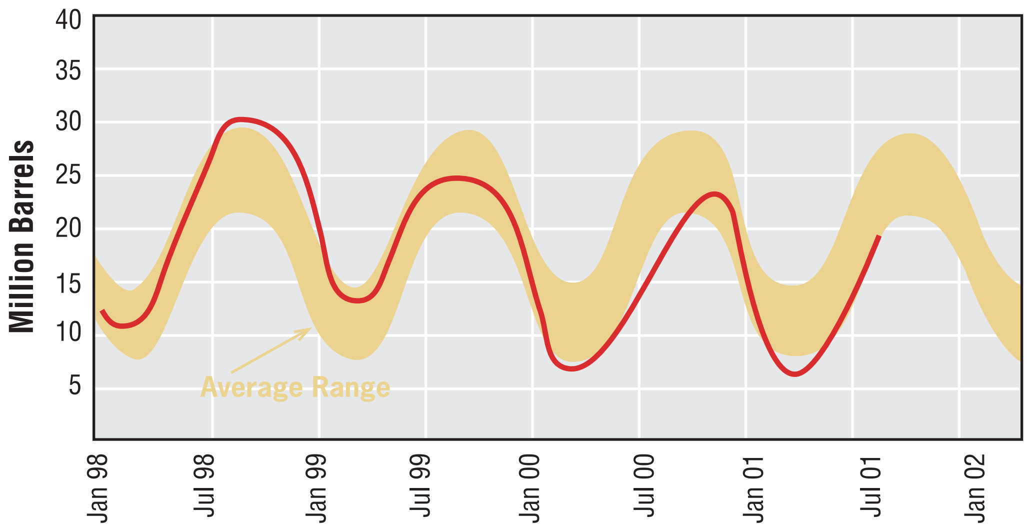


Figure 2.20: PAD District II Stocks
Midwest



CHAPTER THREE: STRATEGIES TO MEET ELECTRIC DEMAND

The first part of the chapter lists electric generation technologies and discusses their efficiencies, potential for and barriers to further deployment, costs to construct and operate new facilities, and environmental effects of each technology. No generation technology exists that either does not bring with it adverse economic or environmental effects or does not have significant other barriers to its greater deployment.

The second part of the chapter is an analysis of energy conservation, which is the only method of creating new capacity in the electricity system that has no adverse economic or environmental effects. This section will analyze the history of conservation programs and explore the potential for greater conservation in the future. It also explores the costs of conservation programs. This part is intended to satisfy the requirement in 2001 Minn. Laws, Ch. 212, Art. 9, Section 15 to provide an analysis of the existing Conservation Improvement Program and its future potential.

When thinking about future strategies to meet electric demand, it is helpful to first review the current system. Figure 3-1 shows the fuel inputs used to generate Minnesota's electricity in 2000.[32] Minnesotans consumed 62,532,000 megawatt hours of electricity in 2000, and spent $3.4 billion to purchase it. The largest environmental impact of electric generation is through its air emissions. In 1999 emissions included, for instance, 35,982,000 tons of greenhouse gases, 87,000 tons of nitrogen oxides, 95,000 tons of sulfur dioxide, and 0.8 ton of toxic mercury. Figure 3-2 shows that, when compared to coal, other electric generation sources contribute only a relatively small amount to these air pollutants.[33]

In the coal technology section we include a lengthy discussion of the environmental and potential health effects of existing generation plants in Minnesota that use coal technologies, the costs to reduce those effects, and potential impacts on utility rates for various levels of reduction. The detailed material on the environmental effects of coal technologies, and to a much lesser degree, natural gas and other combustible fuel technologies, is found in Appendix A. Most of Appendix A was prepared by Minnesota Pollution Control Agency (MPCA) staff. The rate impact material was prepared by a Department of Commerce financial analyst once the potential costs of control technologies at specific generating plants were developed by PCA staff.

The generation technology part will also articulate the range of efficiency a particular generation technology can achieve in converting the energy in its fuel to electricity. This concept is important because, nationally in 2000, about two-thirds of all energy

[32] Nationally, the fuel mix is 52 percent coal, 20 percent nuclear, 16 percent natural gas, 7 percent hydropower, 3 percent oil and 2 percent renewables. National Energy Policy, 1-6, May 2001.
[33] Vehicles, on- and off-road, are significant contributors of air pollutants, as discussed in Chapter 1. Vehicles also contribute significantly to greenhouse gas emissions.

used to generate electricity was lost, usually as heat, in the process of its conversion from fuel to electricity. Another 9 percent of electricity generated is lost in the process of transmission and distribution to customers.[34] Further losses are suffered, and energy wasted, if the end-user uses the electricity to power low efficiency machines, appliances and light bulbs. The review of generation technologies will show that efficiency factors vary within many categories of generation technology, and that there are differences within each category. Conservation programs address efficiency of use by retail customers of utilities. Chapter 4 will discuss efforts to improve the efficiency in the transmission of electricity.

Finally, Figure 3-3 shows projects by time, size and type, that are under construction, approved, or for which approval processes are underway, in Minnesota. These projects total 1,032 MW of capacity.[35]

[34] 2000 Annual Energy Review, EIA, at 217.

[35] In 2001, two gas peaking facilities, Lakefield Junction and Pleasant Valley, added 920 MW of peaking capacity to the system, reducing the Minnesota portion of the capacity deficit from about 3,000 MW to the 2,000 MW discussed in Chapter 2.

TECHNOLOGIES TO GENERATE ELECTRICITY

This section will discuss in turn each of several technologies that are available to generate electricity, starting with the one most predominant today: coal. Each part will discuss the efficiency, potential for and barriers to further deployment, cost to construct and operate new facilities, and environmental impacts of each type of electric generation technology.

COAL

Coal-fired power plants have been the predominant source of electricity in this country for the last century. Coal provides 75 percent of Minnesota's electricity. A coal-fired power plant burns coal in a boiler, which generates heat that turns water into steam that turns turbines to generate electricity. This is the basic operation of a pulverized coal boiler. Nearly all Minnesota coal plants utilize this technology. Because a new traditional coal-fired power plant is about 33 percent efficient in turning the energy in the coal into electricity and because the burning of coal creates significant air pollutant emissions, intensive research has been done to attempt to improve the efficiency of and reduce the emissions from, coal combustion.[36]

Two combustion technologies that exist to improve coal combustion performance are fluidized bed combustion and coal gasification. In fluidized bed combustion, the operating principle is to feed crushed fuel into the boiler and burn it with the use of a bed that consists of sand or fuel ash. Combustion air is introduced to the boiler: the primary air flows upwards and fluidizes the bed while the secondary air is injected above the bed. This method burns coal in a bed that transfers heat to water, generating steam. This steam is pressurized and used to turn a turbine shaft, which subsequently drives an electric generator. Limestone is added to the bed to reduce the amount of acid gases released during combustion.[37] Fluidized bed combustion technology is about 42 percent efficient and has been commercially available for many years.

In coal gasification, a gasifier converts carbon-base feedstock into large gaseous components by applying heat under pressure in the presence of steam. This process produces carbon monoxide and hydrogen, referred to as "syngas." The clean syngas remaining after pollutant separation is used to fuel a combustion turbine.[38] This technology may become commercially viable. It is being demonstrated in pilot projects. Coal gasification is about 38 percent efficient.

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[36] Existing Minnesota traditional coal-fired power plants are, on average, 38 percent efficient. The slightly higher efficiency reflects the absence of pollution control equipment that is required for a new plant.
[37] Sources: Docket No. IP4/CN-01-1306 (Rapids Power).
[38] Source: National Energy Technology Laboratory, DOE, www.fetc.doe.gov/products/power1/gasificationframeset.htm

Coal is the most abundant fossil fuel resource in the United States, with major deposits in the eastern states such as West Virginia and Kentucky, and in the western states of Wyoming, Montana, Colorado and Utah. Coal prices historically have been very stable, peaking in the energy crisis period in the mid-1970s at $48.34/ton and gradually falling to a price of $16.00/ton in 1999.[39] Because western coal is less expensive to mine and has up to 85 percent lower sulfur emissions when burned than eastern coal, coal production is increasing in the west and staying level or declining slightly in the east.[40] Minemouth coal prices are expected to continue to fall due to increasing productivity. Transportation costs are projected to decline slightly, but are heavily influenced by fuel prices.[41]

While cost and supply of the fuel are not barriers to constructing and operating new coal fired power plants, the cost of a new coal plant is a barrier. Figure 3-4 shows just the cost to construct a new coal facility. Those costs range from $920 to $1,400 per kilowatt of nameplate capacity (between one billion and one and a half billion dollars for a 1,000 megawatt plant). Fuel and operational costs add to those figures for the life of the facility.

By comparison, a new natural gas fired plant costs from $365 to $600 per kilowatt of nameplate capacity. Additionally emissions from a natural gas plant as compared with the best new coal plant per unit of output are about 20 times less for sulfur dioxide, about ten times less for nitrogen oxide, 2.5 times less for carbon dioxide, and 100% less for mercury. Natural gas also can be sized smaller without losing economies of scale. The result is that a natural gas plant is better able to be sited to take advantage of the heat produced, which increases the efficiency of the fuel, and to avoid costly upgrades to transmission systems. Of course, natural gas plants also have ongoing fuel and operational costs as well and are limited in where they may be sited due to pipeline locations. Fuel cost for natural gas has received a lot of attention since the huge price spike during the 2000-2001 heating season and, while prices are now low and predicted to remain so for the next two to three years, the increased volatility in the price of natural gas is of concern.

Another comparison is with wind energy, backed up with firm capacity from gas, coal, storage, or, eventually, fuel cells and similar technologies. Construction of commercial scale wind energy plants costs about $800 to $1,000 per kilowatt hour of nameplate capacity. Also, wind is the only presently commercially viable Minnesota energy resource that can provide electricity on a large scale without relying on resources that must come from outside the state. In addition, the fuel will cost the same 50 or 100 years from now as it costs today – $zero. Wind energy production emits no pollutants.

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[39] Annual Energy Review 2000, EIA, at 212. The price of coal when it peaked in the 1970s reflected the high price of its competing fuels such as natural gas and oil.

[40] Annual Energy Outlook 2001, EIA, at 92 and 94.

[41] Id. at 92 and 94.

Another cost consideration for new coal plants is the probability that future applicable environmental regulations will require decreasing air pollutant emission rates and decreasing total emissions. The energy planning horizon is long – a minimum of 10 to 15 years. Any new plant will likely operate 50 years or longer. These potential additional costs are unknown at this time, which adds an element of uncertainty in planning to construct a large new coal plant.

An additional important energy planning issue is what to do about air pollutant emissions from existing power plants. It is an energy planning issue because the level of overall emissions is such that it is difficult to build new plants that will add significant emissions without somehow reducing emissions at existing plants. The existing coal plants are not regulated by the most stringent Clean Air Act standards because they were built before the standards were adopted. There is substantial opportunity to reduce emissions at existing plants at reasonable cost.

2001 Minn. Laws, Ch. 212, Art. 7, Sec. 35 requires the Department of Commerce (DOC), in this report and the updated report due in 2002, to "identify important trends and issues in energy … environmental effects." Further, the legislation requires DOC to "address, among other issues: … (6) the environmental effects of energy consumption, including an analysis of the costs associated with reducing those effects; …." In preparing the report, DOC is to "consult with other state agencies, including … the pollution control agency …."

The following discussion summarizes, and relates to energy planning, the material contained in Appendix A. The appendix was prepared by Pollution Control Agency staff.

Addressing Environmental Impacts of Existing Facilities

Emissions

This part will briefly discuss:

- emissions of pollutants from existing Minnesota power plants;
- their effects on the human health and the environment;
- methods and costs of reducing these emissions; and
- the potential impact on electric rates paid by consumers of various emission reduction methods.

One of the most difficult issues in future energy supply is what to do about existing power plants at a time when we need to be building more. Existing plants in Minnesota are a significant source, and for some pollutants, the major source of harmful air emissions. Overall emissions of air pollutants from power production needs to be held steady and then decreased over time. The trend has been in the opposite direction.

Electric generation in Minnesota is primarily coal-fired. Figure 3-5 shows the total tons of emissions, by pollutant, from electric generation and electric generation's share of total emissions for each pollutant. The emissions of concern are nitrogen oxides (NO_x), sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), lead, mercury, and greenhouse gases (mostly carbon dioxide, CO_2).

Of the 350 electric generators in the state, five are regulated by New Source Performance Standards (NSPS) under the federal Clean Air Act. Of those five, four are regulated under old NSPS in force when they were approved for construction or substantial reconstruction (one each in 1976 and 1979, and two in 1986). The only generator regulated under current NSPS is the natural gas plant, LSG Cottage Grove, built in 1998. Figure 3-6 lists the largest plants. Fifteen of the largest generators are not subject to any NSPS because they were constructed before the standards were adopted.

Figure 3-7 shows emissions of four pollutants per unit of production at the largest power plants. By comparison, the present performance standard at new or modified coal fired power plants for NO_x is about 0.001 lb. per kWh. The lowest emitting large Minnesota coal plants, emit four times that much and the highest emitting plants emit 11 times that much. The present performance standard at new or modified coal plants for SO_2 is about 0.001 to 0.002 lbs. per kWh.. The lowest emitting large coal plant, emits 1.5 to 3 times that amount and the highest emitting plant emits 10.5 to 21 times that amount.

No commercially available control technologies exist yet for mercury or CO_2. CO_2 emissions can be offset through tree planting and other forms of carbon sequestration. Depending on the type of fuel used and the control technology applied, however, NO_x and SO_2 emissions can be reduced by 30 to 85% using readily available equipment and methods.

Since 1986, emissions from electric generation of SO_2, NO_x and greenhouse gases have either dramatically or steadily increased. Coal is responsible for all or nearly all of these emissions. The spike in mercury emissions from solid waste incinerators that occurred in the late 1980s appears to be over due to requirements for stringent mercury input and emission controls at incinerators. See Figures A-5 to A-8 and accompanying text in Appendix A. A steep decrease in SO_2 emissions from 1985 to 1986 was due to increased use of lower sulfur western coal. Those emissions overall, however, are now climbing back up to 1985 levels.

Health and Environmental Impacts of Emissions

The emissions of concern are "of concern" for many reasons. Many of them directly impose health risks on humans. Many also negatively affect the natural environment and directly disrupt ecosystems, impose health risks on plants and animals, and therefore indirectly affect human health. The following is a summary of the known effects of the various emissions from electric generation plants. Appendix A presents a more thorough discussion of this material.

Particulate matter. Airborne particulate matter, especially very small or fine particulates like $PM_{2.5}$, pose health concerns. Power plants and other primarily combustion sources emit particulates.

Particulates are inhaled, lodge in the lungs, and tend to stay there. Correlations exist between particulates and increased deaths from heart disease and respiratory disease. Asthma attacks increase with an increase in particulate concentrations. In addition small particles are a major contributor to reductions in visibility.

Yearly average concentrations of particulates in the air in the Twin Cities range from 11 to 14 micrograms per cubic meter, which is well above concentrations found in scientific studies to affect human health. These concentrations are just slightly below federal Environmental Protection Agency (EPA) 1997 standards of a maximum yearly average of 15 micrograms per cubic meter. There is also an hourly standard. Both the yearly average and hourly standard will be relevant in 2002 when the EPA will begin to designate cities who violate the standards as nonattainment areas under the Clean Air Act. Nonattainment designation results in new requirements to reduce the emissions. The Twin Cities area is just under these maximum standards at present.

Ozone. Ground level ozone is formed when NO_x and volatile organic compounds (VOCs) react chemically in sunlight. NO_x, as discussed above, is emitted in very large amounts by power plants. Ozone, which provides protection from the sun in the upper atmosphere, when it occurs at ground level and is inhaled, can result in respiratory irritation, coughing, chest tightness, lung injury, asthma aggravation, and increased susceptibility to respiratory infections. At most risk at people who are active in the outdoors and people with respiratory problems.

Ozone pollution occurs mostly in hot, sunny weather. For the first time since the mid-1970's, four air advisories were issued for the Twin Cities in the summer of 2001 due to high levels of ozone. The metropolitan area is very close to violating ozone standards too.

Mercury. Mercury, a heavy metal, is present in coal. When the coal is burned, the mercury is emitted. It can travel long distances before dropping back to earth. Many Minnesota lakes, including very remote lakes, are experiencing big increases in mercury pollution in its most toxic form, methyl mercury. A lot of this mercury arrives from sources outside of Minnesota and Minnesota's emissions of mercury often travel to other states and countries.

Methyl mercury is a nerve toxin. It destroys nerves resulting in, in larger doses, brain disfunction and death. Methyl mercury in lakes is taken up by plant life and fish and on up the food chain either to larger mammals or to humans. Fetuses and children are especially susceptible to health effects from very small doses of mercury.

Many Minnesota lakes carry fish consumption advisories, especially for children and pregnant women because of the potential for mercury poisoning.

Global climate change. Global warming results from the accumulation in the atmosphere of very long-lived gases, called greenhouse gases, that act to absorb radiation, trapping it in the lower atmosphere. The primary greenhouse gas is carbon dioxide CO_2. About 99% of the greenhouse gas emitted during coal, oil, or natural gas combustion to generate electricity is CO_2, the remainder is mostly nitrous oxide.

The trapped radiation due to the presence of the gases, which persist in the atmosphere for hundreds of years once they are there, leads to rising surface and atmospheric temperatures around the globe. As a result, virtually every component of what we know as weather and climate will change.

Recently, the UN Intergovernmental Panel on Climate Change concluded that, accounting for uncertainties, mean global surface temperature will rise 1.4 to 5.8 degrees Celsius over the next 100 years. An earlier study by the US National Academy of Sciences concluded that mean global surface temperature will increase 1.5 to 4.5 degrees Celsius upon a doubling of atmospheric levels of CO_2, which most scientists anticipate within the next century. As a rule of thumb, each one degree Celsius increase in the mean temperature in the Northern Hemisphere is associated with a northward displacement of climatic and ecological regions of about 100 miles. Few ecological systems in Minnesota will survive this warming without significant disruption. See Appendix A for a more thorough exploration of the science and effects of global climate change.

Acid Rain. Sodium dioxide (SO_2) and nitrogen oxide (NO_x) emitted to the air are the primary causes of acid rain. In addition, nitrogen contributes to oxygen depletion of water bodies. Power plants, as discussed above, are major emitters of these pollutants.

Acid rain acidifies lakes and streams, causing often permanent damage and death to water creatures and plants, trees, and soils. While Minnesota lakes and soils appear to be fairly well-buffered from the effects of acid rain, the northeastern part of the United States is not so lucky. There were significant reductions of SO_2 in Minnesota when power plants switched to lower sulfur coal in the late 1980s, although emissions in

Minnesota are creeping back up to mid 1980s levels. Recent studies have concluded that an additional reduction of 80 percent in emission of these pollutants may be necessary for partial recovery of fish and trees over the next 50 years.

Conclusion. Power plants that utilize fuel combustion technologies, particularly coal-fired power plants (the source of 75% of the electricity consumed in Minnesota), are major contributors to environmental and health problems from air pollution. Figure 3-8 summarizes these pollutants and their effects.

Probably the most critical near term air pollution issue for Minnesota is ozone. With ground level ozone exceeding Clean Air Act standards, Minnesota may be forced to reduce emissions of nitrogen oxides and other pollutants that contribute to ozone formulation.

In addition to the impacts from air pollutants, coal combustion results in large amounts of ash containing toxic metals that requires specialized disposal. Large volumes of water drawn from rivers and other natural sources is used for steam turbines and/or for cooling and then returned at a higher temperature. In addition, the mining, transportation, and storage of coal also have adverse environmental effects. Heat is given off in the process of turning fuel into electricity that, in most cases, is wasted rather than captured and used.

The Future of Emissions from Electric Generation

Since 1983, the SherCo 3 unit is the only new coal-fired generator added in Minnesota. The increases in emissions from electric generation are due mostly to increased utilization rates at existing plants, many of which are more than 40 years old. Figure A-9 and accompanying text in Appendix A show the increases in utilization rates.

There likely will be some further increase in utilization of existing plants. Increasing the overall capacity factors at these facilities by 5% or slightly more may be achievable. In aggregate, Minnesota utilities forecast, in their approved integrated resource plans (IRPs), an increase in coal throughput of about 2.5 million tons between 1999 and 2010.

In addition, new electric generation facilities will be added to meet the growing demand for electricity in Minnesota. In the short term, a number of facilities are proposed and in the process of receiving regulatory approvals or are under construction. Figure 3-9 lists these facilities and their additional contributions to emissions.

Costs of Reducing Emissions

At the same time that emissions are increasing from electric generation in Minnesota, federal regulation of the power production sector is likely to increase. Power plants across the nation must reduce emissions under some existing regulations and are likely to be required to do even deeper reductions in emissions in the future. See Appendix A for a detailed discussion of current and potential future regulations.

During the 1990s Minnesota power plant owners did reduce SO_2 and NO_x at a few plants to meet the requirements of the Clean Air Act Amendments of 1990. They did so without much in the way of equipment additions or the application of control technologies but by switching to lower sulfur coal for SO_2 and making modifications to a few plants for NO_x. Because they have not made major modifications to the existing plants for the most part, there is substantial potential for reducing emissions at these plants.

The pollutants for which the most available and tested control technologies exist are SO_2 and NO_x. Minnesota Pollution Control Agency staff have identified various options for reducing these pollutants at five Minnesota power plants. These options would apply to plants similar to the five models identified. The staff then determined the most cost effective control technology for each facility, based on the facility's boiler technology. See Appendix A and Figures A-19 to A-24 for a detailed explanation of how MPCA staff determined the technologies and costs.

Department of Commerce staff then calculated the impact on residential rates of installing the identified emissions reduction technologies. As shown in Figures 3-10 and 3-11, the average residential rate impact for SO_2 controls ranges from \$3.59 to \$27.42 per year and for NO_x controls ranges from \$1.02 to \$7.87 per year. For any given household, if more than one of its utility's plants installed the control technology, the rate impact would be the total of the amount for each of that utility's facilities that is upgraded. These rate impacts would decrease if the upgrade also extended the life of a facility beyond its present expected plant operation period and the costs were depreciated over a longer time.

Utilities that install emission reduction technologies may now pass those costs directly through to ratepayers without going through a full rate case before the Minnesota Public Utilities Commission (MPUC). In 2001, the Legislature enacted an Emissions Reduction Rider that would allow direct pass-through to retail customers of the costs of the emissions reduction technologies. The portion of the costs attributable to electricity sold on the wholesale market cannot be recovered from the utility's retail customers. The MPUC would make the determination of what costs may be passed directly through to retail customers.

Policy Recommendations

If new electric generation plants are constructed in Minnesota that potentially increase overall emissions of air pollutants, emissions at existing plants should be reduced by at least as much as the new emissions. Fortunately, there are readily available emissions reduction technologies for existing plants that do not overburden ratepayers with high costs. Additionally, switching from coal to natural gas, which is being done at part of Xcel Energy's Black Dog plant, is an option that utilities ought to explore. Finally, there may be older, smaller plants that emit a disproportionate amount of air pollutants that ought to be closed. All of these options ought to be explored in each utility's Integrated Resource Plan as it is regularly updated.

As part of a negotiated settlement with interested parties in its recent merger, Xcel Energy agreed to study repowering options at three of its plants, King, High Bridge, and Riverside. Through a separate agreement during the 2001 legislative session, Xcel Energy agreed to study other emission control options at these plants. The cost figures above will in all likelihood apply to those plants. The legislature could require all utilities to prepare similar analyses for their plants. Another possibility is to authorize the MPUC to require utilities to install emissions control equipment that is cost effective and would significantly reduce emissions, after the utilities' studies are complete.

NATURAL GAS

Natural gas has been the predominant fuel for new electric generating plants in the United States for the last few years, due to a combination of the relatively low price of natural gas as a fuel in the summer and the favorable air emission characteristics of a natural gas plant compared to generating electricity using coal as shown in Figure 3-4. In addition, this year, two natural gas plants were brought on line in Minnesota, located where natural gas pipelines and high voltage transmission lines are in close proximity. This allowed for efficient delivery of gas to the plants and for access of the plants to the electric transmission system. The Lakefield Junction project, which has a capacity of 486 MW, cost approximately $375 per kilowatt. Similarly, the Pleasant Valley plant, with a capacity of 434 MW, was built at a cost of approximately $436 per kilowatt. These facilities have added over 900 MW of peaking capacity to the grid in Minnesota, with little or no public controversy associated with their construction.

Another kind of natural gas plant project is the decision by Xcel Energy to repower Units 1 and 2 of its Black Dog electric generating plant in Burnsville with gas-fired generating technology. This project will convert coal-fired to gas-fired technology, while at the same time increasing the capacity of both units a total of 114 megawatts. This addition to Xcel's summer generation capability is expected to be available by the summer of 2002. The cost of the repowering was estimated to be approximately $600 per kilowatt. Xcel Energy, under the terms of one of its merger settlements, has studied the feasibility of converting some of the units at St. Paul's High Bridge plant and at the Riverside generating station in Minneapolis to natural gas as well.

A third type of natural gas project is to use a natural gas peaking unit in conjunction with wind power to be able to deliver baseload firm power to a utility system. In Xcel Energy's recent all-source bidding process, a project by Navitas / NAE was the lowest cost proposal and won the bid with a combination of 50 MW of wind power and 250 MW of natural gas-fired generation.

Natural gas-fired generation plants are generally peaking or intermediate plants, not constant-burning baseload generation. Minnesota's ability to add gas-fired generation to meet the state's capacity needs relates to the capacity of natural gas pipelines to deliver enough natural gas to fuel additional power plants. For the southern portion of the state where electricity demand peaks in the summer, the need to transport natural gas does not compete with the priority use of the pipelines to transport natural gas to the state for home heating in the winter. With the addition of gas-fired generating plants the system does, however, require different adjustments, depending on location. Whenever the state reaches the point where additional pipeline capacity is needed, it can be assumed that the pipeline would cost between one to two million dollars per mile to construct.

As expected, Northern Natural's pipeline is configured to supply all of its customers along its line, including the entire Twin Cities area, with natural gas in the winter when the temperatures dip to their lowest points. With this configuration, it is not surprising that Northern Natural has space available in its pipeline for use outside of peak winter heating season. Thus, the opportunity arises to use natural gas to fuel electric peak-shaving plants to handle summer peak-cooling usage. Considering the relatively lower environmental emissions created by burning natural gas, and its ability to "fire up" peaking plants quickly and easily, natural gas is a prime fuel for handling fluctuating peak summer electric use.

However, natural gas, and Northern Natural's pipeline configuration, also has its limitations when it comes to providing natural gas for summer electric peaking use. All pipelines are built by connecting several different sizes and types of pipe segments to take care of the needs of each specific area it serves. Many times those areas change functions or grow (i.e., farm fields become housing developments) and the "old" pipeline configuration does not meet all of the needs of the new function. This creates constraints or "bottlenecks", not only on that particular segment of pipeline but all of the pipeline segments attached on the "downstream" side of the constrained pipe.

Building a natural gas-fired electric peak shaving station on a pipeline is another example of a function change for that pipeline segment as well as all of the attached downstream pipeline segments. In fact, this change of function, many times, is rather dramatic as most electric peak-shaving stations are sited in rural or semi-rural areas and, as such, pipeline segments are built to respond to rural or semi-rural residential or small commercial usage (in Northern Natural pipeline's case, that would equate to fairly modest, winter-peaking usage). When a peak shaving station is built, the usage on that pipeline segment changes dramatically as, all of a sudden, very large amounts of gas will be used at that one location sporadically during the summer. Conceivably, this could cause constraints on the pipeline and impact reliability for all customers downstream of the peak-shaving plant. In many cases, however, actions can be taken to mitigate any reliability risk for customers. Such actions could include building another pipeline right beside the first pipeline and connecting the ends (commonly known as "looping" a pipeline) or increasing the amount of natural gas pressure (compression) in the pipeline in order to move more gas through that pipeline segment. All of these limitations and mitigation options are carefully considered and studied during the permitting process for the peak shaving plant to ensure continuing reliable natural gas service for all (new and existing) customers on that pipeline segment.

Aside from the physical constraints mentioned above, there are also issues that must be considered with the price of natural gas. Since the late 1970s, the price of natural gas has not been regulated by either the federal or state governments. Also, in the early 1990s, natural gas became a "tradable" commodity on the New York Mercantile Exchange. As such, the price of natural gas, like prices of other petroleum products, fluctuates constantly in reaction to various current and expected market forces both here and around the world. These market forces may pertain to the current or predicted supply of natural gas available to the market, in that an oversupply would tend to decrease prices and an shortage of supply would tend to increase prices.

Differing demands for natural gas also impact markets and prices. For example, natural gas demands fluctuate depending on current and predicted weather (and the difference between predicted and actual weather patterns), evolving changes in gas usage (using more gas for electric peak shaving is an example) and the general economy and its overall productivity (and the gas needed to fuel that productivity). Supply and demand market forces are constantly changing, both in tandem and independently, to create a dynamic market environment in which natural gas prices fluctuate constantly.

This instability in natural gas prices can be mitigated by purchasing fixed-price contracts for gas or by using other financial instruments to counteract changing prices. However, these price-leveling options come with a measure of cost in a couple of ways. First, each financial instrument has a price tag attached to it. Also, depending on market price changes, the price "locked in" with the financial instrument may lock in a price higher than the variable market price at the time of usage. All of these cost factors must be carefully considered in choosing price stabilizing products to secure the fuel supply for natural gas plants.

The negative environmental effects of using natural gas to make electricity are substantially less than for coal. This is one of the reasons that most new electric generation in the nation uses natural gas. The relative "cleanness" of natural gas as a fuel contributes to the lower costs of building natural gas generating plants.

Additionally, gas is a much more efficient fuel than coal. A new conventional pulverized coal steam turbine is about 33% efficient in taking the energy in coal and turning it into electric energy. The most efficient coal technology is about 42% efficient. A natural gas combined cycle generator is about 55% efficient and if the heat is captured and utilized, efficiencies of ?% can be achieved.

Natural gas has very little sulfur compared to coal. A conventional new coal plant emits about 30 times more SO_2 than a combined cycle gas plant for the same amount of electricity generated. "Clean coal" technologies, as noted in Figure 3-4, do not reduce this gap very much.

Natural gas combustion does emit nitrogen oxide. A conventional new coal plant emits about 14.5 times more NO_x than a combined cycle gas plant for the same amount of electricity generated. Again the "clean coal" technologies only marginally reduce this disparity.

All carbon based fuels emit carbons, notably carbon dioxide, when burned, including natural gas. For the same amount of electricity generated, a conventional new coal plant emits three times more CO_2 than a gas plant. While the carbon content of similar amounts of coal and gas may be about the same, it take a lot less gas to make the same amount of electricity because of its higher efficiency in turning the energy in the fuel in o electric energy.

While there are barriers to deployment of lots of natural gas fired power plants in Minnesota, the environmental superiority of the fuel and its ability to be turned off and on rapidly, as well as its lower costs make gas an attractive fuel for electricity at least for the short term, in strategic locations to take advantage of summer availability, and as back up for wind energy when the wind does not blow on hot summer days.

NUCLEAR

Approximately 20 percent of the electricity consumed in Minnesota is generated from nuclear power. Nuclear power accounts for 36 percent of Xcel Energy's generating capacity. This energy is generated from the nuclear plant located in Monticello (545 megawatts) and the two nuclear reactors located at Prairie Island (1,027 megawatts).

In a nuclear power plant, uranium atoms are split, causing a chain reaction called nuclear fission. The reaction is kept under control with control rods. The reaction generates heat that heats water. The hot water generates steam that turns turbines to produce electricity.

The Monticello plant began operations in 1970 and is licensed to operate until 2010. Currently, the Monticello plant has sufficient arrangements to handle the spent nuclear waste produced in plant operations through the end of its license period. The Prairie Island nuclear plant began commercial operation in 1973 and 1974, with Unit 1's license expiring in 2013 and Unit 2's license expiring in 2014. The Prairie Island plant does not, however, have authorization to dispose of enough spent nuclear waste to be able to run through its licensed life. Under current Minnesota Statutes, which limit the storage of spent nuclear waste in dry casks at the plant site, the Prairie Island plant would need to shut down in 2007. The future of any further storage or disposal of spent nuclear fuel on the Prairie Island site is subject to a high level of public scrutiny and controversy. This report does not undertake to describe the details or options available in that debate.

If there is no increase in the number of dry casks that the legislature allows to be stored at Prairie Island, and if there is not developed by 2007 a site where spent nuclear fuel could be shipped for disposal, the Prairie Island plant will shut down in 2007. To prepare for that eventuality, the PUC has instructed Xcel Energy to conduct a bidding process to replace the power produced by the Prairie Island plant. This bid is for a contingency of 1,070 megawatts of electrical power. The bidding process should be completed in the fall of 2002. A successful bid will provide information about what the costs are for Minnesota ratepayers to replace the power provided by Prairie Island after 2007. Also, the plant will be fully depreciated in 2007 and, by that date, the fund to decommission the plant will be fully funded.

Due to the substantial public controversy and difficult trade-offs involved in construction of a nuclear plant, the Department does not expect a proposal for a new nuclear plant in Minnesota during the time horizon of this planning report. Nuclear plants, due to the need for redundant systems to ensure safety, are very capital-intensive to build. Once the plant is built, however, nuclear power plants generally offer relatively low marginal operating costs to produce energy. A new nuclear power plant would cost approximately $2,188 per kilowatt. This figure must be treated as an estimate, because no new nuclear power plant has been ordered in the United States since 1978.

Electricity produced by nuclear power plants results in the production of high-level radioactive waste for long-term disposal. The viability of any new nuclear plant would also depend on having a successful strategy for permanent disposal of spent nuclear fuel, which is a hazardous waste that must be sequestered from the environment for 250,000 years from the time it is generated. There is also a slight potential for the accidental release of radioactivity. Human exposure to radioactivity can have short-term effects in very high doses, and long-term chronic effects, such as increased cancer incidence, for low-level exposure. In addition, waters needed for cooling reactors are often discharged back into natural water bodies creating thermal pollution of the water body. Nuclear power production does not emit any air pollutants.

HYDROPOWER

Hydroelectric power plants convert the potential energy in water pooled at a higher elevation into electricity by passing the water through a turbine and discharging it at a lower elevation. The water moving downhill turns the turbine, which is connected to an electric generator and thus produces electrical energy.

Hydropower projects are generally operated in a run-of-river peaking or storage mode. Run-of-river projects use the natural flow of the river and produce relatively little change in the stream channel and stream flow. A peaking project impounds and releases water when the energy is needed. A storage project extensively impounds and stores water during high-flow periods to augment the water available during low-flow periods, allowing the flow releases in power production to be more constant. Many projects can function in more than one of these modes.

Currently, there are approximately 22 hydroelectric generating stations in the state of Minnesota, producing slightly under 150 megawatts of capacity. Figure 3-31 lists the four largest projects; the rest of the projects are under four megawatts of capacity (the majority of those are under two megawatts). Out-of-state hydropower projects in Wisconsin and South Dakota that generate some electricity used in Minnesota include approximately 19 projects that have a total capacity of 255.6 megawatts.[42] Additionally, Minnesota imports 850 megawatts of hydropower from Manitoba Hydropower.

While the theoretical potential of hydropower development in the upper Midwest states amounts to approximately 2,500 megawatts over 471 sites, practical development of this capacity requires that the supporting infrastructure, such as transmission lines, site access and dam development, is either present or readily able to be developed. There is not a single site in Minnesota, Wisconsin, North Dakota and Iowa with more than 52 megawatts of potential capacity. South Dakota has three sites with more than 129 megawatts of potential capacity, but two of these sites are beyond the jurisdiction of the South Dakota PUC and a third one has no dam or power generating capacity built.[43]

The Canadian part of the MAPP region includes southern Manitoba and southern Saskatchewan. A total hydroelectric potential of over 4,000 megawatts has been calculated for Manitoba. However, the current transmission export capability from Manitoba to Minnesota is already fully used. Therefore, any new Canadian hydropower project would require a new transmission line to be run from Manitoba

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[42] Department of Commerce, Utility Data Book, Table 9 (1998).
[43] Docket No. CN-99-1815, Black Dog Repowering Project Environmental Report, at 24 (2000).

into Minnesota to carry the power. Also significant is the fact that the province of Manitoba needs to deal with internal issues regarding the environmental effect of flooding the amount of land needed to produce this power, and the impact of such plans on relations of the provincial government with Manitoba's native tribes.

The operation of a hydroelectric generating station is a well-developed technology and, therefore, the reliability of a plant is very high, except in periods where the presence of ice or sustained drought might reduce the availability of water to turn the turbines. The overall efficiency of a hydroelectric plan in converting the energy of the water into electricity is about 80 percent as compared with 33 to 42 percent for coal and 55+ percent for natural gas.[44]

While hydroelectric stations are not high in air emissions, they can have significant environmental effects related to the altered flow of bodies of water, water quality degradation, effects on fish and aquatic population, blockage of upstream fish migration, and flooding of land. In addition, the decay of organic matter in the shallow lakes created as a result of hydroelectric projects results in the production of small amounts of greenhouse gases.[45]

The capital costs for constructing a hydropower facility is estimated to be in the range of $1,700 to $2,300 per kilowatt hour (1996 dollars). These would necessarily be multiple small facilities based on availability of the resource. Operating costs of hydroelectric plants are generally fairly low, because the flowing river water generally has no direct cost associated with its use.[46]

Given that the significant hydroelectric resources of the state have already been captured and used for the generation of electricity for several decades, it does not appear that there is a potential for a significant amount of in-state hydropower to meet part of Minnesota's electricity needs. The major source of new hydroelectric power available to Minnesota would be from Manitoba Hydropower. The significant barrier to bringing more of this power down into Minnesota for use by retail consumers would be the construction of an additional transmission line to be able to have the capacity to move the power into Minnesota's electric grid and the environmental impacts.

WIND

Minnesota installed more wind capacity from 1995-2000 than any other state, over 380 megawatts. Minnesota ranked second in the nation in installed wind capacity at the beginning of 2001, but will be passed by several other states by the end of the year.

[44] Id. at 25.
[45] Greenhouse gas emissions from hydropower are many times smaller per kWh generated than from coal-fired generation.
[46] Id. at 26.

Wind energy is the fastest growing electric generation technology because the technology has developed to the point that it is cost-competitive with other technologies, the fuel is free, and environmental impacts are minimal.

Turbines being installed in 2001 are 1.5 MW each, with an efficiency of 40 percent in turning wind into electricity.[47] Wind turbines require a sufficient wind resource, and Minnesota is ranked third in the nation for wind potential.[48] North Dakota and South Dakota are ranked first and second for wind resource. They are a potential source for wind-generated electricity for Minnesota as well. Minnesota's wind potential is in the hundreds of thousands of megawatts of capacity. Only a small portion of that is physically and economically practical, but the number is in the thousands of megawatts.

The Department of Commerce has conducted a wind resource assessment program, monitoring wind resources in Minnesota to accurately measure and map wind speeds. Department data helps individuals, companies, utilities or independent power producers perform an initial assessment of the potential feasibility of a chosen wind site without the usual cost and delay of erecting a tower to measure the wind speeds for a long period of time. Figure 3-13 is the map of Minnesota's wind resource by wind speed class developed by Department researchers. Good wind resources are class 3 and above; Minnesota has several Class 4 and 5 wind areas.

The available wind resource is affected by a combination of elevation (higher is better), land use (less obstructed by trees and buildings for long distances is better), and geographic location. The southwestern corner of the state contains the best wind resource, mainly due to a geologic formation called the Buffalo Ridge which has elevated ground in a plains area of the state. There are other much smaller areas in the state that also contain class four and five wind resource, but much of the western and southern portions of the state is covered by what are considered "good" wind resources. Local site conditions will dictate specific wind resources.[49]

Figure 3-14 shows wind power development in Minnesota over the last 10 years, along with a list of planned installations. The biggest boost to the deployment of wind power was the Minnesota Legislature's mandate in 1994 that Xcel Energy deploy 425 MW of wind power by the end of 2002, of which 299 MW are currently operating. Xcel Energy has contracted for another 130 MW of wind power to complete this part of the mandate. The 1994 legislation also required the PUC to order Xcel Energy to acquire an additional 400 MW of wind power if the PUC found it to be cost-effective. The PUC has done so,

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[47] Docket No. CN-99-1815, Black Dog Repowering Project Environmental Analysis at 28 (2000).

[48] 1993 Pacific Northwest Laboratory study at http://www.nrel.gov/wind/potential.html.

[49] The wind resource is the fuel that produces the electricity to payback the cost of the turbine. Placing a turbine in a less resource rich wind site will not cost more, but the payback period for an investment will be longer.

and Xcel Energy must deploy 400 MW more wind power by 2012, a date that should be moved up to, at the latest, 2006.

Figure 3-14 includes some sites where wind power is used as a small, distributed generation source located close to local load, such as the Moorhead, Elk River and Averill locations. The market for locally-owned wind installations has not yet developed into a mature industry. Moorhead Public Service Utility, Lac Qui Parle School and two farmers in southwestern Minnesota are the exceptions. Municipalities, educational institutions, cooperatives, non-profits, local companies and individuals have a place in the development of locally sited, locally owned wind turbines. Several interested groups in Lake City and Northfield are working with the Department to monitor local wind resources in anticipation of installing a wind turbine, but the major impediment to further installations is a lack of financing. The installed costs, expected turbine output, and benefits stream can be determined with reasonable accuracy, but the perceived risk for a sizeable loan limits many projects without significant equity collateral. One of the advantages of the smaller facilities is that they may be interconnected at the distribution level, reducing need for and the cost of large transmission upgrades.

The cost of wind energy is strongly affected by average wind speed and the size of a wind farm. Small differences in average winds from site to site mean large differences in electricity production and, therefore, in cost. Larger wind farms often provide beneficial economies of scale. The cost of wind energy, however, is dropping fast, and is now competitive with or lower than the cost of conventional electric generation. Wind power today costs only about one-fifth as much as in the mid-1980s, and its cost is expected to decline by another 35-40 percent by 2006.[50] Figure 3-15 shows the dramatic drop in the cost of wind power since 1981. The U.S. Energy Information Administration studied the cost of wind, and concluded that the 2000 reference installed cost is $983/kW, and that that cost could drop under $800/kW by 2010.[51]

These study estimates are confirmed by the costs of actual projects. Figure 3-16 shows a series of 10 MW and greater wind projects deployed between 1996 and this year, with the most recent deployment dropping below $900/kW. Xcel Energy's deployments of wind power have been achieved at competitive cost levels of between 3 and 4 cents/kWh, with Xcel's standard small wind tariff set at $0.033/kWh. In Xcel Energy's most recent bidding process, Navitas Energy won an all-source bid for providing firm capacity and low-cost energy using a wind-gas hybrid consisting of a 250 MW natural

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50 American Wind Energy Association fact sheet, "Comparative Cost Of Wind And Other Energy Sources"

51 http://www.eia.doe.gov/oiaf/aeo/assumption/tbl77.html

gas turbine and a 50 MW wind farm. The all- source bid was open to all technology and fuel types.[52]

Wind generation has few adverse environmental effects. The primary concern has been the accidental deaths of migratory birds that get caught in the blades. The Department of Commerce, Environmental Quality Board (EQB) work with the Department of Natural Resources to analyze migratory paths of birds and avoid those locations in wind energy facility siting. Additionally, the increased height of turbines has allowed manufacturers to reduce blade speed. The same amount of electricity is still produced, but the turbine is less likely to hit birds than in the past. The EQB has closed its study on wind energy's effect on birds, due to lack of an effect in Minnesota. It is studying its effects on a species of bat.

Everyone knows that the wind does not blow at all times in all locations. In the best wind power locations, however, the wind blows well over 300 days per year. Electricity demand fluctuations, like wind fluctuations, are not abnormal and vary by thousands of MW in a single day and hundreds in a single hour, as was shown in Figure 1-10. Xcel, for example, normally dedicates an individual generating unit at one of its coal generating stations to "load follow" the fluctuations in the wind farm output. Each coal plant has several other units that are unaffected by this need. Xcel Energy requires a 3:1 ratio of wind capacity to firm back-up capacity.

Another way to manage wind's intermittency is to back it up with natural gas peaking capacity to handle hot summer days when the wind often does not blow. The Navitas Energy bid did this, and still won Xcel's latest all-source bid as the least cost option.

Utilities in the MAPP region carry a 15 percent operating reserve above demand levels to assure adequate system performance and to guard against sudden loss of power, for whatever reason, at generating stations in the system. For example, Prairie Island 1 went out of service unexpectedly for several weeks in August and September of 2001, including the week of peak electric use. Similarly, the King and Monticello plants were not operating at full capacity during the 2001 peak due to limits on the heat of the water they could release to the St. Croix and Mississippi Rivers. The reserve margin exists to cover this sort of contingency without the lights going out.

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[52] A recent analysis by Xcel Energy in its integrated resource plan "suggests that meeting 50 percent or 75 percent of incremental resource requirements by a combination of wind energy and conservation may be more economical than the base case [the proxy combustion units]...Wind plants may require more costlier transmission additions since the best wind resource appears to be in parts of the region with weaker transmission systems. Transmission costs are not reflected in [these] analyses...If wind is truly a better economic-environmental choice for customers, this outcome should be apparent in the more rigorous evaluation conducted in a [all-source] bidding process." Docket No. E002/RP-00-787, September 2000, p. 90-91.

The potential of wind energy in Minnesota is limited by the wind resources that are economical to develop and the percentage of the total grid-system that can accommodate a variable generating technology, like wind energy, without causing system instability. The exact point at which the integration of intermittent generation such as wind begins to degrade system economics is unclear, but the technical literature suggests that it is at penetration levels in excess of five percent.[53] Wind power is currently used to generate only 1 percent of Minnesota's electricity.

Other countries have learned to manage wind power as a much larger part of utility systems. In portions of Denmark, wind power accounts for 25 percent of the electricity on the electric grid at certain times of the year.[54] As a comparison, Denmark has 2,836 MW of wind capacity out of 12,000 MW total capacity (2000), in an area that is 16,629 square miles inhabited by 5.4 million people. Minnesota has 300 MW wind capacity out of 11,000 MW total capacity (2001) in an area that is 84,068 square miles inhabited by 4.9 million people.

A major issue in increasing use of wind power is transmission. The Buffalo Ridge wind resource area of Southwestern Minnesota is a part of the state that is relatively sparsely populated. Consequently there has historically been little need for load serving transmission infrastructure to be built in this area. The existing transmission system consists mostly of 115 kV level facilities and has been upgraded and utilized to the fullest extent possible to absorb the current increment of wind generation resources. If additional wind resources are to be developed in the area, then additional transmission infrastructure will be required to move the energy out of the area to distant load centers.

The development of another 400 MW in Buffalo Ridge would nearly double the total wind capacity in the area and would likewise require a doubling of existing transmission outlet infrastructure to deliver the energy to distant load centers. Transmission planners have been evaluating options for accommodating this projected increase in demand for transmission system use and have concluded that this now requires a larger transmission system. Even without additional wind development, this project is needed to provide additional electric reliability to the city of Sioux Falls and to strengthen the grid generally.

BIOENERGY

Bioenergy generally refers to the production of heat and/or electricity from renewable plant or animal resources. The Department is in the process of developing a database of

[53] http://www.igc.apc.org/awea/faq/putnam.html
[54] http://www.windpower.dk/faqs.htm#anchor58865

the potential bioenergy resources in Minnesota, similar to the wind and solar resource assessments the Department has done.

Anaerobic Digesters – Biogas

Anaerobic digestion is not a particularly new process or technology for producing electricity, but lately, its value in reducing, mitigating, and/or disposing of certain waste-streams has been recognized. Methane gas is produced when organic matter is broken down by bacteria in the absence of air. This can occur and be utilized in landfills, manure facilities, waste-water treatment plants, and other industrial waste streams. Utilizing these gaseous resources involves containing and enhancing the gas production so it can be economically captured and converted to electricity and/or useable heat. Several of each of these resource facilities exist in the state, but one location of particular interest is at farms and facilities that house animals and their subsequent waste.

Animal manure has been traditionally collected and stored for later application to farm fields. The storage facilities are generally large lagoons that can pose air and water risks to the surrounding community. An anaerobic digester acts as a manure processing facility that treats the waste before it is sent to the holding lagoon. Processing the manure removes many of the compounds that cause the acrid odor, reduces pathogens, produces methane gas, and creates what is ultimately a better product – composted organic matter. Anaerobic digestion is not a silver bullet, but it can be part of the answer to many livestock issues.

Manure digesters can address energy, environmental, social, and agricultural issues – although capturing all of these potential benefits in monetary form is difficult. The most direct monetary gain comes from selling back electricity to the local utility and using the waste heat instead of purchasing and burning propane for heating buildings and water. It is difficult to place a value on the reduced risk of a raw manure spill, the decreased odor in neighboring areas, the better quality fertilizer resource, or the input of capital development and income in rural communities with complete accuracy. These monetary values will vary by installation. The electricity produced, however, is really secondary to the benefits of better manure management.

The digester itself consists of a large, generally concrete, pit that contains the manure and a flexible/inflatable cover to contain the methane gas. An engine-generator burns the methane to produce electricity, although a microturbine or fuel cell could ultimately work as well. Piping, wiring, pumps, generator housing, and other associated components are needed as well. The digesters have an operating life of 15-20 years, with a major clean-out of sand and debris from the digester required approximately every five years.

Methane digesters have a high capital cost, mostly consisting of the concrete and excavation of the digester itself and the engine generator. The operating digester in Princeton (MN) cost approximately $355,000 to build and was funded with a combination of grants, loans, and private funds.[55] It was built to contain the manure from 1,000 dairy cows and currently has a 125 kW generator, which is undersized for the amount of methane gas that is being produced. There are plans to add an additional generator at this site in the future. The Department plans to fund a digester installation at a swine facility to monitor its costs and benefits as well.

Estimating the costs of future facilities is difficult and contingent on a variety of factors. The payback is dependent on the buyback rate for the electricity and the utilization of the waste heat in place of propane gas for heating buildings and water. Without additional funds and using conventional loan sources, payback periods are between ten and fifteen years, which is generally above the threshold for private investment. The 2001 Legislature authorized an incentive payment of $0.015/kWh to new qualifying digester systems, which mirrors the payment for certain small hydropower and wind facilities and could push borderline projects into the realm of profitability.

The largest single barrier to further installation of manure digesters is access to financing. As with wind turbines, the perceived risk limits the access to financing, especially with existing outstanding loans for many farmers. Additionally, many of the secondary benefits such as odor abatement and less hazardous organic waste are not given monetary value in the traditional sense. One option may be to require facilities sited in certain areas to use digesters, such as near water sources or homes. Another option might be to require installation of anaerobic digester technology at a particular site in response to environmental problems or violations at the facility. These options are not really related to energy issues and would be best deliberated by agricultural and environmental agencies.

Forest and Agricultural Products – Biomass

Biomass energy installations generally combust forest and/or agricultural products in a similar manner to coal power plants. Biomass can be classified into two categories – closed-loop and open-loop. Closed-loop systems use a product that is grown or developed specifically for producing energy, such as alfalfa, switch grass or cultivated poplar, aspen or willow. Open-loop biomass systems use a product that is a by-product or waste of another activity. Examples of fuel sources include waste wood from logging or paper processing, urban wood collected after storm damage, sawdust that is made into pellets, or poultry litter.

[55] Nelson & Lamb, Final Report: Haubenschild Farms Anaerobic Digester, The Minnesota Project, December 2000.

Biomass facilities convert fuel to electricity with an efficiency of 15 to 30 percent, depending on fuel quality. Dry, low-ash biomass fuels could yield higher efficiencies than wet, high ash feedstocks. National studies indicate that these facilities cost about $1,476 per kW (1996 dollars).[56]

Biomass fuels can also be "co-fired" with other traditional fossil fuels at boilers that are capable of handling this fuel. The fuel mix (wood and coal) can be adjusted according to the cost and supplies of the available fuels. In order to successfully co-fire wood with coal, the power plant's fuel feed system and boiler must be capable of handling wood. Future combustion capacity will need to consider the fuel handling needs: pulverized coal-fired boilers cannot routinely accept wood; cyclone boilers can (and have) burned wood chips and sawdust; nearly all spreader-stokers are already burning wood fuels. Minnesota Power's proposed Rapids Power Project is a circulating fluidized bed that will be able to burn both fuels.

The capital cost of a new biomass-fired facility may be competitive with similar-sized coal-fired boiler – depending on the amount of fuel preparation needed. For example, open-loop facilities contracting to burn prepared waste wood like urban waste wood may not need to install equipment that shreds and sizes wood to easily feed into a boiler. These facilities instead need to devote resources to address planning, coordination and transportation to ensure that they secure fuel at reasonable prices. If they are not successful, then the facilities will need to install some sort of processing equipment to be able to accept a wider variety of wood types.[57]

Closed-loop systems are viewed as having a greater potential to provide greater reliability in the long-term over open-loop systems; however, their fuel costs are higher than open-loop systems because they must include the cost of raising and harvesting the fuel.

It will take some work to develop dedicated crops. Hybrid trees could potentially be grown on marginal quality or Conservation Reserve Program (CRP) land, providing additional income to agricultural areas, if farmers/landowners make these lands available. It takes up to 10 years for trees to mature enough to harvest. During this period, farmers must bear the production costs without income from this crop. In addition, landowners are concerned that should the market not appear during this

[56] Docket No. CN-99-1815, Black Dog Repowering Project Environmental Analysis, at 35 and 37 (2000).
[57] In addition, waste wood users are faced with the task of keeping treated wood out of the facility. Pentachloraphenol (PCP)-treated wood contribute to the production of dioxins in the flue gases, which may require further air pollution control equipment. Chrominated copper arsinate (CCA)-ash is highly toxic (much more than the wood itself). Both of these wastes could require the use of more sophisticated air pollution control equipment to avoid unacceptable releases to the air, and could result in ash that requires special handling and disposal.

period, they face significant landclearing costs to return to more traditional agricultural crops. These are barriers that would need to be addressed.

Open-loop systems compete with other systems already in place in Minnesota. For example, the wood products industry has been efficient at converting its waste wood into usable energy for its own production, and little appears to be widely available for large power plants. Therefore, an important aspect of developing future wood waste fired projects is to investigate the amount of wood available. Poultry litter facilities are competing with litter's existing use as fertilizer.

Each of the bioenergy fuels described here (biogas from animal wastes, wood and briefly, poultry litter) all have attractive environmental benefits to their expanded use. Most obviously, they represent no net gain in carbon dioxide emissions to the atmosphere when combusted to product electricity. Because they are low in fuel sulfur, they represent lower SO_2 emissions, especially if used to displace fuels currently in use, like wood for coal. They have fewer toxic constituents, and so do not contribute substantially to the release of persistent bioaccumulative toxics.

Figure 3-17 compares the emissions of wood, poultry litter and animal waste to that from pulverized coal (as represented by emissions from the Taconite Harbor coal power plant at Schroeder, Minnesota). Of most interest are the emissions of NO_x from biomass fuel-fired facilities. Due to the high amounts of nitrogen in biofuels, NO_x emissions are higher than traditional fossil fuels, even when best available control technologies like selective noncatalytic reduction is used. the concern related to NO_x emissions is not inconsequential; the Twin Cities exceeded ozone standards for the first time in nearly 20 years this past summer. Ozone exceedances are related to NO_x and VOC emissions. Replacing traditional fossil fuels with biofuels will not alleviate ozone concerns; in fact, use of these fuels in projects will require close attention to prevent aggravating ozone issues.

SOLAR

Solar powered electricity can be made using a variety of technologies, but for practical purposes is limited to what are called photovoltaics, which are flat solar panels made of silicon cells that transform sunlight into electricity. The panels themselves perform reliably, with warranties of 20 years or more. The secondary equipment that distributes and transforms the electricity into a grid-compatible form tends to be the technological weak link. Solar electricity has remained outside of the mainstream largely because of costs and efficiencies. Traditional paybacks on solar installations remain high and the large market is in off-grid and niche applications such as solar-powered outdoor decorative lighting.

Many Minnesota cabins are powered by solar electricity, as well as a scattering of small buildings at state parks and other facilities. The majority of the large orange flashing construction signs are solar powered, as well as many emergency call boxes on the state's highways. There are less than 100 kW of grid-connected photovoltaics installed in Minnesota, with the largest installations being at the old Science Museum (St. Paul), Battle Creek Elementary School (St. Paul), the Burnsville Transit Station, and in Winnebago, Minnesota. Xcel Energy manages 17 photovoltaic installations around the Twin Cities of about 2 kW each as part of its Solar Advantage Program which began in 1996.

The Department has recently completed a resource map outlining the solar resources in the state, shown in Figure 3-18. The southwestern portion has the highest areas of solar resource, with the northeastern portions being the lowest. These extremes differ by only about 10-15 percent and unlike wind power, represent a direct proportional relationship between insolation and power generation. Insolation, as opposed to radiation, is that portion of the sun's rays that reach the earth at sufficient strength to create usable energy.

Surprisingly, Minneapolis has a greater summer solar resource than Jacksonville (FL), as shown in Figure 3-19. Minneapolis, however, has a very low winter solar resource, which makes Minneapolis and Jacksonville nearly equal in terms of estimated annual electricity production.

Initial data from Xcel Energy's Solar Advantage Program indicate lower electricity production amounts than those estimated in Figure 3-19, ranging from 1,174 to 1,334 kilowatt hours per kilowatt of installed capacity per year. Tree shading, snow cover, and low tilt-angle were all factors in the decreased "real-world" generation data.

Xcel Energy estimated an installed cost of $8,500/kW in 1996, which was much less than comparable installations at the time[58]. This equates to a cost of about $0.30/kWh over 20 years. Current installed costs are estimated at $6,000-7,000/kW. Despite these costs, there is a high demand for solar electric systems, especially in California, where electricity problems and state incentive programs are widely available.

Solar electricity, like wind energy, is an intermittent technology. However, solar electricity has a positive correlation with electricity demand, meaning that solar panels statistically produce electricity when it is needed most – hot, summer days. Department of Commerce staff analyzed three of the Xcel Energy Solar Advantage installations. During periods of highest electricity demand the installations exhibited from 26-68 percent capacity. Tracking mechanisms, which let the panels actively follow

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[58] http://www.upvg.org

the sun across the sky during the day, can increase this capacity performance even further.

The wide-spread commercialization of photovoltaics is largely dependent on manufacturing cost reductions, research and development gains, and / or incentives for installation. Photovoltaics' installed capacity in Minnesota will likely remain limited in the near-term.

One area of potential, other than those already mentioned, is in urban locations with electric demands that are taxing the transmission and distribution system. An example might be in south Minneapolis where electric demand is increasing from the retrofitting of homes with new central air conditioners. Transmission and / or distribution system upgrades may be necessary in the future unless demand is decreased or unless additional generation can be locally sited. Photovoltaics, with their silent operation, low-profile, and no pollution might be an alternative to these grid upgrades.

Photovoltaic cells used to produce electricity from the sun's energy produce no emissions to the air or water in operation. Access to solar energy may require the removal of some trees in certain operations.

DISTRIBUTED GENERATION

Distributed generation is not one technology but a group of technologies that lend themselves to specialized applications.

Distributed generation is local, small-scale power generation, and although it is receiving heightened attention, is not a new concept. Starting with Thomas Edison's first plant in the Wall Street district of New York City, early electrical generation was predominately small scale. Such a system was popular with factories, who could put to use the waste heat generated by power plants and save money. As utility systems developed, however, they looked to the economies of scale that could be realized with larger power production facilities. As the price of centrally produced power fell, it was more economical for businesses and factories to purchase power from a centralized source. The only industries that still continued to produce their own power were those industries that had byproducts that could be used to fuel a boiler, i.e. the forest products and petroleum industries.

Distributed generation resources often offer better efficiencies than central station power generation and transmission, because the electricity is generated close to the end user. This avoids the line losses that occur in the typical transmission and distribution system. Another efficiency that distributed generation can offer over central station generated electricity is the ability to capture the heat from the electrical generation process and use it to heat or cool a conditioned area, or offset the costs of a particular manufacturing process.

Distributed generation can employ wind turbines, small hydroelectric plants, microturbines, photovoltaics, fuel cells or diesel generators – essentially any generation source of 10 megawatts or less. The environmental impacts depend on the generation source and are shown in Figure 3-20. Some of the technologies listed in Figure 3-20 are not yet economically feasible, e.g. fuel cells.

DIESEL

Of the types of generation mentioned above, diesel generators are the most polluting per kilowatt-hour generated. They emit many air pollutants at high levels. In recent years, a substantial quantity of distributed generation capacity has been installed in the state of Minnesota. Informal surveys suggest that, in aggregate, 300 MW of installed distributed generation capacity currently may be in place in the metropolitan Twin Cities area. Modular diesel capacity is the most popular form of distributed generation. Most diesel generators are small, 1 MW or less in generating capacity.

Aggregate annual emissions from modular diesel generation are probably small in relation to statewide emission totals. However, due to their short stacks, and their location where people work and live, the operation of modular diesel generators can significantly degrade local air quality conditions in the immediate area, including violation of ambient air quality standards. Pollutants emitted from diesel combustion include NO_x, CO, CO_2 and SO_2. Further, particulate matter from diesel engines is an important concern. See Appendix A for a detailed discussion of these pollutants and their effects on humans and the environment.

A potential partial mitigation of the emissions from diesel generators is biodiesel fuel. Biodiesel fuel is commonly made from a chemical reaction between soybean oil, methanol, and lye, although other non-petroleum oils and greases can be used. Biodiesel can be used in its pure form or can be blended to any percentage. A common blend is a ratio of 20 percent biodiesel mixed with 80 percent petroleum diesel, also known as B20.

Biodiesel's use as a transportation fuel in diesel engines is becoming well known, as evidenced by the legislative debate in the 2001 Session regarding biodiesel. Biodiesel can also be readily used in standby, emergency, and remote diesel electric-generators used by electric utilities and other power producers. The State Energy Office in the Department of Commerce funded a demonstration of the use of biodiesel in over 15 diesel generators which provided the electricity for the Taste of Minnesota in St. Paul in 2000. The fuel worked well.

Many new diesel generator installations fall under the threshold for environmental or energy regulations which makes them an attractive choice for peak power needs. While the actual run-times for these diesel generators is generally low on an annual basis, their combined use on hot days can produce significant amounts of pollution. Biodiesel can reduce sulfur, carbon monoxide, volatile organic compound, and particulate matter emissions in proportion to the amount of diesel fuel it replaces. Biodiesel does not reduce nitrogen oxide emissions.

The cost of biodiesel has dropped significantly in the last year from roughly $3.00/gal to $1.50/gal, largely due to a federal program to encourage biodiesel production. Biodiesel in a B20 mix costs $1.10/gallon and $1.50/gallon if 100 percent biodiesel (B100) is used.

A typical 2 MW stand-by diesel generator may only operate 200 hours each year and consume roughly 25,000 gallons of fuel. If the cost of diesel fuel is higher than $1.00/gal, which has been the case for the last year, the incremental cost gap shrinks accordingly. The barriers to the widespread adoption of biodiesel are primarily cost and lack of a developed distribution system. Also, utilities and consumers lack motivation to use biodiesel since no direct requirements or incentives exist to promote it or to discourage petroleum diesel.

While numerous studies have been conducted on emissions from transportation engines burning biodiesel, relatively few tests have been done on emissions of diesel generators burning biodiesel. In general, however, results are similar to those of the transportation engines burning biodiesel.[59] Carbon monoxide, hydrocarbon and particulate emissions are reduced and nitrogen oxides emissions increase slightly compared to conventional diesel fuel. Sulfur dioxide emissions are a function of the fuel sulfur content and will decrease proportionately as the amount of diesel fuel is decreased in the blend because the sulfur is in the petroleum diesel fuel.

Distributed Generation Using Combined Heat and Power

Generating electricity through the combustion of fossil fuels inevitably produces heat. Combined heat and power (CHP) is the process of utilizing the heat generated as a result of electricity production. Centralized power plants operate at electrical conversion efficiencies of roughly 30 to 35 percent. This means that roughly nearly 70 percent of the energy content of coal is released into the atmosphere as waste heat. One of the distinct advantages of distributed generation is that electric generation is located nearer the end-user, thus the heat generated from the production of electricity is readily available for utilization. When the heat associated with the electric generation is fully

[59] Conversation on October 1, 2001 with Shaine Tyson, Renewable Diesel Project Manager, National Renewable Energy Laboratory, Golden, Colorado.

utilized the efficiency of the entire system can approach 80 percent. Such a process has inherent cost savings because the natural gas or electricity that would otherwise have been used to heat or cool an area is no longer needed.[60]

Boilers and steam turbines are the most common method of CHP, as well as the method that has been around for the longest time. This system can burn the widest range of fuels, and has been popular with those industries that can use the byproducts of their production processes, notably the forest products and petroleum industries.

Microturbines are based on the concept of many jet engines. Microturbines are able to generate electricity efficiently with low emissions, and high value heat. The heat can be used to heat or cool a conditioned area, dehumidify a conditioned area, or offset some of the energy costs within a particular manufacturing process. Microturbines are currently commercially available, with costs of about $1000/kW.

St. Paul has one of the world's premier CHP projects. The St. Paul District Heating and Cooling Plant has provided both heating and cooling services for the buildings that operate in the downtown area of St. Paul. Construction is now underway to incorporate an electrical generation system that will utilize the waste wood products within the metro area. Once completed, this facility will provide power, cooling, and heat for the 141 buildings that are connected to the system in downtown St. Paul. The efficiency of the new CHP plant in downtown St. Paul is expected to approach 75 percent. With the planned biomass CHP project, estimated air emission reductions include 280,000 tons of CO_2 and 600 tons of SO_2. Other district heating systems that have cogeneration facilities include the public utilities in Willmar, Hibbing, Virginia and New Ulm, the University of Minnesota in Minneapolis, and the Franklin Heating Station in Rochester. This project, at 25 MW capacity, is larger than what usually would be considered distributed generation, but other smaller distributed generation technologies are excellent CHP produces as well.

A recent study inventoried Minnesota’s cogeneration (CHP) potential and did case studies on three high potential cogeneration sites: Rahr Malting in Shakopee (9.3 to 10.4 MW), Chippewa Valley Ethanol in Benson (3.4 to 7.4 MW) and Duluth Steam Cooperative (0.9 MW).[61] The study surveyed 142 facilities that had potential for large (over 1 MW) cogeneration projects and received 32 responses. Analysis of the survey responses indicated that four sites had high CHP potential and ten sites had some CHP

[60] The U.S. Combined Heat and Power Association was formed in early 1998. They have developed the goal of doubling the CHP installations (from 1998 levels) in the U.S. from 46 GW to 92 GW by 2010. Much of the additional capacity will come in the industrial sector, where there is an estimated potential of 88 GW of CHP. Some of the target industrial markets that they have identified are pulp and paper, chemicals, food processing, metals, and machinery.
[61] Inventory of Cogeneration Potential in Minnesota, Minnesota Planning (2001).

potential.[62] The specific case studies found potential for economic deployment of CHP at the three facilities analyzed. The main variables affecting economics are the price of the fuel (natural gas, biomass or coal) that would be used in each CHP project and the ability to sell excess power into the grid at the market price of electricity.[63]

<u>How can heat be used to cool a building?</u>

Cooling with heat provides a year round application for the heat produced by certain distributed generation resources.

Absorption cooling is different from traditional mechanical cooling in that liquids are the medium used for refrigeration, rather than vapors. This means that less work is required to operate a absorption refrigeration system than a mechanical refrigeration system. However, an absorption refrigeration system requires that the working fluid, which is generally a mixture of ammonia and water, be separated. This separation is accomplished through the use of heat. When a low cost source of heat is available the economics of an absorption refrigeration system are greatly improved. Thus, combined heat and power systems can provide electrical generation and space conditioning on a year round basis. There are two types of absorption refrigeration systems currently available, double effect and single effect. Single effect absorption systems typically have a coefficient of performance (COP) of 0.65. Double effect systems are somewhat more efficient than their single effect counterparts, and have COPs in the range of 1.2, meaning that for every unit of work that goes into the system, there are 1.2 units of cooling.

Desiccant (Dehumidification) wheels remove the moisture from the air, making it more comfortable at higher temperatures, as well as easier to cool. A desiccant wheel can provide major benefits in Minnesota because of the humid conditions we experience in the summer. A desiccant wheel consists of a wheel of packed material capable of removing moisture from the exterior environment. As the wheel removes moisture heat is required to remove the moisture from the desiccant wheel. There are many applications where the removal of moisture is advantageous to the space conditioning of a facility. Basically, dry air is much easier to cool than humid air. Indoor ice rinks are an example of a niche market for desiccant wheels. Within the context of a CHP system, the heat generated by the system can, in turn, be used to recharge the desiccant wheel.

[62] Projects classified as good, some potential, and poor are listed in the study. <u>Id.</u> at 16.
[63] <u>Id.</u> at 18-34. Not allowing for economics, potential CHP deployment in Minnesota is over 1600 MW at large facilities (over 1 MW) and over 800 MW at small facilities (under 1 MW). Id. at vi.

Desiccant wheels have a niche market in supermarkets and grocery stores, where high humidities contribute more to the cooling load. Supermarkets can take advantage of the waste heat from a microturbine or other distributed energy resource to recharge a desiccant wheel application. This would help the supermarket deal with the high humidities, as well as generate electricity to offset their utility consumption.

In both applications low cost, high quality heat is necessary for the process to be economical.

Power Quality and Reliability

Electric outages can have significant financial impacts. The losses are not limited solely to the lost business that a power outage brings with it, but also equipment downtimes, startup, and lost production. To address this concern, some businesses to make large capital investments in distributed generation technologies such as fuel cells and microturbines. In addition to increased reliability, these technologies also offer higher quality power than that provided by the grid.

Some businesses that have "mission critical" operations require an extremely high level of power reliability. "Six nines" of reliability are quickly becoming the requirement for many businesses that operate in today's e-commerce market. Six nines of reliability means that power must be available 99.9999 percent of the time, this is equivalent to a power outage of 32 seconds per year. Utility power averages 99.9 percent reliability or less, which is the equivalent of over eight hours of power outages. These stringent requirements for power reliability have become a necessity for businesses that lose extraordinary amounts of money during a power outage.

A recent report by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, entitled *Strategic Plan For Distributed Energy Resources* offered the estimates of the cost of power outages for different business segments shown in Figure 3-21.

Interconnection of Distributed Generation to the Grid

Work is being conducted at state and national levels to develop a standard for interconnecting distributed generation technologies to the utility grid. For many years utilities have cited line worker safety as the main reason for opposing particular distributed generation projects. The Institute of Electrical and Electronic Engineers (IEEE) P1547 working group is developing a voluntary standard for the interconnection of distributed generation equipment, including CHP, to electric power systems. There are more than 300 participants in the working group, and the standard is expected to be published by the end of 2001.

The Legislature has required that the PUC adopt standards for interconnection of distributed generation that uses natural gas or an equally clean or cleaner fuel under 10 MW in Minnesota that should remove some barriers to deployment of these technologies. These procedures have already been studied and adopted in other states. The method developed in Texas delineates the requirements for each party in a clear manner and should be adopted in Minnesota.

For facilities that are 40 kW or larger and do not quality for net metering, interconnecting with their local utility requires a process that balances the costs, timeframe, and intricacies of developing an equitable, legal agreement between the two entities, while maintaining safety and quality standards.[64] The ability of distributed generation technologies to "plug and play" will encourage deployment.

Research is underway by the University of Minnesota, Electrical Engineering Department to assess the amount of distributed resources that the electric grid can feasibly handle.

Net Metering

The statutory threshold for net metering needs to be increased. Net metering is an energy policy which lets distributed generators receive a credit for electricity generated on site equal to the price they pay for electricity. In its purest form, net metering simply lets a distributed generator's electric meter spin forward and backward, depending on whether the on-site generation meets all on-site needs or whether further electricity is drawn from or contributed to the grid. At the end of the month (or other time period), the balance is trued up and a check is paid by the utility or the consumer, depending on whether more electricity was consumed or generated. Currently, about 30 states have some form of net metering.

Minnesota was one of the first states to enact net metering and has had its policy since the early 1980s. Net metering is available to renewable, waste, and cogeneration energy facilities of less than 40 kW, which is a relatively small size. For example, it is smaller than the common size of today's wind turbines, often 250 kW, 750 kW, or larger. Net metering policy has not been revisited in quite some time.

Technological advances have been achieved that can simplify the net metering process, reduce costs to both the utility and the net metering facility, and maintain safety. One example is the requirement for installing two electric meters. For a solar-electric system

[64] A proposed wind turbine installation that is 40 kW or larger often necessitates hiring a lawyer and an engineer to understand and negotiate a complicated interconnection agreement with the utility, making deployment especially difficult for small cities, institutions, small businesses and farmers.

(2 kW), the metering charge from the utility can be greater than the value of the electricity produced during winter months and a significant percentage in the summer months. For a small wind system (20 kW), this metering charge is only a fraction of the monthly energy charge. Making the second meter optional for the consumer/generator would, in cases where the single meter is sufficient, reduce costs. Letting consumers decide whether to install the second meter, when knowing the exact amount of electricity generated is important, might be an important option to consider.

For larger distributed generation installations (over 40 kW or so), the consumer/generator would not need the utility to pay its retail rate for extra electricity and ratepayers should not pay that much either. Net metering ought to be available for clean distributed generation facilities up through 2 MW in size, but the price the utility must pay for power sent into the system should be either the regular wholesale price or something between the wholesale price and the retail price. The prices should be generically determined, based on the technology used, by the MPUC.

ENERGY FROM SOLID WASTE MANAGEMENT

Electric energy can be generated as a byproduct of solid waste management in two different ways.

First, landfill gas (LFG) can be collected and burned to produce some electricity. Second, mixed municipal solid waste can be processed into refuse-derived fuel and burned in generators to produce some electricity, or can be massed burned without processing to produce some electricity. Both methods of generating electricity have been used by the state as part of the state's comprehensive approach to solid waste management.[65]

Mixed Municipal Solid Waste

In the Waste Management Act, Minnesota Statutes Chapter 115A, the state began a series of initiatives in the 1980s to reduce the amount of solid waste deposited in landfills in Minnesota. In addition to a dramatic increase in recycling efforts, many counties chose to either build or send solid waste to facilities that could burn the waste and reduce its volume and generate some electricity to help offset the cost of the project. The building of incinerators or conversion of power plants to burn solid waste was implemented aggressively in the 1980s, and was very controversial due to concerns about air emissions from burning the wide variety of materials present in solid waste. The state has now developed, and has had in place for some time, a comprehensive

[65] The state has burned mixed municipal solid waste for the past 15 years, and landfill gas for the past seven years.

environmental regulatory program with waste combustor rules that apply to this type of facility.

Minnesota currently burns about one quarter of its municipal solid waste in municipal waste combustors. Five of the state's ten municipal waste combustors generate electricity, the others produce steam for sale to co-located manufacturing facilities. Figure 3-22 shows the five waste combustors that burn either refuse-derived fuel or unprocessed solid waste and generate electricity for sale to the local utility.[66] This table shows that, at present, waste combustors in the state generate a combined total of 128 megawatts of electric capacity.

No new municipal solid waste combustor has been built in the state since a court decision that struck down counties' ability to require that waste be sent to these facilities. As a result, if it is cheaper to transport the solid waste to a landfill, waste haulers have chosen to do so. This has largely resulted in Minnesota's solid waste being trucked out of state for disposal in landfills. It is unclear, given that the waste cannot be required to be burned in these facilities, whether there is further room for economic development of any more facilities.

More importantly, the main function of these facilities was to implement county solid waste management plans and reduce the amount of solid waste directly landfilled. While these facilities generate some electricity that helps defray the cost of the solid waste management function, they would not, standing alone, have been likely to be economic electric generation plants.

The primary air pollutants related to municipal solid waste combustion are polychlorinated dioxins and furans ("dioxins") and mercury. Dioxin is produced when waste containing chlorine compounds is burned. The amounts of dioxin formed during waste combustion is variable and dependent the composition of the waste, the temperatures at which it is burned, and the type and operation of air pollution control devices. Mercury releases depend on the amount of mercury in the waste and subsequent air pollution control devices.

Dioxin is an endocrine disrupter, and may impair immune systems as well as increase the risk for cancer. Because it is persistent and accumulates in biological tissues, the major route of human exposure is through beef and breast milk. Municipal waste combustor emissions of dioxin account for only a small fraction of the dioxin emitted in Minnesota. On-site disposal of waste through burning (burn barrels, fire pits, etc.) is estimated to be a much larger source of dioxins. In Minnesota, the Office of Environmental Assistance estimates that the amount of dioxin emitted from burn

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[66] Incinerators operated by the City of Fergus Falls, Polk County, Pope-Douglas Counties, the City of Perham and the City of Red Wing process solid waste, but do not generate electricity.

barrels is the equivalent of 80,000 to 160,000 full scale municipal waste combustors, whose emissions are controlled.

Because of the use of mercury in consumer products like batteries, fluorescent lightbulbs, pigments and biocides, burning municipal solid waste releases mercury. Municipal solid waste contains four times more mercury than coal on a Btu basis. Air pollution control has significantly reduced mercury emissions, but waste combustors still release two times more mercury to the air than coal per kilowatt-hour generated.

Landfill Gas

Significant quantities of methane gas and other volatile organic compounds are emitted from municipal solid waste deposited in landfills. This gas can be used for generating electricity on the site of the landfill. An electric generating plant using Landfill Gas (LFG) is similar to one using natural gas, except it needs more extensive gas processing and more careful monitoring of equipment because of the potentially corrosive nature of LFG. An LFG system consists of a gas collection system which gathers the LFG being produced within the landfill, a gas processing system which cleans the gas and converts it into electricity, and interconnection equipment to deliver the electricity to the power grid. Figure 3-23 shows four projects in the state where LFG is used to generate electricity.

Many of the LFG gas projects that can generate significant amounts of electricity have already been constructed. A 1996 study by the United States Environmental Protection Agency concluded that landfill gas based electric generation potential in Minnesota is about 14.3 megawatts. Another study, developed in conjunction with the certificate of need for the Lakefield Junction natural gas plant, estimated that LFG based electric generation in Minnesota could add approximately two megawatts per year in additional generating capacity if all landfill gas opportunities could be developed.[67]

These systems convert energy at an efficiency of approximately 25 to 35 percent. This figure includes allowance that approximately 70 to 80 percent of the gas generated in a landfill is capable of collection, as well as the typical efficiency of generators being between 35 and 45 percent. LFG systems are very reliable, and would be expected to be available for combustion more than 90 percent of the time.[68] The air emissions from a landfill gas project would yield a net reduction in the greenhouse gasses emitted from landfills due to the combustion of methane. Operation of the combustion system would produce some additional emissions of nitrogen oxides, and lesser amounts of other air pollutants. Generally speaking, however, the overall emissions from this type of project

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[67] Docket No. CN-99-1815, Black Dog Repowering Project Environmental Analysis at 37 (2000).
[68] Id. at 38.

would be expected to provide a net benefit to the atmosphere due to the combustion of greenhouse gases.

The capital costs for constructing a landfill gas facility is expected to be less than $1,000 per kilowatt. Annual operating expenses might be less than for a typical fuel-fired power plant because the landfill gas is not typically a purchased input. If a landfill gas system is capable of producing electricity in some amount, the income to the combustion system operator would offset part of the overall cost of abating landfill gas.[69]

Where economical to invest in the equipment that could burn LFG to generate electricity, this has largely been done in the state of Minnesota. MP-Allete investigated the prospects for further LFG combustion to generate electricity a couple of years ago and found that the cost-effective sites had already been developed. Like the combustion of solid waste, the combustion of LFG to generate electricity serves more to improve the economics of the solid waste management system, rather than contribute a significant amount of capacity to the electric grid. In that sense, the fact that these projects can generate electricity can be very helpful to the state in reaching its solid waste management and air emission goals. It is not expected, however, that sufficient capacity exists from either approach to significantly impact the expected capacity deficit in the state over the next few years.

FUTURE TECHNOLOGIES

Fuel Cells

The modern version of fuel cell technology was originally developed as part of the Apollo moon program. A fuel cell is an electrochemical device that operates much like a battery. As long as hydrogen and oxygen fuel flow into it, direct current electricity and hot water will flow out of it. Since it operates on a chemical combination of hydrogen and oxygen to produce water and heat it has no combustion process and no air emissions. Because of the modular characteristics of the technology, installations can be sized from small kW scale applications to multi MW installations.

Developing a sufficient hydrogen source to operate many fuels cells is one of the complex set of requirements for broad utilization of this technology. Hydrogen can be produced from water by electrolysis, the source of the electricity for this could be renewable or conventional sources, but the most common source of hydrogen today is through refining of crude oil, or from methanol, ethanol, natural gas (methane), and even gasoline or diesel fuel. Using these traditional fuels that contain hydrogen as an energy source for fuel cells requires a pretreatment of the fuel, in a "fuel reformer" that

[69] Id. at 39.

extracts the hydrogen for use in the fuel cell. Wind turbines can efficiently produce hydrogen from water.

Most fuel cell technologies are at the beginning of their commercial deployment. There are many types of fuel cell technology under development, Phosphoric Acid, Proton Exchange Membrane (PEM), Molten Carbonate, Solid Oxide, Alkaline, Direct Methanol, and Regenerative fuel cells. Each version of the technology type is at its own stage of development and commercialization. Phosphoric Acid cells were the first to be commercially deployed. A 250 kW version has been marketed for years. There are now over 200 of these fuel cells installed.

Demonstration systems based on each of the other approaches are in operation. A major commercialization effort has been initiated by companies at the 5 kW size range for residential applications for electricity and hot water use. A much larger 5 MW demonstration system is now operational powering a post office complex in Alaska.

There are a variety of size options for this technology. Fuel cells can be created in sizes so small that they are being considered as power sources for portable phones. PEM fuel cells are attracting attention in the transportation market due to their light weight. Significant R&D activity is underway in the automotive industry to optimize these size and weight attributes.

The integration issues for fuel supply and heat and water outputs, along with low manufacturing volumes, have tended to make fuel cells expensive compared to more established gas turbine or gas engine products. Over time, with product evolution and increased sales volumes, fuel cells may be a more competitive power generation source.

These solid-state devices can operate at relatively high fuel-to-electricity conversion efficiencies (47-65 percent). This efficiency advantage coupled with the potential for use of the thermal hot water output makes this a likely competitive technology to the more conventional turbine or engine based technologies. Figure 3-24 shows the current and forecasted cost of fuel cell generation, and also shows how costs are expected to decrease as mass production increases.

Fuel cell technology is undergoing rapid change. Many entities are developing commercial products and much research is underway to improve the current state of technology. Many companies are expecting to enter the commercial marketplace with a product in the next three years.

Hydrogen

Hydrogen is the third most abundant element on the earth's surface, where it is found primarily in water (H2O) and organic compounds. Hydrogen is produced generally from the electrolysis of water or the reformation of such fuels as natural gas, coal, gasoline, or methanol to extract the hydrogen component. When hydrogen is burned or when it is converted to electricity directly using a fuel cell it joins with oxygen to form water. A hydrogen-based economy would need a future hydrogen infrastructure that would make hydrogen widely available to the consumer market much like petroleum infrastructure. This infrastructure would allow the use of hydrogen for a variety of uses in fuel cells such as producing heat and electricity in homes and businesses or as a transportation fuel.

There are a variety of sources of hydrogen and technologies used in its production. The four main technologies used to produce hydrogen are thermochemical, electrochemical, photoelectrochemical and photobiological. Thermochemical technologies are being used to produce hydrogen by reforming fuels such as natural gas, coal, methanol, gasoline, or other biomass fuels. Electrochemical technologies use the process of electrolysis to produce hydrogen by passing an electrical current through water. Photoelectrochemical technologies produce hydrogen by illuminating a water immersed semiconductor with sun light. Photobiological technologies produce hydrogen using the natural photosynthetic activity of bacteria and green algae. Currently the most economic source of hydrogen, widely available today, is from the reformation of natural gas to remove and clean the trapped hydrogen.

The future use of hydrogen as a fuel will largely depend on development of a safe and cost-effective infrastructure for fuel storage and transportation. Hydrogen is currently stored in tanks as a compressed gas or a cryogenic liquid. Hydrogen can be transported in tanks or the compressed gas can be sent through pipelines. New technologies that store hydrogen in a solid state are being developed that are safer and more efficient than storage as a gas or liquid.

Hydrogen has the potential to be used in a variety of applications to provide fuels or energy in the form of heat and electricity. Hydrogen can be used to power internal combustion engines or turbines which in turn can be used to power vehicles or turn electrical generators. It can be used in stationary fuel cells in homes and businesses to provide a source of heat and electricity. Much of the current focus is on the use of hydrogen as a clean fuel to power fuel cells for a variety of transportation applications.

Electricity Storage Technologies

The lack of cost effective storage technologies is one of the key obstacles to efforts to improve the economics of electric generation by allowing cheaper stored power to meet peak demand instead of extremely expensive peak power. If economical electric storage technologies could be developed and fielded they could also increase the flexibility and reliability of intermittent renewable resources such as solar and wind. Electric storage could also provide power during peak power plant outages.

One of the more promising technologies now being installed is a type of regenerative fuel cell developed by UK-based Innogy Technology Ventures. This system uses a chemical electrolite to convert electrical energy to chemical energy in a reversible process. A demonstration project will install one of these systems for the Tennessee Valley Authority. This utility scale demonstration project is expected to cost approximately $25 million, have a peak capacity of 12 MW and a storage capacity of 120 MWh.

Conclusions

This section provided information about each type of generating resource that could be used in part to meet Minnesota's electric capacity needs by 2010. It discussed costs, potential opportunities, and barriers to deployment that are necessary to evaluate adding new generation of the various types of technologies in Minnesota. One of the important things to keep in mind is that in evaluating new technology, the relevant cost figures are the cost to build a new facility. Comparison of costs should occur among potential new deployments and their costs, not with reference to the costs of existing facilities that were built 20 to 50 years ago. This section attempts to provide the proper context to be able to make that comparison.

In 2001, the legislature provided a significant impetus to further deployment of renewable generation technologies by establishing a renewable technology objective, and requiring utilities to exert good faith efforts to achieve the objective. This objective is designed to achieve a one percent deployment of renewable generation technologies (exclusive of specific mandated renewables that are already being constructed), with a goal of increasing the percentage of energy generated by the renewable resources to 10 percent by the year 2015. In addition, the legislature required a specific portion of the renewable energy generation to focus on biomass energy production technologies. The Department of Commerce will closely monitor the utilities' progress in meeting this objective and may, in the future, recommend adjustments to it.

The Department does strongly urge an increase in the threshold for net metering for distributed generation resources to 2 megawatts. As the discussion of net metering shows, the very low avoided cost rate, combined with the very low threshold for net metering of 40 kilowatts, is a substantial barrier to maximum cost-effective deployment of a variety of distributed generation technologies and combined heat and power technologies at Minnesota's industrial facilities. The MPUC should generically set prices for net metered power between 41 kW and 2 MW. The present statute should be amended to cover 40 kW and below.

Finally, the Department of Commerce and the Pollution Control Agency emphasize that, to the extent that Minnesota invests in more new generation technology in the next ten years than it has in perhaps the last 20 years, policymakers need to consider that the decisions made today will be the technologies, with both their costs and their environmental impacts, for the next 40 to 50 years, or possibly a longer time period than that. As a result, major investments must be made with an eye to long term implications of today's decisions. In particular, policymakers should keep in mind the very promising technology represented by the development of fuel cells and pilot projects in the storage of electricity. Their potential to revolutionize the production of energy, and reduce substantially its environmental effects, in the next 10 to 15 years cannot be overstated.

ENERGY CONSERVATION – THE BEST ANSWER

After that long exposition on electric supply options for meeting Minnesota's increasing demand for electricity, we come to the energy conservation. Even those supply side technologies that do not pollute and potentially can supply a lot of electricity at reasonable cost have downsides like creating a need for large upgrades of transmission systems or simply being in early stages of development and not yet readily available. In addition, all of them require a moderate to large amount of capital investment, which necessarily increases rates to consumers.

Reducing the demand, or at least reducing the rate of growth in demand, has no downside. Energy conservation and greater efficiency in the use of energy, including load management that shifts energy usage to lower demand parts of the day, is easy, costs little, and gives consumers their only opportunity for self-determination in relation to energy.

Two of the primary benefits of energy conservation are intuitive. The first is that consumers have smaller bills for utility service when they use less energy. The second is that by reducing inefficient energy use, Minnesotans experience fewer emissions of pollutants that cause health problems and damage the environment. A kilowatt hour not consumed is one that need not be generated. A kilowatt hour not generated emits no pollutants.

The third benefit, a huge one that is often overlooked, is that good conservation programs reduce rates for all ratepayers on a utility system. When a utility adds a power plant, the costs of the plant are put into the utility's rates as an increased charge per unit of consumption for all ratepayers on the system. If sufficient conservation occurs on the system as a whole, so that a new electric generation unit is avoided or delayed, all ratepayers have rates lower than they would otherwise have had.

The first 20 years of the Minnesota Conservation Improvement Program (CIP) have saved enough energy to avoid building four or five new power plants that would have been funded by rate increases. The current CIP program is saving about 128 MW of demand per year in the service territories of Minnesota's rate-regulated investor-owned utilities, avoiding the need to construct and pay for a 640 MW power plant every five years. These programs are cost-effective in that the energy conservation programs cost ratepayers less than the cost of constructing new generating capacity. For example, the 640 MW were saved at a cost to ratepayers of $357/kW while a coal plant that produced 640 MW would have cost ratepayers $1000-1400/kW.

Last year, the Legislature increased the state's commitment to energy conservation because of its concern over rising energy prices and the need to plan for additional electric capacity. The 2001 legislation made changes to the CIP program that should result in more energy conservation than in the past. The changes increased the spending required for conservation programs by municipal utilities and cooperative electric associations to the same level required of investor-owned utilities, increased the focus of all CIP spending on programs that actually reduce energy use, and established consistent statewide reporting and program evaluation to allow assessment of statewide progress and evaluation of the effectiveness of conservation programs.

The Legislature also required the Department of Commerce to prepare this report on the role of energy conservation in the future and to assess and make recommendations on how to improve the utilities' energy conservation programs. Accordingly, this section discusses energy conservation programs, the impact and cost of energy conservation, and evaluates the CIP Program.

This section will discuss energy conservation primarily as physical improvements that result in less energy consumption and that can be relied on, once they are installed, to continue to use less energy out into the future. Another type of energy conservation is consumer behavior such as setting a thermostat lower or turning off lights in unoccupied rooms, which result in lower bills and system savings, but cannot be relied on in an energy planning sense to provide capacity in the system for the long term. The line between physically reliable system improvements and less reliable, but very important, conservation behaviors is sometimes blurry. For example, energy efficient equipment must often be operated properly to ensure in reality the energy savings of which it is capable.

Energy Conservation Programs

Energy conservation, for the purposes of this report, refers to investments that reduce the amount of energy needed to provide a service. The service (e.g., cooling a house, heating water) continues at equal or even higher quality despite the drop in energy use. An example of energy conservation investment is the purchase of an Energy Star refrigerator which uses at least 10 percent less energy than required by national appliance standards.

ENERGY STAR

ENERGY STAR designation was introduced by the U.S. Environmental Protection Agency (EPA) in 1992 as a voluntary labeling program designed to identify and promote energy-efficient products. EPA partnered with the U.S. Department of Energy in 1996 to promote the ENERGY STAR label, with each agency taking responsibility for particular product categories. ENERGY STAR has expanded to cover new homes, most commercial buildings, residential heating and cooling equipment, major appliances, office equipment, lighting, consumer electronics, and other products. U.S. DOE has chosen October 2001 as a focus month for ENERGY STAR lighting with compact fluorescent lamps (CFLs) and titled its promotion "Change a Light, Change the World."

If all consumers, businesses and organizations in the United States made product choices and building improvement decisions using ENERGY STAR products and methodologies over the next decade, the national energy bill would be reduced by about $200 billion each year. The ENERGY STAR label is increasingly being used as a simple way to help customers find and choose energy efficient products. CIP programs offer rebates for purchasing energy efficient products, increasing the products' attractiveness to consumers.

Organizations are working together to influence manufacturers to produce more energy efficient products and to educate and motivate customers to purchase them. For example, the Midwest Energy Efficiency Alliance (MEEA), a regional network of organizations collaborating to promote energy efficiency, formed in 1999. MEEA's mission is to foster increased market penetration of existing energy-efficiency technologies and promote new technologies, products and best practices. The Department of Commerce (DOC) is a member of MEEA. The DOC's State Energy office Manager serves on the MEEA Board as Vice-Chair.

MEEA is working with the DOC and several Minnesota utilities to promote energy conservation. MEEA is also working with regional representatives of retail chains like Sears, Home Depot and True Value Hardware to encourage them to stock and promote ENERGY STAR products. By encouraging the promotion of energy conservation campaigns on a statewide, region-wide or even nation-wide basis, groups like MEEA and ENERGY STAR are helping to ensure that consumer demand is permanently transformed to focus on buying mostly energy-efficient products.

Building Recommissioning and Building Design Assistance

Two new energy conservation strategies promise to provide significant energy savings for Minnesota's commercial and industrial energy consumers. The first, building recommissioning, involves investigating existing buildings to ascertain whether the building's systems are operating properly. Skilled auditors often find that controls have been disengaged, ductwork has been pierced, or other systems are not functioning. The second strategy, design assistance, involves improving architectural plans for new buildings so that the buildings are more efficient than the energy code. Xcel Energy's *Energy Assets* project is an example of design assistance. Xcel's prime contractor, the Weidt Group of Minnetonka, received an international award in 2001 for the project from the European Council for an Energy Efficient Economy (ECEEE).[70] The DOC encourages other utilities to adopt these approaches when appropriate as part of their CIP programs.

In the 2001 legislative session, Minn. Stat. §16B.325 was amended to require the Departments of Administration and Commerce to develop sustainable building design guidelines for all new state buildings by January 15, 2003. One of the primary objectives of these guidelines is to ensure that all new state buildings have an energy performance at least 30 percent better than buildings built under the existing energy code as well as encourage continued energy conservation improvements and indoor air quality standards that provide healthy working environments. These guidelines will be mandatory for all new buildings receiving funding from the state bond proceeds fund after January 1, 2004.

Sales Tax Exemptions

In the 2001 special legislative session, Minn. Stat. §297A.67 was amended to include a sales tax exemption for certain energy-efficient products. Products that qualify for this sales tax exemption are:

> residential lighting fixtures and compact fluorescent bulbs with ENERGY STAR labels;
> electric heat pump hot water heaters with an energy factor of at least 1.9;
> natural gas water heaters with an energy factor of at least 0.62;
> natural gas furnaces with an AFUE (efficiency rating) greater than 92 percent; and
> photovoltaic devices.

This sales tax exemption is effective for qualifying products purchased between August 1, 2001 and July 31, 2005. This list could and should be amended to include large appliances with ENERGY STAR labels.

Impact and Cost of Conservation Improvement Program

[70] The project was awarded "The Program Most Likely to Meet the Intent of the Kyoto Protocols in the Shortest Time."

The CIP Program, enacted by the legislature in 1982, is the primary Minnesota energy conservation program. CIP requires Minnesota's electric and natural gas utilities to spend a percentage of their annual income on programs to encourage conservation among all their customers – residential, commercial and industrial – with specific attention to providing conservation opportunities for low-income residential users.

Under CIP, investor-owned utilities (IOUs) submit their conservation projects to the Department for approval. From 1997 to 2000, electric IOUs have spent $171.1 million in CIP, for an average of $42.7 million a year. Gas IOUs have spent $57.4 million, or an average of $11.5 million a year. Five-year energy savings from these projects have totaled 1,680,843 MWh (an average of 336,169 MWh a year) and 4,665,206 Mcf of natural gas (an average of 933,623 Mcf a year). Electric demand savings have totaled 641 MW (an average of 128 MW a year), with a cost of $357 per kW of capacity saved.

CIP programs have helped Minnesota avoid significant amounts of utility investment in energy and demand. Conservation investments by Minnesota's investor-owned utilities' under their 1996-2000 CIP programs will result in the saving of 16.8 billion kWh (enough electricity to power more than 2 million Minnesota homes for a year) at an average cost of 1.4 cents per kWh. Natural gas savings total 85 million Mcf, enough natural gas to supply energy to 772,925 average Minnesota homes for a year at a cost of only $0.68 per Mcf.

Recent changes in energy price volatility and Minnesota legislation are likely to result in higher savings in the future. In 2000, natural gas prices skyrocketed. Although natural gas prices have recently leveled off at much lower levels, it is expected that the future cost of energy will be higher, and certainly more volatile, than it has been in the past decade. Consequently, energy conservation investments are more cost-effective than in the past and consumers are more aware of their energy costs and are interested in ways to save energy. In response, the potential for energy conservation to make larger inroads is greater than it has been in the recent past.[71]

In addition to the investor-owned utilities, all of Minnesota's rural electric cooperative associations and the municipal electric utilities that generate all or a part of their electric power also have been required to invest a portion of their revenues in load management and energy conservation activities. For the most part, the municipal and cooperative utilities have concentrated their investments in load-management activities and consumer education, with some of the larger utilities making some forays into providing energy savings programs. In the future, however, the 2001 legislation

[71] A downturn in the U.S. economy followed the large energy price increases. The worsening of economic conditions will reduce the ability of some consumers to invest in efficient products. It is difficult to predict what net impact this will have, but it does make rebate programs more important in encouraging conservation.

requires municipal and cooperative utilities to implement more energy-saving programs.

Since energy conservation often costs less than the supply-side investments of utilities, reduces society's costs of energy services, and has no negative environmental impacts, energy conservation should be promoted to the maximum, reasonably achievable, level.

Figure 3-25 shows estimates of the amount of electric and energy and demand and natural gas energy that the state can achieve by 2010 just through utility-sponsored energy conservation programs.[72] Figure 3-25 assumes that municipal and cooperative utilities ramp up their commitment to energy conservation projects as specified in the 2001 energy legislation.

When each utility submits its forecast of future energy needs to MAPP, the forecast already accounts for the fact that the companies' energy conservation projects will reduce their customers' energy and demand needs in the future. Consequently, Figure 3-25 estimates overall potential energy conservation in the state. It cannot be used to estimate how much energy conservation can be used to reduce the need for new electric capacity and energy in the state.

The contribution of energy conservation to the state's energy and capacity needs for 2010, as identified by MAPP, could be increased in other ways:

> Increase the percentage of municipal and cooperative utilities' CIP spending that must be used on energy conservation projects to higher than 50 percent.
>
> Increase the percentage of gross operating revenues that all municipal, cooperative and IOU utilities must spend on CIP to 2 percent (the amount required of Xcel Energy).

These steps could save an additional 65-85 MW of capacity and an additional 200 to 300 Gwh of electric energy. These strategies could be considered in future legislative sessions.

Achieving the estimated goals requires the following actions:

> Setting a statewide goal and monitoring our ability to attain it.
>
> Assisting all utilities, especially municipal and cooperative utilities, in identifying, developing and delivering projects that conserve energy.

[72] The amount of load-management demand reductions from utility programs is not included.

Continuing to provide financial incentives for investor-owned utilities' investments in cost-effective energy conservation.

The state should set explicit statewide energy and capacity savings goals to enable us to determine whether conservation laws and policies are attaining their objectives and to provide a benchmark for determining whether statutes should be further modified. The goals should be those shown in Figure 3-25. DOC will monitor and report on the state's progress in meeting those goals on a regular basis.

Municipal and cooperative utilities' increased investment in energy-saving projects offers an opportunity for the state to reduce the cost of attaining future energy needs. DOC is spearheading a joint effort with the municipal and cooperative utilities to identify the projects that have higher energy-saving potential. The first meeting associated with this effort included representatives from the cooperative electric utilities, municipal utilities, MEEA, and the state of Wisconsin. The group identified the following promising projects:

<u>Commercial and Industrial Customers</u>
Lighting
Air Compressors
Motors and Adjustable Speed Drives
Refrigeration

<u>Residential Customers</u>
ENERGY STAR appliances and lighting
Low-income appliance changeout

In addition, the municipal and cooperative utilities are consulting with Minnesota and national-based energy service companies, and Minnesota and other states' municipal and cooperative utilities that have implemented successful programs.

To help overcome the inherent conflict that IOUs have, being required to both save and sell energy, the Public Utilities Commission has approved financial incentives for efficient utility CIP investments. Currently, the electric and natural gas IOUs receive higher incentives when their energy conservation investments result in a higher value of avoided energy and capacity. DOC continues to monitor the financial incentives to see where adjustments are needed. However, since the natural gas and electric utilities continue to meet and surpass their approved goals, the incentives appear appropriate at this time.

The current CIP program creates an inherent conflict in that it requires utilities to promote energy consumption to increase sales but also are required to run programs to conserve energy. To eliminate this conflict, three states, New York, Vermont and

Wisconsin, established what is called a conservation utility. A conservation utility differs from the current CIP structure in that the administration of energy conservation programs is handled by an entity with the sole purpose of saving energy without the inherent conflict of losing profits by reducing sales. For example, in Vermont a state agency put out to bid the administration of the state's entire conservation program. The winning bidder is currently contracting with other organizations to deliver the programs.

A conservation utility can be designed so that it delivers programs statewide, when appropriate, or target specific projects, marketing approaches, etc. to specific regions of the state. DOC recommended movement towards a conservation utility in its 2000 *Keeping the Lights On, Securing Minnesota's Energy Future* report. We continue to strongly urge reorganization of the CIP structure to establish an independent conservation utility, perhaps incrementally starting with funds for low-income CIP programs.

CIP Program Evaluation

The 2001 legislature requires DOC to study the Conservation Improvement Program created under Minnesota Statutes, section 216B.241. The main goal of the study is to make recommendations to the legislature on changes that will enable CIP investments to maximize energy savings. The study must include ways of reducing administrative costs, suggestions for how to target CIP investments towards projects with high potential for saving energy, and recommendations concerning the program's appropriate levels of spending and investment.

Program Costs

Both DOC and utilities incur CIP administrative costs. These costs include:

> The cost to utilities to research, plan for, and submit for approval new and existing project proposals.
>
> The cost of DOC and other parties' review of the submitted proposals.
>
> The cost of compliance filings.

Another cost of the process is the lost opportunities created when approval is delayed due to failure of the utility or third party to provide adequate information upfront or slow response to discovery requests and the consequent extra time required by analytical staff or the Commissioner.

DOC has taken several actions during the past five years to reduce the resources consumed by the CIP approval process and to expedite decisions. These steps include:

setting timelines for when staff review must be completed,

exempting readily available information from filing requirements,

eliminating an independent cost-effectiveness analysis of individual projects, concentrating on utility inputs into modeling of cost-effectiveness and questionable projects instead,

granting utilities the flexibility to modify projects or surpass goals when the changes result in a cost-effective project,

reviewing utility proposals at a customer class level instead of an individual project level, and

reducing the amount of analysis of existing, successful projects.

In response, most of the CIP filings have been handled in a timely manner and the number of time-consuming miscellaneous filings has been reduced.

Currently, IOUs' conservation improvement programs are approved once every two years. Despite attempts to streamline the process, the submission and approval of a plan consumes a significant amount of DOC's, utilities' and other parties' resources. Allowing utilities to file for and implement programs for three years is one way to reduce CIP's administrative burden. The drawback may be that it could be difficult to estimate budgets and goals three years into the future and that technologies and standards may change.

DOC's review of individual electric utility projects shows that the most cost-effective ones are the conservation projects that the municipal and cooperative utilities have been recommended to pursue. Figure 3-26 shows the most cost-effective commercial and industrial projects as ranked by the cost of saving energy. Figure 3-27 shows the most cost-effective commercial and industrial projects as ranked by the cost of saving demand. Figure 3-28 shows the most cost-effective residential projects.

Note that although a few project costs may appear high compared to the price of only the cost of one kWh produced or of installing one kW of capacity, they are still cost-effective because the projects provide (i.e., they avoid) both energy and capacity. The combination of the two attributes make the projects cost-effective.

Figure 3-29 shows the same information for natural gas projects.

The benefit of gathering this information is that it can be shared with all of the utilities in the state when they are assessing which projects to pursue.

State law requires several different levels of spending for Minnesota's utilities. The percentage of gross operating revenues devoted to energy conservation (and not load management) varies according to whether they are natural gas or electric, whether they are IOU or non-IOU, and whether they own a nuclear generating plant (Xcel Energy) or not. Significantly more cost-effective energy conservation could be obtained to meet the state's needs than will be attained by the present spending requirements. For example, Xcel Energy's and Alliant's most recent electric integrated resource plans indicate that they should procure more energy conservation than may be attainable at their statutory spending levels (2 percent and 1.5 percent of gross operating revenues, respectively). As a result, the Public Utilities Commission has recently approved higher energy conservation targets for both Xcel and Alliant. A change in the statutory spending requirements is not needed to ensure that these two utilities attain higher energy and demand savings goals, but could be considered for other utilities as well.

Although the municipal and cooperative utilities are required to devote higher percentages of their CIP spending to energy conservation projects than they have historically, experience shows that it takes time to build up effective energy conservation projects. The most prudent course of action is to assist these utilities in expeditiously implementing the most cost-effective energy conservation projects and to assess each year how they are performing.

Based on our review of the role of energy conservation in the state and the efficiency of the existing CIP program:

> 2010 energy conservation goals of 1,000 MW; 3,000 GWh; and 10,500,000 Mcf should be established.
>
> DOC should work with municipal and cooperative utilities in conjunction with regional and national entities to facilitate the establishment of new conservation programs that comply with the new energy legislation.
>
> All utilities should promote ENERGY STAR projects.

Conclusion

This section has thoroughly reviewed the Conservation Improvement Program, and shown that, so far, the program has provided substantial energy savings in a manner that is much less costly than the deployment of any of the energy generation technologies discussed in the prior section of this chapter. This section also noted that the legislature made significant positive changes in the Conservation Improvement Program statutes in the 2001 session to assure that conservation programs will be even more effective in the future. At this time, DOC recommends that the policy initiatives enacted in 2001 be fully implemented and that DOC track progress in meeting the conservation goals articulated in this report, and regularly report back to the legislature on the that progress. If problems arise, DOC will make recommendations for program administration or statutory changes that would keep the state on track in meeting these goals. In addition, we strongly recommend establishment of one or more independent conservation utilities to administer conservation dollars. To begin, the CIP dollars dedicated to projects for low-income households should be centralized and administered in conjunction with U.S. DOE low-income weatherization dollars.

Figure 3.1: Fuel Used to Generate Electricity to Serve Minnesota, 2000

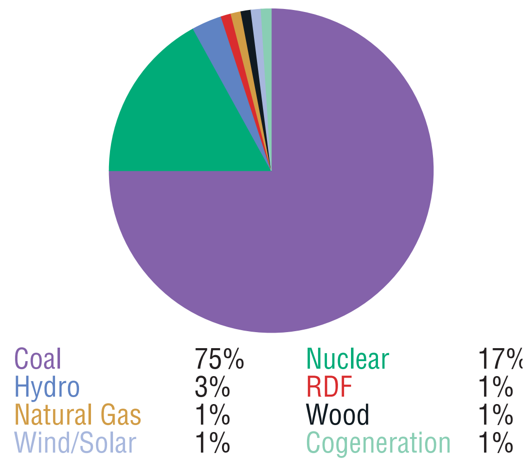


Figure 3.2: Relative Emissions from Electric Utilities Nationally, 1999

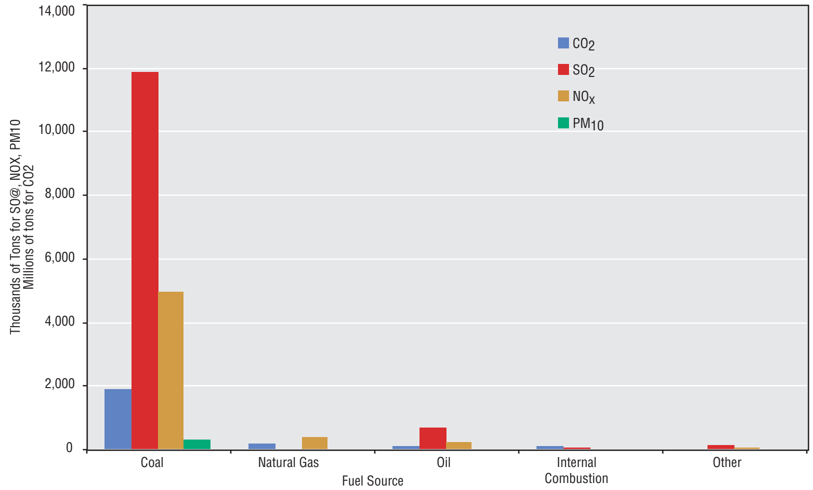


Figure 3.3: New Electric Generation Projects in Process

Project	Location	Type	Year	Size	Fuel
Under Construction (139 MW)					
Black Dog _	Dakota County	Intermediate	2002	114 MW	Gas
District Heating	St. Paul	Baseload		25 MW	Waste Wood
Approved Purchased Power Agreement (PPA) (100 MW)					
EPS/Beck		Baseload		50 MW	Whole Trees
FibroMinn	Benson	Baseload		50 MW	Turkey Litter
Won All-Source Bid, PPA Pending (250 MW)					
Navitas/NEA		Intermediate Peaking		50 MW 250 Gas	Wind
Application Expected (225 MW)					
Rapids Power LLC	Grand Rapids	Baseload	2005	225 MW	Coal, Wood
Other (268 MW)					
Bid Selection in Process by Xcel Energy		Intermediate		80 MW	Wind
LTV Power Plant	Taconite Harbor	Baseload		188 MW	Coal

Figure 3.4: Annual Emissions of SO_2, NO_X and CO_2 from New 500 MW Baseload Generating Units[a]

Plant Type	Fuel Used	Thermal Efficiency	Net Generation (MWH/year)	Cost[a] ($/kW)	Annual Emissions (Tons/year)[b] SO_2	NO_X	CO_2
Natural Gas Combined Cycle	Gas	0.55	2,847,000	$375-600[1]	79	79	1,027,085
Pulverized Coal/Steam Turbine	Coal	0.33	2,847,000	$1,092-$1,219[2]	2,502	1,177	3,136,433
Circulating Fluidized Bed/Steam Turbine	Coal	0.42	2,847,000	$920-$1,306[2]	1,966	809	2,464,340
Integrated Gasification Combined Cycle	Coal	0.38	2,847,000	$1,200-$1,400[3]	1,534	703	2,723,744
Existing Pulverized Coal/Steam Turbine[4]	Coal	0.30	2,847,000		16,204	12,153	3,450,076

[a] calculated using a 65% plant capacity factor
[b] assumes that all new facilities meet New Source Performance Standards and Best Available Control Technology standards
NOTE: Data for the Integrated Gasification Combined Cycle technology are based on the operation of two facilities. Those facilities participated in the U.S. Department of Energy's Clean Coal Technology program.
[1] Actual costs of recent Minnesota Projects
[2] Annual Energy Outlook 2001, Table 43, EIA and Docket No. IP4/CN-01-1306 (Rapids Power) (1999 dollars)
[3] Figures used by the World Bank, www.worldbank.org/fpd/em/power/sources/svc_coal.stm.
[4] Emission rates representing performance of a non-NPSP Minnesota pulverized coal generating unit: 1.0 lb/mmBtu SO2, 0.75 lb/mmBtu NOx

Figure 3.5: Electric Utility Contribution to Current Minnesota Air Emissions

	1999 Emission to the Air (thousand tons)	% of Estimated Statewide Emissions
Greenhouse Gases	35,982	26%
Nitrogen Oxides	87	18%
Sulfur Dioxide	95	58%
Carbon Monoxide	8	<1%
Fine Particulate Matter (2.5 microns)	?	large
Lead	0.03	62%
Mercury	0.0008	40%
Other Metals (Chromium, Arsenic, Nickel)	NA	10-60%

Source: PCA

Figure 3.6: Nonnuclear Baseload or Intermediate Load Electricity Generating Units at Plants Larger than 100 Megawatts

	Capacity (summer) (MW)	Principal Fuel	Load Type	Start-up Datel	NSPS Status Vintage (Year)
Xcel Energy					
Sherburne County					
unit 1	712.0	coal	Baseload	1976	n/a
unit 2	721.0	coal	Baseload	1977	1976
unit 3	871.0	coal	Baseload	1987	1986
Allen King	571.0	coal	Baseload	1958	n/a
Riverside					
unit 7	150.0	coal	Baseload	1987	1986
unit 8	221.5	coal	Baseload	1964	n/a
High Bridge					
unit 5	97.0	coal	Intermediate	1956	n/a
unit 6	170.0	coal	Intermediate	1959	n/a
Black Dog					
unit 3	113.2	coal	Intermediate	1955	n/a
unit 4	171.8	coal	Intermediate	1960	n/a
XCEL total	3,959.6				
LSP Cottage Grove	252.1	gas	Intermediate	1998	1997
Rochester Publ. Util.					
Silver Lake					
unit 4	60.3	coal	Intermediate	1969	n/a
Minnesota Power					
Clay Boswell					
unit 1	69.0	coal	Intermediate	1958	n/a
unit 2	69.0	coal	Baseload	1960	n/a
unit 3	346.3	coal	Baseload	1973	n/a
unit 4	535.0	coal	Baseload	1980	1979
Syl Laskin					
unit 1	55.0	coal	Baseload	1953	n/a
unit 2	55.0	coal	Baseload	1953	n/a
subtotal	110.0				
Minnesota Power total	1,129.3				
OtterTail Power					
Hoot Lake					
unit 2	64.9	coal	Intermediate	1959	n/a
unit 3	84.0	coal	Intermediate	1964	n/a
Otter Tail Power total	156.9				
Minnesota Total	**5,355.7**				

Figure 3.7: Emission Rates Per Unit of Electricity Generated at Minnesota Electric Generating Plants

	Emission Rate (lb./kWh generated)				Primary Emission Controls[a,b]	
	NOx	SO2	CO2	Hg	SO2	NOx
Xcel Energy						
Sherburne County	0.003	0.003	2.39	0.00000006	scrubbers	LNC, LNB
Allen King	0.011	0.017	2.10	0.00000002		
Riverside	0.011	0.012	2.11	0.00000003		
High Bridge	0.007	0.005	2.46	0.00000005		
Black Dog	0.010	0.004	2.60	0.00000003		
Minnesota Power						
Clay Boswell	0.004	0.006	2.34	0.00000005	scrubbers	LNC
Syl Laskin	0.006	0.004	2.27	0.00000007		
Otter Tail Power						
Hoot Lake	0.004	0.008	2.77	0.00000005		LNB
Rochester Publ. Util.						
Silver Lake	0.007	0.021	1.78	0.00000004	1	
LSP Cottage Grove	0.0002	0.000	0.94	NA		SCR

[a] LNC1 = low NO_x coal and air nozzles with close coupled overfire air; LNC2 = low NO_x coal and air nozzles with separated overfire air.
[b] low NOx controls 1 at Sherburne County unit 1 and low NO_x controls 2 at Sherburne County unit 2. Wet scrubbers at Sherburne County units 1 and 2 and Clay Boswell unit 4, dry lime scrubbers at Sherburne County unit 3.

Figure 3.8: Principal Heath and Environmental Impacts of Air Pollutants Emitted From Coal-Fired Power Plants

Pollutant	Effects	Geographical Scope of Effect*
Sulfur Dioxide	Respiratory disease, acidification, crop losses, visibility impairment	Local, regional
Nitrogen Oxides	Respiratory disease, acidification, crop losses, visibility impairment, eutrophication	Local, regional
Particulate Matter	Respiratory and cardiac disease, visibility impairment	Local, regional
Mercury	Central nervous system disease	Local, regional, global
Metals	Various - depends on the metal	Local, regional
Secondarily formed pollutants		
•SO_4 from SO_2	Acidification	
•NO_3 from NO_x	Acidification, eutrophication	
•$PM_{2.5}$ from SO_2 and NO^X	Respiratory disease, death, visibility impairment	
•Ozone from NO_x	Respiratory disease, visibility impairment	Local, regional
Carbon Dioxide	Climate change	Global

*Local: Within 100 miles; Regional: Within 1,000 miles

Figure 3.9: Estimated Extra Annual SO_2, NO_X and CO_2 Emissions Associated with Permitted or Planned Expansions to Service or Capacity Added Since 2000

Plant Name	Generation Capacity (Summer) (MW)	Capacity Factor (%)	Net Generation (MWH/yr)	Efficiency in Converting Fuel to Electricity	Emissions SO_2 (tons)	Emissions NO_X (tons)	Emissions CO_2 (Tons)
Pleasant Valley units #1-3	434	5	190,092	0.34	1	18	110,934
Lakefield Junction units #1-6	480	5	210,240	0.34	1	20	122,692
New Ulm unit #7	22	5	9,636	0.34	0	1	7,717
Cascade Creek units #3-4	50	5	21,900	0.34	0	2	12,780
Potlatch Cloquet unit #8	24	65	136,656	0.32	0	66	84,734
Navitas gas turbine	250	5	109,500	0.34	1	10	63,902
St. James Diesel Plant units #1-7	12	5	5,256	0.25	9	117	5,725
Worthington Diesel Plant units #1-6	14	5	6,132	0.25	10	136	6,679
Black Dog units #2,5	143[a]	45[c]	1,144,757	0.5	-28[d]	-41[d]	435,075[d]
District Energy unit #7	25	65	142,350	0.2	39	182	61,668
Heartland Energy and Recycling	4	65	22,776	0.2	7	14	36,824
Fibrominn Biomass Power Plant	50	65	284,700	0.22	155	353	-
Northome Biomass Plant	15	65	85,410	0.26	14	56	-
Perham Resource Recovery	2.5	65	14,235	0.2	2	36	11,746
Grand Rapids power plant	195[b]	65	1,110,330	0.42	767	316	625,590
Total	**1720.5**		**3,493,970**		**978**	**1,286**	**1,586,066**

[a] net increase in generation capacity after conversion of existing unit 2 to combined cycle gas turbine, retirement of existing unit 1, and addition of unit 5. [b] net increase in generation capacity after subtraction of internal Blandin demand. [c] 45% capacity factor at 290.4 MW of capacity at repowered unit #2 and new unit #5. [d] estimated emissions at repowered unit #2 and new unit #5 less 1999 emissions from old units #1 and 2.

NOTE: In addition, approximately 3,020 tons of existing SO_2 emissions, 2,849 tons of existing NO_X emmissions and 1,215,921 tons of CO_2 would be shifted from the industrial sector to the electricity generation sector with the conversion of the 187.7MW LTV-Taconite Harbor plant to a generating facility serving the grid.

Figure 3-10: Estimated Rate Impact of Installing SO2 Controls on Plants (Low-Cost Technology to Meet NSPS)

Model Number	Facility	Annual 2000 Residential MWH Usage[1] (a)	Baseload Cost Per MWH Per MWH 2000 $[2] (b)	Annual Baseload $ Cost per Residential Customer[3] (c)	Intermediate Load Cost Per MWH 2000 $ (d)	Annual Intermediate Load Residential Customer[4] (e)
1	Clay Boswell 2	8.32	1.2381	10.30	1.1924	9.92
2	Hoot Lake 2	10.23	2.3816	24.35	2.2743	23.25
3	High Bridge 6	7.78	0.4802	3.74	0.4612	3.59
4	A.S. King	7.78	1.3804	10.74	1.3316	10.36
5	Clay Boswell 3	8.32	3.4615	28.79	3.2970	27.42

Assumes that these additions do not lengthen the life of the facility. Longer life would reduce the annual costs.

[1] MN Jurisdictional Annual Report

[2] Sheet 1

[3] column (a) times column (b)

[4] column (a) times column (d)

Figure 3-11: Estimated Rate Impact of Installing NOX Controls on Plants (Low-Cost Technology to Meet NSPS)

Model Number	Facility	Annual 2000 Residential MWH Usage[1] (a)	Baseload Cost Per MWH Per MWH 2000 $[2] (b)	Annual Baseload $ Cost per Residential Customer[3] (c)	Intermediate Load Cost Per MWH 2000 $ (d)	Annual Intermediate Load Residential Customer[4] (e)
1	Clay Boswell 2	8.32	0.3140	2.61	0.3044	2.53
2	Hoot Lake 2	10.23	0.8151	8.33	0.7699	7.87
3	High Bridge 6	7.78	0.1313	1.02	0.1313	1.02
4	A.S. King	7.78	0.3543	2.75	0.3363	2.62
5	Clay Boswell 3	8.32	0.4545	3.78	0.4160	3.46

Assumes that these additions do not lengthen the life of the facility. Longer life would reduce the annual costs.

[1] MN Jurisdictional Annual Report

[2] Sheet 1

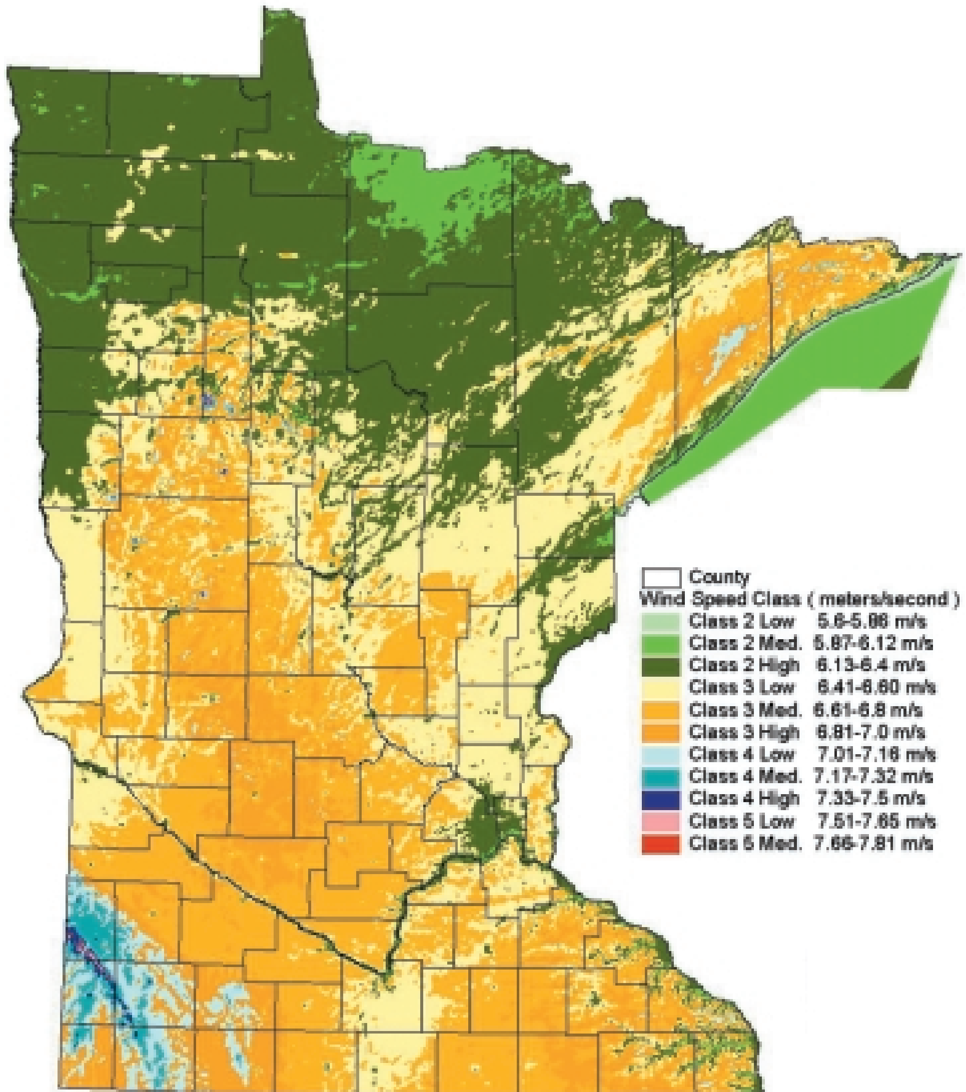
[3] column (a) times column (b)

[4] column (a) times column (d)

Figure 3.12: Largest Hydropower Projects Located in Minnesota, 1998

		MW
Thompson	MP	72.6
Blanchard	MP	18
Fon Du Lac	MP	12
Hennepin Island	Xcel	12

Figure 3.13: Minnesota's Wind Resource by Wind Speed Class



Source: Wind resource analysis using the WindMap program. Values shown in northeast Minnesota may not be representative due to a lack of data for this part of the state.

Figure 3.14: Wind Power Development in Minnesota

Nearest City	Developer	Date	MW	Affiliated Electric Utility
Marshall	Navitas Energy	1992	0.6	Marshall Municipal Utility
Buffalo Ridge	Kenetech Windpower	1994	24.82	Xcel Energy
Chandler (I)	enXco, PRC	1998	1.98	Great River EnergyG
Lake Benton (I)	Enron Wind Corp.	1998	107.25	Xcel Energy
Woodstock	Edison Capital	1999	10.2	Xcel Energy
Moorhead (I)	Moorhead Public Service	1999	0.75	Moorhead Public ServiceG
Hendricks	Navitas Energy	1999	11.25	Xcel Energy
Lake Benton (II)	FPL Energy	1999	103.5	Xcel Energy
Hendricks	Navitas	1999	11.88	Xcel Energy
Elk River	Navitas Energy	2001	0.66	Xcel Energy
Ruthton	Navitas Energy	2001	14.52	Xcel Energy
Hendricks	Navitas Energy	2001	11.88	Xcel Energy
Averill	Navitas Energy	2001	1.98	Xcel Energy
Chandler (II)	enXco, PRC	2001	3.96	Great River EnergyG
Total Installed			307.28	
Estimated homes/yr	107,671*			
Planned Installations				
Wilmont	Navitas Energy	2001	0.9	SMMPAG
Moorhead (II)	Moorhead Public Service	2001	0.75	Moorhead Public Service
Murray/Pipestone County	Navitas	2001	79.5	Xcel Energy
Murray County	EnXco	2001	79.5	Xcel Energy
Hendricks	Navitas Energy	2001	0.9	Otter Tail PowerG
Hendricks	Navitas Energy	2001	1.8	Xcel Energy
Murray/Pipestone County	Navitas Energy	2001	51	Xcel Energy

∑ Navitas Energy, formerly Northern Alternative Energy

∑ PRC: Project Resources Incorporated

∑ Xcel Energy, formerly Northern States Power Company, is mandated to construct 425 MW of wind power by the end of 2001 and an additional 400 MW by 2012. All Xcel Energy Projects are applied to the mandate.

∑ G Green power program.

Figure 3.15: Cost of Wind Power (¢/KWh), 1981-2005

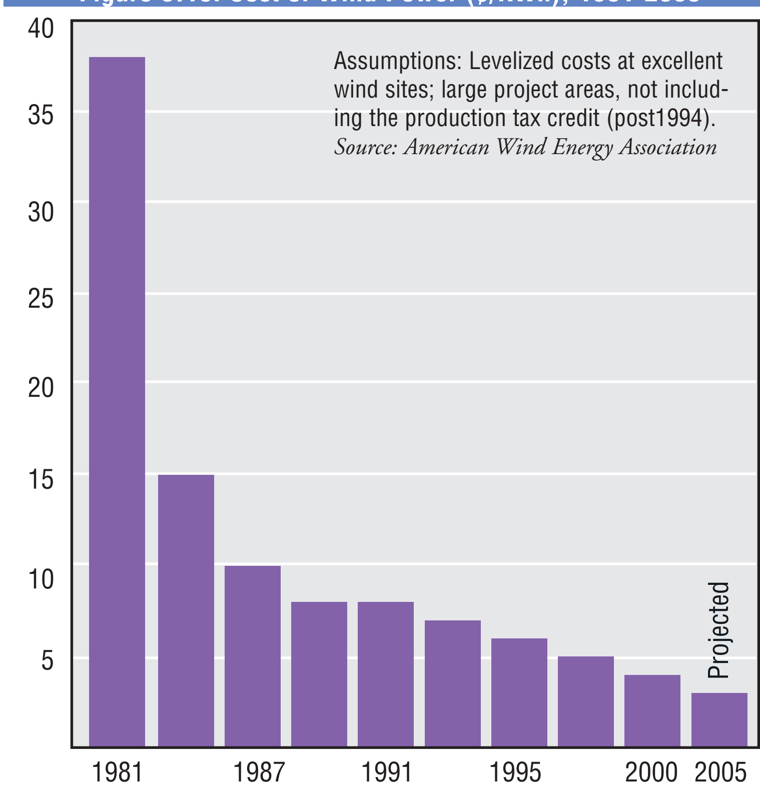


Figure 3.16: Wind Project Costs, 1996-2001

Location	Year	Size	Cost
Vermont	1996	6MW	$1650/KW
Iowa	1999	193MW	$1250/KW
Woodstock, MN	1999	10MW	$1250/KW
Hendricks, MN	1999	12MW	$1425/KW
Hendricks, MN	1999	11MW	$1350/KW
Texas	1999	34MW	$1176/KW
Texas	2001	125MW	$880/KW

Figure 3-17: Comparison of Bioenergy Fuels to Coal for CO_2, SO_2 and NO_x

Facility	CO_2 lb/mmBtu	SO_2 lb/mmBtu	NO_x lb/mmBtu	CO_2 lb/mmBtu	SO_2 lb/kwh	NO_x lb/kwh
Pulverized Coal (Taconite Harbor)	213	1.2	0.08	2.2	0.0024	0.0008
Wood (District Energy)	51	0.032	0.15	0.87	0.005	0.0026
Poultry Litter (Fibrominn)	0	0.07	0.16	0	0.0011	0.0025
Animal Waste Digester gas/IC Engine	0	0.001	0.23	0	0.004	1

Figure 3.18: Annual Average Solor Insolation, 1998-2000

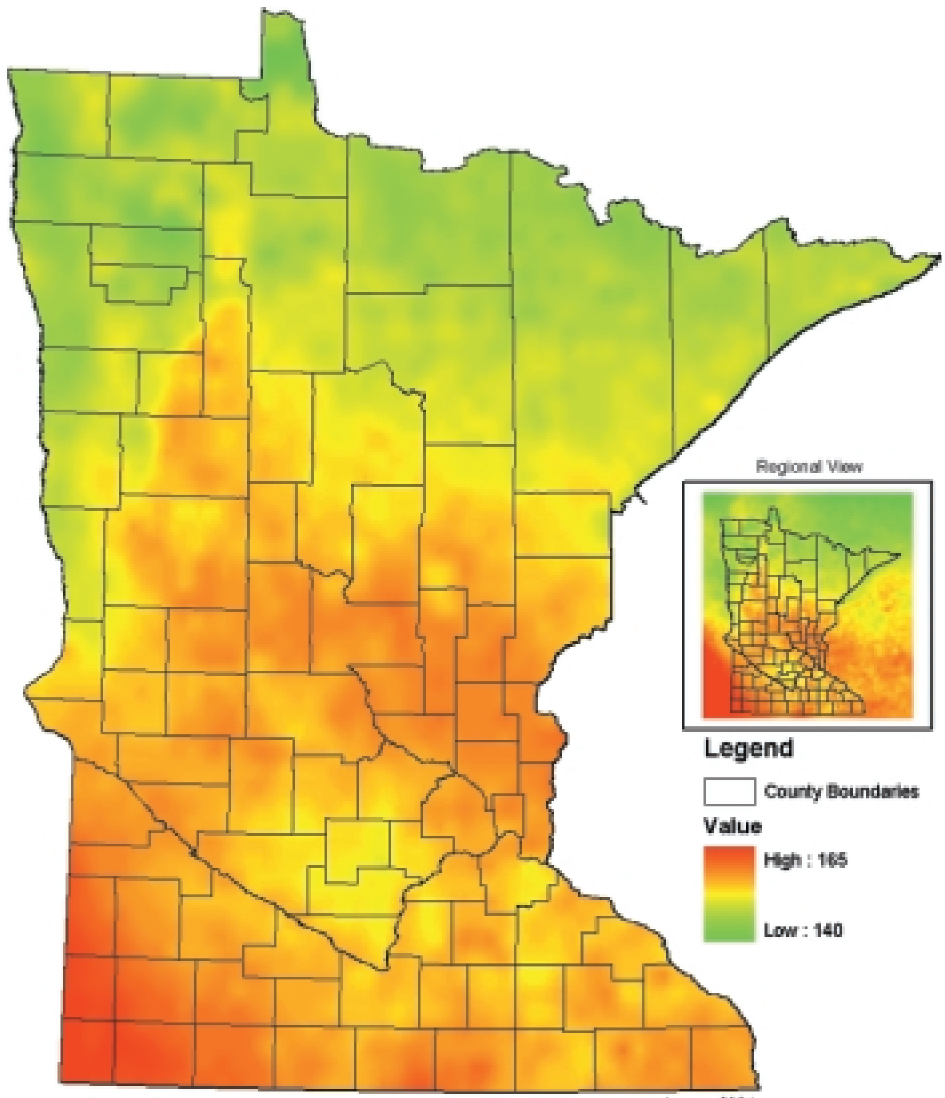


Figure 3.19: Regional and National Photovoltaic Estimated Electric Production

Regional	kWh/kW/yr	National	kWh/kW/yr
International Falls	1,497	Seattle, WA	1,225
LaCrosse, WI	1,547	New York, NY	1,528
Rochester	1,575	Jacksonville, FL	1,623
Fargo, ND	1,613	Phoenix, AZ	2,037
Minneapolis, MN	1,621		
Mason City, IA	1,638		
Sioux Falls, SD	1,652		

Source: NREL

Figure 3.20: Relative Emissions from Various Distributed Generation Sources

Techology	Pollutant, lb/MMBtu			
	NOx	CO2	CO	SO2[b]
Microturbine[a]	0.21-0.4	119	0.11	0.0006
Internal combustion engine (natural gas)[c]	1.94	110	0.353	0.00059
Internal combustion engine (diesel)[c]	4.41	164	0.95	0.29
Internal combustion engine (landfill gas)[d]	0.6	0[g]	0.6	0.01
Internal combustion engine (digester biogas)[e]	0.23	0[g]	0.58	0.001
Fuel Cell[a f]	0.003	1	--	0.0204
Wind	0	0	0	0
Solar photovoltaic	0	0	0	0

[a] Data from U.S. Installation, Operation, and Performance Standards for Microturbine Generator Sets, Borbely-Bartis et al, August 2000, Prepared for the US DOE under Contract DE-AC06-76RL01830)
[b] Sulfur dioxide emissions will vary depending on fuel sulfur content.
[c] EPA AP-42 emission factors uncontrolled.
[d] Values from MPCA database.
[e] Data from P. Lusk, Methane Recovery from Animal Manures: The Current Opportunities Casebook. National Renewable Energy Laboratory, September 1998.
[f] Values here are representative of fuel cell with a reformer using methane or more complex carbohydrate.
[g] CO2 emissions from renewable fuels are counted as zero because emissions are rapidly offset by growth of biomass in subsequent years.

Figure 3.21: Cost of Power Outages

Industry	Average Cost of Downtime Per Hour
Cellular Communications	$41,000
Telephone Ticket Sales	$72,000
Airline Reservations	$90,000
Credit Card Operations	$2,580,000
Brokerage Operations	$6,480,000

Figure 3.22: Waste Combusters that Generate Electricity, 1999

Company/Location	MW	Utility Sold To	Type
Xcel Red Wing	21.3	Xcel	RDF
Xcel Wilmarth	22	Xcel	RDF
Great River-Elk River	42.1	Xcel	RDF
Hennepin County	38	Xcel	Mass Burn
Olmsted County	4.7	Rochester Public Utility	Mass Burn

Figure 3.23: Landfill Gas Systems that Generate Electricity, 1999

Location	MW	Sales to
Pine Bend	12	Xcel
Burnsville	4.2	Xcel
Flying Cloud	4.8	Xcel
Elk River	.5	Conexsus
Anoka	5	NOCO Cooperative

Figure 3.24:

Cost of Fuel Cell Electric Generation		Estimated Costs for 50kW PEM Fuel Cell if Mass Produced		
Time Frame	Cost ($/kW)	Units of Production	Steam Methane Reformer, PEM Fuel Cell and Inverter/Controller	Compressor, Hydrogen
2000-2004	$3,625	1	$404,800 ($8,096/kW)	$172,864 ($3,457/kW)
2005-2009	$3,000	100	$144,054 ($2,881/kW)	$79,947 ($1,599/kW)
2010-2014	$2,425	10,000	$52,186 ($1,044/kW)	$44,281 ($886/kW)

Figure 3.25: Potential Energy and Demand Savings by 2010

	Energy Savings	Demand Savings
Electric	3,000 – 3,200 GWh	980-1,100 MW
Natural Gas	10,500,000	

Figure 3.26: Commercial and Industrial Projects Ranked according to lowest average cost for saving energy

End-use	Average $/kW	Low $/kWh	High $/kWh
Custom Grant	0.0022	0.0008	0.005
Compressed Air	0.0024	0.0021	0.0028
Lighting	0.0029	0.0021	0.0179
Refrigeration	0.0038	0.0021	0.0215
Air Conditioning	0.0057	0.0039	0.0120
Motors	0.0074	0.0064	0.0116

Figure 3.27: Commercial and Industrial Projects Ranked according to lowest average cost for saving demand (capacity)

End-use	Average $/kW	Low $/kWh	High $/kWh
Custom Grant	295	135	483
Compressed Air	322	247	478
Lighting	366	297	573
Refrigeration	369	275	1,949
Air Conditioning	386	275	545
Motors	535	291	1,434

Figure 3.28: Residential Projects

End-use	Average $/kW	Low $/kW	High $/kW
Ranked according to lowest average cost for saving demand (capacity)			
Saver's Switch	205	160	236
Central AC	764	719	828
Lighting	4,658	2,799	6,753
Ranked according to lowest average cost for saving energy ($/kWh)			
Lighting	$0.0414	$0.0225	$0.0489
Central AC	$0.0973	$0.0916	$0.1055

Figure 3.29: Costs of Saving Natural Gas

End-use	Average $/kW	Low $/kW	High $/kW
Commercial and Industrial Customers			
Boilers	$0.1597	$0.1145	$0.2492
Custom	$0.4979	$0.3320	$1.7189
Water Heating	$0.8704	$0.7643	$1.0570
Residential Customers			
Space Heating	$1.03	$0.55	$1.33
Water Heating	$1.21	$0.95	$2.34
Weatherization	$3.52	$1.73	$139.42

CHAPTER 4: ELECTRIC TRANSMISSION

Transmission of Electric Power: The Basics

Electricity, for the most part, must be delivered to consumers instantaneously as it is produced, through wires that directly connect the consumer to generating sources. Minnesota's and the nation's electric system relies primarily on large, central station generating plants as the primary source of electric energy. This electricity is carried long distances by transmission lines to substations, then by lower voltage distribution lines to individual customers. The terms "electricity," "power" and "current" are generally used interchangeably to describe flows of electricity over transmission lines. They are used interchangeably in this chapter.

The North American transmission system has been described as the largest machine ever made by humans. It is a large, intricate network of overhead power lines that are arranged in a manner similar to our highway system. The larger, high voltage transmission lines deliver bulk power to large load centers and are like the interstate highway system. Successively lower voltage lines get smaller is size, but with increasing total miles in each voltage class, to connect to every community and electricity customer in Minnesota, just as roads do.

Transmission lines in Minnesota range in size from the largest at 500kV (kV = kilovolt; a kilovolt = 1,000 volts) down to 69 kV. Lines of 69 kV, 115 kV, and 161 kV are the most common in the state, and are the links from small generators and from the larger, bulk lines to distribution substations. The larger lines, sized at 230 kV, 345 kV and 500 kV, require increasingly larger support towers and wider rights-of-way. These larger lines are often less compatible with other infrastructure that require rights-of-way and are often challenging to route and build. They can also span many miles between distribution points, connecting remote generators and utilities across several states. These long spans raise questions about how affected communities benefit if there are no local "intersections".

Utilities own and operate more than 6,500 miles of transmission line (above 115 kV in size) in Minnesota. This represents an investment of more than three-quarters of a billion dollars. New lines cost in the range of $250,000 per mile for 115 kV projects to over $1 million per mile for the higher voltages. Other equipment at substations, such as voltage transformers, can cost $20 million or more for a single transmission project. These costs are typically recovered by increases in electricity rates paid by the utility's customers.

As electricity emerges from high voltage transmission substations, it is routed into sub-transmission grids. As the electricity moves further down the system, voltages are reduced at substations along the way. The electricity then flows to various local substations and distribution transformers. The voltage then delivered through distribution lines to the customer depends on the end-user's requirements; most homes are supplied with around 240 volts, although this is used in most residential circuits at 120 volts.

Transmission lines are strung on tall structures, often 100 feet or more in the air. The lines are so high because, as more and more electricity is forced through a line, the line's temperature rises and it expands (or "sags"). Blackouts can be started by a transmission line sagging into a tree branch or other structure and shorting out. Electric current that is thereby displaced to alternate lines can cause overload or sagging on those lines as well. It is important both to plan for adequate capacity and to maintain the line's environment to avoid disruptions of power supply.

Over time, expansion and contraction cause power lines to wear out. Transmission lines face other stresses as well; wind, ice and tornadoes are common causes of outages. Even solar flares can induce large currents in grids and disrupt electric service. Transmission lines generally last 30 to 40 years with routine maintenance. With more aggressive maintenance, utilities can double that. Many lines built in Minnesota in the 1950s, however, are in need of reconditioning or replacement.

As lines are replaced because they are no longer serviceable, or as increased demand for electricity requires additional capacity, the voltage of the line is often upgraded within the existing right-of-way. Where the electric demand is creating new load centers, new lines on new rights-of-way are required. It is often possible to share rights-of-way with other linear infrastructure such as roads and highways.

The Transmission Grid

In Minnesota electric service is provided by regulated monopolies. Each utility has an exclusive geographic area in which it is the sole retail provider of electric power. The present transmission system that has evolved over time was initially designed to transmit electricity from generation plants in a utility's service area to the utility's customers in the same area. Then, utilities began to interconnect their systems, and some utilities built transmission lines to out-of-state generation sources, such as to the coal fields of North Dakota and the hydroelectric dams in Manitoba. These interconnections and interdependencies have produced interstate electric transmission systems that challenge the ability of individual states to continue to apply regulatory policies that can vary from state to state.

Acronyms for Transmission-speak

FERC – the Federal Energy Regulatory Commission

MAPP – Mid-Continent Area Power Pool
MISO – Midwestern Independent System Operator
RTO – Regional Transmission Operator
NERC – the North American Electric Reliability Council
NAERO – North American Electric Reliability Organization
EPRI – Electric Power Research Institute

Electricity actually flows throughout the transmission grid in a manner determined not by where a particular generator and customer are located but by following many different paths simultaneously, like water flowing down hill, according to the various paths of least resistance available. This "parallel path" flow pattern can cause unintended current loading on lines not directly in the path between a particular utility generator and customer, even on lines owned by a neighboring utility or on transmission lines in distant parts of the region.

The long distance interconnections between utilities were originally created to provide backup access to each other's power plants in case of trouble with one or more generating plants or transmission lines. Today, utilities engage in the purchase and sale of electricity in the open wholesale market, as a result of changes in federal law. The number and scope of long distance energy transactions has increased significantly. These many new transactions, along with the "parallel path" flow phenomenon, have caused "bottlenecks" to appear in the transmission network. The wholesale market attempts to conduct business along economically attractive transmission pathways, which often do not parallel and may even conflict with physical transmission pathways.

Each element of the transmission grid today serves a dual purpose. It carries native load transactions for its owner (utility generation plants to the utility's customers) and serves the wholesale market place as well. Depending on the size, type, and location of a particular line, the relative proportion of use of transmission elements for these two purposes will shift toward one use or the other. Generally, lower voltage transmission elements will be primarily load serving, and the larger voltage facilities will carry more regional transactions.

Underlying the electric power transaction function of the transmission system is the reliability support that any particular element contributes to the local and regional transmission system. Reliability of the transmission system has two parts:

system security; and

adequacy of supply.

The reliability characteristics of the system elements set the physical limits within which both native load and wholesale market transactions can take place.

Who is Responsible for Transmission?

The transmission system is vital to the provision of electric service to customers. The consequences of failures in the system can be significant. Economic consequences of reliability problems are not easily quantified but are significant. On a national scale, the U.S. Department of Energy (DOE) estimates that outages and other significant power fluctuation cost $30 billion per year in lost production.

There are three main categories of responsibility relating to the transmission system:

Operations,
Planning, and
Reliability.

The transmission owning utilities in Minnesota have responsibilities in all three areas. These utilities are responsible for maintaining the existing transmission grid and for building needed additional transmission as well. Other entities that have responsibility for transmission include the North American Electric Reliability Council (NERC) and the Mid-Continent Area Power Pool (MAPP).

NERC is the electric reliability organization for all of North America. It has operated since 1968 as a voluntary organization whose principal mission is to promote the reliability and adequacy of electric supply. Its members are its subregional reliability organizations. All continental states and Canadian provinces are part of one of the subregional organizations. NERC establishes standards to ensure adequate reliability of the electric grid system. It is in the process of transforming itself into a broader industry group with a more mandatory compliance approach and intends to become the North American Electric Reliability Organization, or NAERO.

Figure 4:1 NERC MAP showing MAPP

MAPP, the NERC subregional organization that includes Minnesota, is a voluntary association of electric utilities and other electric industry participants. It was formed in 1972 for the purpose of pooling generation and transmission resources. MAPP continues to transform its original mission to keep pace with industry changes. It now has 107 members including investor-owned utilities, cooperatives, municipals, public power districts, power marketers, regulatory agencies, and independent power producers. MAPP's offices and control center are in St. Paul.

MAPP presently has three main functions:

it is a reliability council, responsible for the safety and reliability of the bulk electric system, under NERC, including systemwide planning functions;

it is a regional transmission group, responsible for facilitating open access of the transmission system; and

it is a power and energy market, where MAPP members and non-members may buy and sell electricity. By the end of 2001, MAPP's operational and planning functions for most of its members will be transferred into a much larger regional transmission organization, called the Midwest Independent System Operator (MISO), which is discussed later.

Responsibility for daily operation of the transmission grid lies with each individual utility. Each transmission owning utility operates what is known as a control area. The utility balances electric supply with electric demand for that area, controls voltage and frequencies, and controls the loading on the transmission elements within the control area. The individual control areas are linked operationally in our multi state region through the MAPP facilities in St. Paul.

Utility transmission planning responsibilities for Minnesota and surrounding states have been coordinated and managed through an extensive planning process at MAPP since 1996. MAPP has the authority to order one of its member utilities to build facilities if deemed necessary for reliable grid operations. A key component of the MAPP transmission planning system is a "bottom up" process of sub regional planning groups that includes the member utilities serving five different sub sections of the MAPP region.

Individual utilities that own transmission facilities have had the primary responsibility to plan for the future expansion and maintenance of the transmission grid. Each utility considers a range of forecasts of future load growth expectations and its own selection of choices for electric supply when conducting its transmission planning. The main driving force behind this planning has been the adequacy of electricity supply for local load serving obligations. Increasingly transmission planning must take into account considerations for bulk power transactions and open access to the system for nontraditional transmission transactions.

MAPP reports that transmission adequacy for our region is not in a critical situation -- yet. The region has not seen a major upgrade, however, since the late 1970s.

Federal Policies are Having an Increasing Influence on States

The North American power grid is actually three loosely interconnected grids: one in Texas and two more (east and west), splitting the rest of the country roughly along the Continental Divide. Minnesota and other north central states encompassed by MAPP are in the eastern grid.

Figure 4.2 MAP showing 3 national grids and major transmission lines

For mostly economic reasons, federal regulators are advocating greater power transfers over longer distances. Federal policy changes have been the principle driving force behind the dramatic changes that have been occurring in the transmission system. The Federal Energy Regulatory Commission (FERC) oversees wholesale electric rates and service standards, as well as the transmission of electricity in interstate commerce. FERC ensures that wholesale and transmission rates charged by utilities are just and reasonable and not unduly discriminatory or preferential. It also reviews utility pooling and coordination agreements. Power suppliers who refuse to comply with FERC regulations are subject to penalties.

When the federal Energy Policy Act of 1992 created a class of non-utility power market participants referred to as independent power producers, FERC responded with a landmark policy order in 1996 that created an open access policy requirement for all transmission owning entities under its jurisdiction. This order requires transmission owners to provide equal access to all market participants on a “first come, first served” basis. The order also sets policies regarding operations of the grid and requires separation between the power marketing arm and transmission operating arm of vertically integrated utilities. It shifts the function of the transmission grid from primarily serving the transmission owners' interests (connecting generation with consumers) to creating a common carrier system for electricity that is open to market use, more like natural gas and other pipelines.

Responsibility for transmission infrastructure development and management of the transmission system is shifting more and more from individual utilities in loosely organized regional organizations to more structured regional transmission organizations. Federal policies continue to drive developments in this direction. In a subsequent FERC order, all transmission-owning entities were strongly encouraged to join a Regional Transmission Organization (RTO). These RTOs would have functions and characteristics that would facilitate independent system operations and stimulate development of large wholesale energy market areas. FERC further clarified its vision for transmission system management in July 2001 by stating that it wants just four large RTOs to manage the entire U.S. transmission system.

In the Midwest, most of the transmission owning members of MAPP are in the process of joining with utilities from several other regions in forming the Midwest Independent System Operator (MISO), based in Indianapolis, Indiana. MISO intends to qualify as a

FERC mandated RTO by the end of 2001. It will become the operational control entity for a large multi state region of the transmission grid.

Figure 4.3 MISO Map

FERC expects that RTOs will have operational control of the transmission system including short-term reliability responsibility. MISO will also take over the facilities planning (100kV and above) for its member utilities. As the members of MAPP transition to membership in MISO, the MAPP planning process must convert to the MISO approach, still under development. Minnesota utilities and regulators are advocating that MISO retain much of the current MAPP planning process. Some of MAPP's assets and functions will be maintained in St. Paul under the new MISO structure.

Though there are significant changes occurring in how the electric industry is organized, managed and regulated, there is broad consensus that the transmission system will continue to be federally regulated as the common carrier in the wholesale electric energy market. There is debate, however, about what role state governments will have or whether FERC will be the only regulator. There is a proposal to grant authority to FERC for approval of transmission lines that are needed regionally, and for granting eminent domain rights necessary to acquire right-of-way for construction. This would entail a large and mostly unprecedented shift of eminent domain authority from states to the federal government. The authorities related to the planning of the electric transmission system have always been assigned to individual states. An alternative proposal would require groups of states to form organizations that would have the necessary authority to manage regional planning issues.

State Review of Transmission Planning

The state’s interest in transmission facility planning has been to ensure that:

> costs to captive retail rate payers are reasonable;
>
> the energy supply for retail customers in the state is adequate and reliable; and
>
> adverse environmental effects from large energy facilities are within accepted standards.

The State of Minnesota oversees the adequacy and reliability to supply and delivery of electricity by three means.

Planning

Integrated resource planning (IRP) is required of each electric utility every two years using 5, 10 and 15 year planning horizons to determine the additional resources the utility needs to meet forecasted demand. The emphasis in resource planning is on demand-side management, such as conservation, energy efficiency and load management, and on renewable energy resources for adding new capacity to the system. A utility must first show why these resources will not meet its needs before it may propose building traditional electric infrastructure. Resource plans are approved by the Minnesota Public Utilities Commission (MPUC) after analysis by the Department of Commerce, the Office of Attorney General, and various interested parties.

Need

The second means of oversight is the Certificate of Need (CoN) process. Every large energy facility (generally a 50+ megawatt generation facility or a 100+kV transmission line with 10+ miles in the state) must receive a CoN from the MPUC. Criteria for granting a CoN again looks to whether the need could be met without constructing traditional electric infrastructure. As with resource planning, a CoN request is analyzed by the Department of Commerce, the Attorney General and others.

Environmental Review

Third, any proposed large energy facility must pass environmental review at the Minnesota Environmental Quality Board. See Chapter 5 for a discussion of recent changes to the need and environmental review statutes to streamline the regulatory processes.

The trend toward regionalization of transmission planning functions, coupled with the increasing ability of independent power producers to determine generation type and location, has had a disruptive effect on the traditional planning processes. Managing impacts to ratepayers from the costs of transmission facilities has traditionally been based on need and whether the facilities are “used and useful” to the ratepayers themselves. The evolution of the use of the transmission system for market purposes and for regional transactions has complicated the traditional analysis. As new generation plants are proposed in Minnesota for local needs and for interstate transfers, it is certain that new investment in the transmission system will be required and adequate, but not intrusive, regulatory processes must be further developed.

The state’s interest in transmission issues has evolved over time in response to policy shifts. For example, legislative mandates for wind energy (Minn. Stat. § 216B.2423) focuses attention on the need for sufficient transmission outlet capacity for wind energy resources that are most economically sited in southwest Minnesota. Substantial transmission improvements are necessary in southwestern and central Minnesota to maintain the reliability of the electrical system as wind-powered generation is developed on Buffalo Ridge. Most of the electricity generated on the Ridge must be moved on the transmission system to distant markets, primarily the Twin Cities area. With the wind turbines that are now committed on the Ridge, the transmission capacity in that area is fully utilized. Expansions are necessary for any further wind development in that area. This need raises new issues, including how to allocate the costs of new or upgraded transmission lines. In the new open access environment, the means of cost recovery and how to allocate costs between new transmission lines that serve a site-restricted generation source are not yet clear.

Transmission system requirements need to be integrated with broader state objectives for energy supply resources. Emerging technologies generally, like wind energy resources, may encounter institutional barriers to development that may require state policy initiatives if the resources are to be efficiently integrated into the infrastructure.

The wholesale market use of transmission facilities creates a need to develop new policy tools to evaluate the merchant or market need and the local load serving needs. Transmission projects that allow for increased transactions between profit seeking competitors in the wholesale market will have an impact on the average wholesale price in the market. This in turn should flow through to lower prices for retail consumers, but there is no precedent for how the state should analyze the costs and benefits of this type of project. The state must carefully assess opportunities that improve market efficiency while continuing to balance environmental and social interests.

Improved Technology

There are significant incentives to make technology improvements. Improved control components will be developed and installed to handle the increased complexity of operation of more competitive systems. Solid state controls and power conditioning equipment are likely to grow in importance. Transmission system owners will need improved telecommunications with all parts of their networks; they may also seek to provide telecommunications services using existing network infrastructure. Improved conductors, transmission line towers and underground transmission technologies could help alleviate bottlenecks and reduce the cost of new lines.

The Electric Power Research Institute (EPRI), the research and development arm of the electric industry, reports that use of real-time information generated by new monitoring technology has allowed one western U.S. utility to improve capacity on a major circuit and defer construction of a new transmission line for up to five years and savings of up to $20 million. New superconducting cable technology has the potential to carry three to ten times the current of existing underground cable systems, and with the first installation underway in Detroit, it has promise for applications in constrained right-of-way environments.

EPRI recommends that the existing radial, electromechanically controlled grid needs to be transformed into an electronically controlled, smart electricity network in order to handle the escalating demands of competitive markets in terms of scale, complexity and power quality.

Minnesota will need new approaches for comparing the costs and benefits of innovative alternatives to a transmission project, including non-transmission options. Distributed generation or emerging renewable technologies like microturbines and fuel cells also have the potential to address the reliability, load serving, and market serving functions of today's electricity delivery system. Innovative technology is rapidly creating options that will allow all classes of customers with critical needs to bypass the grid. As a result, EPRI observes, if the grid doesn't meet the growing performance challenge, its value could be steadily diminished to a provider of last resort.

As it becomes increasingly difficult and costly to develop expanded or new transmission capacity in Minnesota, it will be necessary to consider technology options among the alternatives evaluated. Technology options must be treated as a distinct component of the transmission planning process.

Managing Risk

Methods of quantifying the comparison of generation, transmission, and demand side resource alternatives need to be developed. A particularly difficult comparison challenge is the analysis of market price change risks and reliability risks between alternatives. Reliability risks fall into two general categories - system security risks and adequacy of supply risks. The pending deficit in generating capacity in MAPP projections is an example of an adequacy of supply risk. The “regional blackout scenario” that might occur at any time from a storm related disturbance is an example of a system security risk. Effective planning must identify the magnitude and probability of reliability challenges to both adequacy of supply and system security. Priorities for future infrastructure additions must be developed considering a risk management approach that is consistent with the public interest.

Minnesota must also be certain that maintenance of the transmission system meets industry standards, so that risk of outage from physical damage is kept to a minimum. Managing risk from failures of computerized operating systems and from potential sabotage require a new focus, and become increasingly critical as transmission interconnections expand on a national scale. New technologies that better manage the flow of electrons on the existing system should be applied whenever feasible, both to enhance the operation of the existing system and to reduce the need for new lines.

Minnesota's public and private utility planning processes are capable of adequately addressing transmission system needs. We must continue to work on ways to better balance public interests so that the necessary transmission system can be better configured and efficiently operated to meet growing demand.

The state regulatory agencies will continue to participate in the transmission planning process at MAPP and in discussions about how regional planning will transition to the MISO organization. It is imperative that the state's transmission owners and regulators retain reasonable control of planning and development of the transmission system that serves Minnesota electric consumers.

New Developments

As part of the new energy legislation enacted in 2001, the Legislature established a transmission planning procedure that will allow state regulators and others to gain a more comprehensive view of transmission needs and how to best meet those needs. The new statute authorizes transmission owners (utilities, for the most part), either individually or jointly, to file with the MPUC a biennial list of needed transmission projects. The MPUC will apply the criteria of the Certificate of Need statute in analyzing these projects and will issue a list of approved projects. This approval process will satisfy the requirement for an individual CoN for each project. It is likely that some larger transmission projects, such as the needed upgrade to serve southwestern Minnesota, will continue to seek separate CoNs, but that a number of smaller to mid-sized projects could be addressed collectively. Over time, this process will not only build greater efficiency into the regulatory process, but will also increasingly acquaint regulators with a comprehensive view of the transmission system and larger system infrastructure and operation needs. The first filing is due this November. Lots of effort by regulators and by utilities is going into trying to make this new approach work for everyone.

Another new development is the announcement in September 2001 of the formation of TRANSLink Transmission Co. LLC. This "independent transmission company" is being formed by Xcel Energy, Alliant Energy, MidAmerican Energy (mostly an Iowa utility), Nebraska Public Power, Omaha Public Power, and Corn Belt Power (an Iowa cooperative) to take on some of the functions that FERC envisions being performed by a Regional Transmission Operator, such as security coordination and market monitoring. These functions would otherwise be performed by the new MISO (Midwest Independent System Operator). The nonprofit MISO has a special provision in its transmission owners' agreement that allows for-profit groups like the newly proposed company to join as special members. American Transmission Co. LLC, a for-profit company that owns and operates the transmission systems of Wisconsin's major utilities, is a member of MISO in the special member category.

TRANSLink is intended to satisfy FERC requirements that electric utilities separate their transmission operations from their power supply (generation plants or power purchases) and wholesale and retail load serving functions. The company will need FERC and MPUC approval for structure, relationship with the member utilities, and new tariffs (services and prices). The Department of Commerce will actively participate in the proceedings before both bodies to ensure that the public interest of Minnesotans is represented in the creation and operation of this new company. Allocation of costs of constructing and operating the regional transmission system between ratepayers, power sources, bulk power customers, and others will entail very detailed analysis by the Department in these proceedings.

A conclusion presented in the Department's 2000 Energy Policy and Conservation Report continues to define strategic direction for infrastructure needs. It read: "The demand for energy continues to increase but the power generating facilities and transmission infrastructure used to deliver power are already being used to their maximum potential. In order to preserve stable, reliable and attractively-priced energy resources, the energy companies, government and other affected parties must work together to adjust energy planning, management, and governance to maximize energy conservation and enable emerging energy fuel sources and generation technologies to be developed and needed infrastructure enhancements to be built.[73]

[73] Energy Policy and Conservation Report for 2000, Minnesota Department of Commerce, p. 38.

Figure 4.1

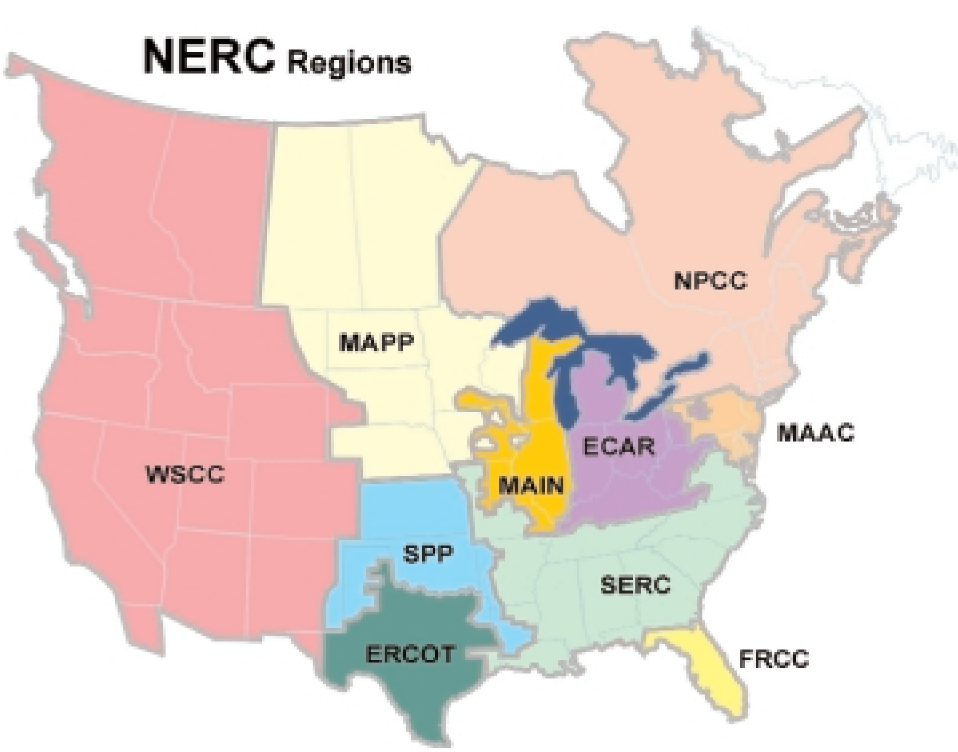
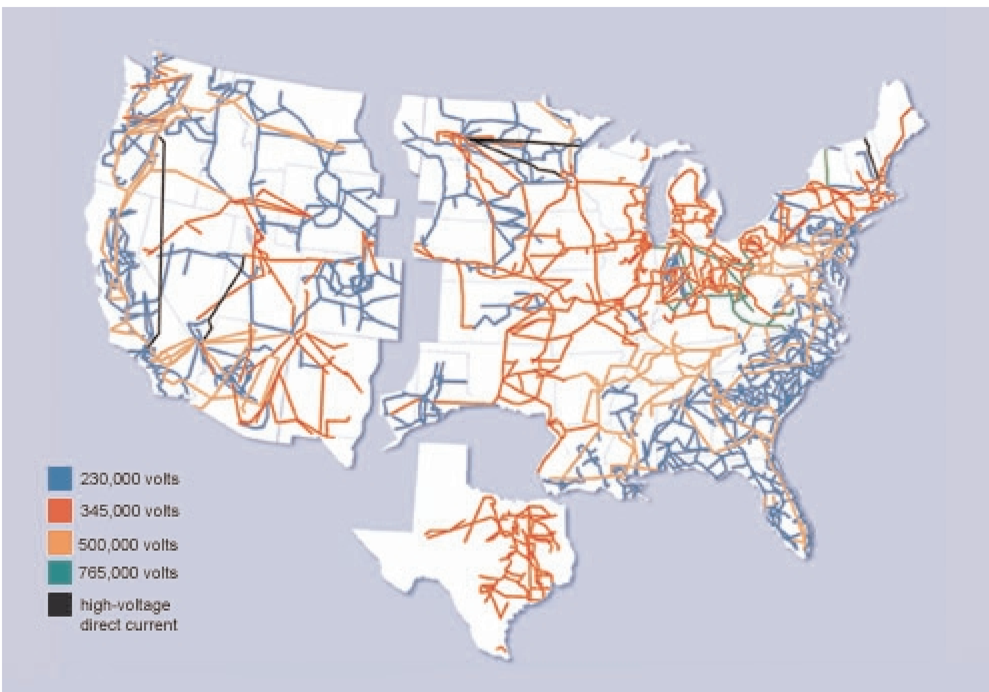


Figure 4.2



The U.S. power network is built in three large grids: the Eastern, Texas and Western systems. While connected in a handful of spots by direct-current lines, the grids largely operate independently. This map shows the major lines.

Figure 4.3


Midwest ISO
Service Territory
MANITOBA
MONTANA
NORTH DAKOTA
MINNESOTA
SOUTH DAKOTA
WISCONSIN
WYOMING
MICHIGAN
NEBRASKA
IOWA
COLORADO
ILLINOIS
INDIANA
OHIO
WEST VIRGINIA
KANSAS
MISSOURI
KENTUCKY
VIRGINIA
NORTH CAROLINA
TENNESSEE
OKLAHOMA
ARKANSAS

CHAPTER FIVE: POWER PLANT SITING AND ROUTING OF TRANSMISSION LINES

The legislature enacted the Power Plant Siting Act (PPSA) in 1973. At that time there was an expected need to build generation plants and transmission lines in the state, and awareness of the need to properly manage the effects of energy infrastructure construction on the Minnesota environment had become apparent. The purposes of the PPSA remain the same today as they were back in 1973:

> The legislature hereby declares it to be the policy of the state to locate large electric power facilities in an orderly manner compatible with environmental preservation and the efficient use of resources. In accordance with this policy, the [environmental quality] board shall choose locations that minimize adverse human and environmental impact while ensuring continuing electric power system reliability and integrity and ensuring that electric energy needs are met and fulfilled in an orderly and timely fashion.[74]

In 1973, the demand for electric energy was increasing at a rate of 7 to 8 percent per year, and had been doing so for decades. By 1973, there were approximately 5,500 megawatts of electric generation capacity located in Minnesota. If demand had continued to increase at historic rates, generation capacity would have needed to be doubled in the next ten years. In the mid-1970s, nuclear power plants were starting to fall into public disfavor. Most proposals for new power plants were for coal fired power plants. Finally, locating new generation plants outside of the state requires long distance high-voltage transmission lines, which are difficult to route.

While several transmission lines and a handful of power plants were sited under the PPSA in the 1970s, electric demand growth slowed considerably as a result of a recession, deindustrialization, and a wave of conservation efforts by electric users. By 1981 to 1983, the annual average growth of electric use in Minnesota was very low. As the economy recovered after 1983, the demand for electricity in Minnesota began to increase again but at much lower levels than in the early 1970s. This resulted in a 15 year period, between 1982 and 1997, where very little generation was sited in Minnesota compared to the 1960s and 1970s. No new transmission line over 200 kilovolts has been routed in Minnesota since 1981.[75] Figure 5-1 shows the chronology of power plants sited under the PPSA. Figure 5-2 shows the same information regarding high voltage transmission lines.

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[74] Minnesota Statutes 116C.53, subd. 1 (2000).

[75] This historical summary was derived from Hynes, Routing Transmission Lines and Siting Power Plants, Sept. 1999, available from the Environmental Quality Board.

As explained above, growth in electric demand and the need for more power in the region has created a need for more generation to be built. It has also begun to strain the capabilities of transmission lines throughout the upper Midwest region. Routing transmission lines and siting power plants under the PPSA likely will occur frequently in this decade.

In 2001, the legislature made the most significant changes to the PPSA since its enactment 28 years ago. The changes were designed to clarify and streamline the siting of power plants and routing of transmission lines, while preserving effective public participation in the issues relevant to these decisions. To attain this objective, the legislature made several changes.

First, the legislature, as much as possible, aligned the thresholds for the certificate of need process before the Public Utilities Commission (PUC) with the thresholds for routing or siting by the Environmental Quality Board (EQB). Although there have been few transmission line proposals in recent years, two very controversial proposals concerned the Arrowhead transmission line in Duluth and the proposed Chisago transmission line. In both cases, the decision required more review time than provided by law, and involved controversy over the need for the project. Neither required a certificate of need from the PUC.

Despite the long time between the Chisago and Arrowhead transmission routing proceedings and the proceedings in the 1970s, they bogged down in the same way.[76] When the PUC had not made a determination of need, the decision on where to route a transmission line became extremely controversial in front of the EQB. The controversy focused on whether the transmission line was needed at all instead of where to locate it. In the history of the PPSA, the proceedings that did not bog down were those where the PUC determined a need or where need was completely apparent.

As a result of the changes, more transmission line proposals will be presented to the PUC for a determination of need. In the Certificate of Need proceeding, the participatory rights of the public were not changed. There will be a larger number of transmission line proposals before the PUC because the changes require state approval of smaller transmission lines than in the past. This places the need determination in the best forum. It should allow the routing process to focus exclusively on locating the transmission line in the most appropriate way possible considering environmental and land use issues.

The second major change in the PPSA is the elimination of the exemption process in favor of a shorter, alternative review process for smaller power plants and transmission

[76] See Electric Power Facility Siting and Routing Projects, 1973-1981, Environmental Quality Board.

lines. Prior to 2001, certain power plants and transmission lines would be presented to the EQB for a determination as to whether the project should be sited under the PPSA or was exempt from state siting. An exemption approval resulted in sending the project to local authorities for a proceeding to decide the route site. It was, in essence, a whole proceeding to determine the next proceeding.

The 2001 changes establish an alternative review process for smaller proposals whereby the applicant or an affected local unit of government can decide to present the proposal to the EQB for decision. If that is the case, the EQB will decide the matter within six months. Whether the EQB or a local government makes the decision, there is only one proceeding that results in a final decision.

Other changes create tighter standards that should result in proceedings being completed on time, rather than being extended multiple times. An example is the elimination of the so-called "process to decide a process" problems in the PPSA. The statute categorizes projects by size, establishes the level of environmental review and public procedure that will apply, and sets forth a clear timeline for decision. This should prevent timelines being extended because of state or local government jurisdictional disputes, or contentions that further levels of environmental review should be required. Finally, siting and routing decisions should be more timely because, in almost every case, a definitive determination of need will have been made by the PUC.

The legislature accomplished these improvements to the PPSA while maintaining the same public participation procedures that have applied throughout the history of the PPSA. The only difference in public participation is that members of the public who wish to participate in the need determination must do so before the PUC because that issue will not be decided by the EQB. The certificate of need process before the PUC has always been an open public process.

Finally, utilities may now propose multiple transmission projects at one time, and have them certified as to need or not certified as to need by the PUC in the same proceeding. This procedure hopefully will allow citizens a greater understanding of the inter-relationship of the transmission needs of different utilities and how proposals for new or upgraded lines fit into longer term transmission planning. November 1 of this year is the deadline by which utilities must file the projects for which they seek approval. It will be important to monitor this proceeding to determine whether the greater statewide context in which individual transmission line proposals will be discussed will help everyone gain a better understanding of the interrelationships and need for new transmission. It is also important to determine if this joint process results in greater efficiencies. This type of proceeding has not been attempted elsewhere, and the initial proceeding should be watched carefully to determine whether it is attaining its objectives.

These are significant changes. Very shortly the effectiveness of these changes will be tested by both power plant and transmission line proposals. Further changes should not be made to the PPSA until the 2001 changes can be implemented and the proceedings evaluated. The exception to this is there should be a determination of whether the criteria for the certificate of need for merchant plants and bulk power transmission lines need to be changed. The Department of Commerce initially supported exemption of merchant plants from the certificate of need statute. We became concerned about this position, however, when it became apparent that without a need determination the EQB locational proceeding becomes bogged down in questions of need that citizens feel have not been properly dealt with in a public forum. As a result, these facilities should be subjected to some appropriate review as to need. The criteria for the certificate of need, however, may not apply as well to merchant plants and bulk power transmission lines as they do to utility owned facilities dedicated to serve local customers. The statutes assume that power plants and transmission lines would only be built by vertically integrated utility monopolies subject to pervasive regulatory oversight by the PUC. Since merchant plants are not plants that propose to include their capital costs in the base rates of utility consumers, the current criteria in the certificate of need statute may need some revision to properly evaluate proposed merchant plants. Additionally, with the federal changes to the bulk power transmission market, the certificate of need criteria for these transmission facilities should be reviewed for possible change. We request public comment on this issue.

Figure 5.1: Power Plants Sited Under the PPSA, 1973-2001

Sherburne County 3	800MW	Coal	1975
Clay Boswell 4	500MW	Coal	1976
Cottage Grove Cogeneration	245MW	Gas	1994
Lakefield Junction	550MW	Gas	1999
Pleasant Valley	434MW	Gas	2000

Figure 5.2: Transmission Lines Routed Under the PPSA, 1973-2001

Warroad to Little Fork	230KV	105 miles	MP	1974
N. Dakota to Coon Rapids	400KV	172 miles	CU	1976
	345KV	28 miles		
Kettle River to Chisago	500KV	80 miles	MP	1976
Chisago to Grant	345KV	35 miles		
Forbes to Manitoba	500KV	200 miles	Xcel	1977
Kettle River to Forbes	500KV	60 miles	MP	1977
Boswell to Blackberry	230KV	19 miles	MP	1979
Benton to Milaca	230KV	25 miles	UPA	1980
Sherco to Benton	345KV	17 miles	Xcel	1981
Pleasant Valley to Nearest Line	345KV	<1 mile	GRE	2000