# Alternative Evaluation Study

Prepared for

**Dairyland Power Cooperative**

Prepared by

CH2MHILL

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# Contents

## Tables



## Figures

# Acronyms and Abbreviations

| | |
|---|---|
| AES | Alternative Evaluation Study |
| BACT | Best Available Control Technology |
| Btu | British Thermal Units |
| CFB | Circulating Fluidized Bed |
| $CH_4$ | Methane |
| C&I | Commercial and Industrial Generators |
| CO | Carbon Monoxide |
| $CO_2$ | Carbon Dioxide |
| CTGs | Combustion Turbine Generators |
| DOE | U.S. Department of Energy |
| Dairyland | Dairyland Power Cooperative |
| EERE | U.S. DOE Energy Efficiency and Renewable Energy |
| EIA | U.S. DOE Energy Information Administration |
| EIS | Environmental Impact Statement |
| EPA | U.S. Environmental Protection Agency |
| ESP | Electrostatic Precipitator |
| °F | degrees Fahrenheit |
| FERC | Federal Energy Regulatory Commission |
| FGD | Flue Gas Desulfurization |
| GHGs | Greenhouse Gases |
| HAPs | Hazardous air pollutants |
| Hg | Mercury |
| HRSG | Heat Recovery Steam Generator |
| $H_2S$ | Hydrogen Sulfide |
| IGCC | Integrated Gasification Combined Cycle |
| INEEL | U.S. DOE Idaho National Engineering and Environmental Laboratory |
| IR | Ingersol Rand |
| JPM | John P. Madgett Station |
| kW | Kilowatts |

| | |
|---|---|
| KWh | Kilowatt Hours |
| lb | Pound |
| LFG | Landfill Biogas |
| LMOP | Landfill Methane Outreach Program |
| MACT | Maximum Achievable Control Technology |
| MAIN | Mid-American Interconnected Network |
| MAPP | Mid-Continent Area Power Pool |
| MSW | Municipal Solid Waste |
| MW | Megawatts |
| MWh | Megawatt Hours |
| NEMS | National Energy Modeling System |
| NEPA | National Environmental Policy Act |
| NGCC | Natural Gas Combined Cycle |
| $NH_3$ | Ammonia |
| $NO_x$ | Nitrogen Oxides |
| NPHR | Net Plant Heat Rate |
| PC | Pulverized Coal |
| $PM_{10}$ | Particulate Matter |
| Ppm | Parts Per Million |
| PRB | Powder River Basin |
| PSD | Prevention of Significant Deterioration |
| PV | Photovoltaic |
| RDF/yr | Refuse-Derived Fuel Per Year |
| REC | Rural Electric Cooperative |
| REPI | Renewable Energy Production Incentive |
| RUS | Rural Utility Service |
| SCF | Standard Cubic Foot |
| SCR | Selective Catalytic Reduction |
| $SO_2$ | Sulfur Dioxide |
| SNR | Selective Non-Catalytic Reduction |
| SPCC | Spill Prevention Control And Countermeasures |
| STG | Steam Turbine Generator |

| | |
|---|---|
| URGE | Uniform Rating of Generating Equipment |
| Wh/m²/day | Watt-Hours Per Square Meter Per Day |
| WWTP | Wastewater Treatment Plant |

# 1.0 Introduction

This report presents the results of the Alternative Evaluation Study (AES) study conducted as part of the overall Dairyland Power Cooperative (Dairyland) siting study. The AES followed the requirements established in the Rural Utility Service (RUS) Bulletin 1794A-603 *Scoping Guide for RUS Funded Projects Requiring Environmental Assessments with Scoping and Environmental Impact Statements*, February 2002. The AES identified supply alternatives that could be considered in lieu of the proposed technology, including a "no build" option. The evaluation of the "no build" option included energy conservation and efficiency and was based partly on load information provided by Dairyland. Options for the purchase of capacity and energy are currently under consideration by Dairyland through a competitive bidding process and through negotiations with neighboring utilities.

The AES addresses the need for the project and provides an analysis of alternative methods that have been considered to meet that need. The alternatives studied are presented below, with the AES addressing the cost-effectiveness, technical feasibility, and environmental soundness of each alternative considered. The AES addressed each of these issues for the alternatives listed below:

1. **Energy conservation and efficiency** - Demand side management and the ability of increased energy efficiency to offset the projected increase in energy demand will be considered.
2. **Noncombustible renewable energy resources** - Technologies to be considered will include wind, solar voltaic, hydroelectric and geothermal.
3. **Combustible renewable energy sources** - Technologies to be considered will include biomass, biogas, landfill gas, and municipal solid waste.
4. **Nonrenewable combustible energy resources** - Technologies to be considered will include (in the order listed):
   - (i) natural gas-fired boilers and combustion turbines in simple and combined cycle configurations
   - (ii) oil and coal with a sulfur content of less than 1 percent
   - (iii) other carbon-based fuels including fluid-bed combustion and integrated gasification combined cycle (IGCC) technology.

Cost-effectiveness was addressed by evaluating both the initial capital costs involved with the various energy options as well as the long-term operation and maintenance costs, including fuel costs over the projected life of the project. Cost estimates were developed based on CH2M HILL's existing knowledge and general industry information.

Technical feasibility was evaluated based on the proven ability of the various energy alternatives to provide a highly reliable source of generation compatible with the project needs as defined in the statement of Purpose and Need (see following section). The ability of the various energy options, such as solar and wind, to meet the operational requirements established for the proposed project was an important factor in evaluating the technical feasibility of the various alternatives under consideration. The environmental compatibility of the various energy options was evaluated based on information regarding engineering and operational considerations, regulatory and environmental opportunities, and constraints (e.g., air emissions, water use and discharge, land area required, and general permitability).

# 1.1 Purpose and Need

With headquarters in La Crosse, Wisconsin, Dairyland provides wholesale electricity to 25 member distribution cooperatives and 20 municipal utilities. Dairyland's service area encompasses 62 counties in 5 states (Wisconsin, Minnesota, Iowa, Illinois, and Michigan). Dairyland has provided low-cost, reliable electrical energy and related services to its customers in the upper Midwest for over 61 years.

Dairyland's electric system load is derived (through its member distribution cooperatives) from two main categories of customers: residential, which includes both urban and farm customers; and commercial and industrial, which range from small retail to heavy industrial customers. There are also several minor contributors to system load, including irrigation, street and highway lighting, and public authorities (such as schools and town halls) and resale to eight small municipal utilities.

# 1.2 Electric Load

The future numbers of these customers and the amount of electricity each one uses define the future load. Load growth within each of these categories and overall load forecasts are discussed below.

## 1.2.1 Residential

Residential loads account for around 77 percent of retail electricity sales by Dairyland's member cooperatives. The number of residential customers has been increasing at an annual rate of 1.6 percent over the last 10 years, with most of this growth coming from residential subdivisions being developed around the larger cities in Dairyland's service territory. The number of farm customers has declined over the last decade, primarily due to the consolidation of farmland into larger individual farms.

Dairyland projections indicate an increase in numbers of residential customers of 1.7 percent annually over the next 20 years as the expansion of urban areas continues.

The amount of electricity used per residential customer is expected to decline at an average annual rate of 0.2 percent over the next 20 years. Factors influencing individual residential customer use of electricity are the following:

- Lower electricity use for household heating, due to more efficient heating appliances and increased use of natural gas heating
- Increased use of air conditioning

- Lower electricity use for water heating due to more efficient water heaters and increased use of natural gas for water heating
- More efficient refrigerators and freezers
- More efficient lighting
- Increased electricity use per farm because of larger farm size and increased mechanization

Dairyland's forecasts indicate that the decrease in energy use per residential customer will not be enough to offset the increase in the number of customers. Total electricity sales to residential customers are expected to increase 1.4 percent per year over the next 20 years.

### 1.2.2 Commercial and Industrial

Dairyland divides its commercial and industrial customers into small and large commercial and industrial customers. Small commercial and industrial customers include restaurants, retail stores, and small manufacturing facilities. Large commercial and industrial customers are mostly larger manufacturing facilities, such as ethanol plants. The number of small commercial and industrial customers is expected to increase by 1.8 percent per year over the next 20 years in line with growth in the regional economy.

Dramatic increases in small commercial and industrial electricity use per customer (4.1 percent per year over the last 5 years) are expected to level out to a rate of 0.8 percent per year over the next 20 years. This is due to a more conservative economic forecast and the natural upper limits to facility sizes.

The increase in small commercial and industrial customers is anticipated to result in total electricity use by this sector to increase by 2.6 percent per year over the next 20 years. This increase will be driven mainly by the increasing number of customers in this category.

Efforts by local governments to encourage industrial development and strong regional economic growth have resulted in large increases in load from the large commercial and industrial sector. This is anticipated to continue with a projection of 4.6 percent growth per year in sales to this sector.

### 1.2.3 Other Classes

An increase of 1.4 percent annually is expected in electricity use for irrigation, street lighting, and public authorities over the next 20 years. This sector of use accounts for about 5 percent of retail sales by Dairyland's member cooperatives.

## 1.3 Generation

### 1.3.1 Generating-Capacity Mix

The most economical means of supplying the cyclical load on an electric power system is to have three basic types of generating capacity available:

a. Baseload capacity
b. Intermediate load range capacity
c. Peaking capacity

Baseload capacity runs near its full rating continuously, day and night, all year long. It is economical to design these units with a maximum of fuel-economizing features, highest practical steam temperatures and pressures, extensive use of regenerative boiler-feed water heaters, reheat and double-reheat boiler-turbine arrangements, and large condensers with minimum-temperature cooling water. These items increase the cost of the plant but are justifiable because the fuel-cost saving is large due to the large amount of power produced by having the unit run continuously.

The design of the plant is optimized to obtain the balance between high first cost and low fuel cost that will give the lowest overall power cost under the assumption that the unit will be heavily loaded for many years. The best design will vary depending on the unit size, money costs, and fuel type and cost.

Peaking capacity is run only during daily peak-load periods during the seasonal peak times of the year and during emergencies. Because the total annual output is low, high efficiency is not as necessary as for baseload units. Very low first cost is important. Combustion turbines and pumped-stage hydro units are the typical peaking units.

Intermediate load range capacity fits between the baseload capacity and peaking capacity in both first cost and fuel cost. It generally is designed to be "cycled", that is, turned off regularly at night or on weekends and loaded up and down rapidly during the time it is on the line to take the load swings on the system. Some additional cost is required to allow for repeated starts and stops without equipment damage or the need for larger operating staffs. However, owing to the lower annual production, some reduction in efficiency is justified.

Older small baseload units and hydro units with restrictions on water use are sometimes used for intermediate and peaking service.

### 1.3.2 Dairyland Power Cooperative Generating Facilities

During the summers of 1996, 1997, 1998, and 1999, Dairyland experienced record demand for electrical service. While Dairyland was able to meet that peak demand, it did so with a margin of only 1.4 megawatts (MW) of excess capacity in July 1999. The entire Mid Continent Area Power Pool (MAPP) was precariously close to going capacity deficit on several occasions in July 1999. Additionally the transmission grid was severely constrained and subjected to "line loading relief" curtailments. These events have caused the MAPP reliability council to change to seasonal vs. annual Uniform Rating of Generating Equipment (URGE ) ratings to more carefully monitor MAPP members' ability to serve their loads. This change in URGE rating requirements resulted in an ~30 MW derate of Dairyland's summer generating capability.

Dairyland has been able to manage a portion of their capacity requirements by purchasing energy and capacity from other MAPP utilities. However, the near-term lack of excess capacity in MAPP and increasing transmission constraints have combined to severely diminish the future viability of purchasing capacity from other utilities. MAPP, of which Dairyland is a member, has a projected deficit of generation by the early 2000s. Transmission constraints and line loading relief events continue to interrupt delivery among many MAPP and Mid-American Interconnected Network (MAIN ) utilities. Therefore, long-term purchase of transmission, capacity, and energy from MAPP and/or MAIN members is not a viable option.

Dairyland and its member cooperatives have already implemented load management in conjunction with incentive pricing and energy conservation programs. Various load management programs are used to control approximately 150 MW of interruptible peak demand with approximately 82,500 radio receivers controlling water heaters, space heaters, water and heat pumps, fans, air conditioners and standby generators. This represents approximately 20 percent of the Dairyland load.

The Elk Mound Combustion Turbines near Elk Mound, Wisconsin, were added to the Dairyland system in 2001 to address peak capacity needs. Dairyland's two Elk Mound Combustion Turbines add 71 MW of reliable peaking capacity to the Dairyland system and the upper Midwest. The turbines are used during peak periods—those times when consumers place the greatest demand on Dairyland's generating system. Additionally, the units are equipped with a "black start" system, which will allow the units to start with no external power supply or load signals. This feature enhances reliability, as it would allow Dairyland to bring back its entire system in the event of a widespread blackout. Dairyland has budgeted in 2004 for software upgrades to the Elk Mound Combustion Turbines' controls to increase the capacity rating of each unit by about 2 MW.

Dairyland's Alma Station located near Alma, Wisconsin, consists of five coal-fired generation units. The first two units, Alma #1 and #2, were constructed in 1947. Alma #3 was built in 1950 and Alma #4 in 1957. The largest and final unit, Alma #5, came on-line in 1960. Today, Alma Units #1 through 3 generate a total of 584 MW, Alma #4 generates 57 MW, and Alma #5 has a generating capacity of 77.3 MW. The Alma Station burns coal that travels by barge from southern Illinois and by rail and barge from Wyoming via transfer docks situated along the Mississippi River.

The John P. Madgett Station (JPM) is adjacent to the Alma Station. This generating station has been in commercial operation since November 1979. The single unit station has a generating capacity of 366 MW. JPM burns about 1 million tons of low sulfur western coal from mines in the Powder River Basin area of Wyoming each year. The coal is received by 2 unit railroad trains of 115 cars each. Dairyland has budgeted in 2004 for upgrades to the John P. Madgett Station that will increase the units' output by approximately 26 MW.

Genoa-3, located near Genoa, Wisconsin, burns coal received by barge from southern Illinois and by rail to barge from Wyoming in the Powder River Basin. The different coals are blended onsite for economics and environmental compliance. Cooperative Power, Eden Prairie, Minnesota, has a life-of-the-plant agreement with Dairyland to receive about 170 MW from the 349 MW output of Genoa-3. This leaves Dairyland with 179 MW.

The Flambeau Hydroelectric Station, 22 MW, located on the Flambeau River near Ladysmith, Wisconsin, was built in 1951. The federal operating license expired in 2001 and the facility is operating under the terms of the expired license until a new license is issued. Dairyland expects a new 30 year license to be issued in 2004.

Dairyland has additional peaking capacity available under contract with the municipals that it serves. These municipals, including Arcadia, Argyle, Cashton, Cumberland, Elroy, Fennimore, La Farge, Merrillan, New Lisbon, and Viola in Wisconsin; Lanesboro in Minnesota; and Forest City in Iowa, contribute 77 MW of capacity.

Table 1-1 shows the capacity factors achieved in recent years by Dairyland's generating plants. Table 1-2 shows typical designations of generating plants according to capacity factor.

TABLE 1-1
Capacity Factors of Dairyland Generating Plants

| | 1998 | 1999 | 2000 | 2001 | 2002 | Average |
|---|---|---|---|---|---|---|
| Elk Mound – 1 | | | | 3% | 1% | 2% |
| Elk Mound – 2 | | | | 3% | 1% | 2% |
| Alma – 1 | 29% | 25% | 32% | 29% | 28% | 29% |
| Alma – 2 | 32% | 27% | 28% | 30% | 30% | 29% |
| Alma – 3 | 30% | 22% | 27% | 38% | 28% | 29% |
| Alma – 4 | 55% | 45% | 59% | 35% | 59% | 51% |
| Alma – 5 | 51% | 38% | 55% | 49% | 49% | 48% |
| Flambeau | 26% | 34% | 34% | 41% | 53% | 38% |
| Genoa – 3 | 52% | 63% | 71% | 69% | 77% | 66% |
| J.P. Madgett | 68% | 72% | 75% | 79% | 72% | 73% |

TABLE 1-2
Capacity Factors by Plant Designation

| Designation | First Cost | Fuel Cost | Typical Annual Capacity Factor % |
|---|---|---|---|
| Baseload capacity | High | Low | 65 – 75 |
| Intermediate-load-range Capacity | Intermediate | Intermediate | 30 – 40 |
| Peaking Capacity | Low | High | 5 – 15 |

Based on the table of capacity factors by Plant Designation and MAPP summer seasonal URGE ratings, Dairyland's generating facilities would be classified as the following:

a. Baseload capacity (545 MW)
   1. Genoa-3 179 (349 - 170 to Cooperative Power)
   2. J.P. Madgett 366

b. Intermediate-load-range capacity (214.7 MW)
   1. Alma – 1 19.8
   2. Alma – 2 20.2
   3. Alma – 3 18.4
   4. Alma – 4 57.0
   5. Alma – 5 77.3
   6. Flambeau 22.0

c. Peaking capacity (147.8 MW)

| | |
|---|---|
| 1. Elk Mound – 1 | 35.2 |
| 2. Elk Mound – 2 | 35.6 |
| 3. Municipals | 77.0 |
| **Total Generation Capacity** | **907.5** |

# 1.4 Load and Generating Capability

## 1.4.1 Growth in Generation to Serve Baseload

The present baseload generators of the Dairyland system are Genoa-3 and J.P. Madgett. The combined capability of these two generators is 545 MW. Both generators are presently operating as near to full annual output as is practical, considering their high annual capacity factors, the required weeks of downtime for preventative maintenance, and their increasing forced outage rates.

a. Both units' annual capacity factors are high, in the 65 to 75 percent range for Genoa-3 and in the 70 to 80 percent range for J.P. Madgett.

b. The Forced Outage Rate for both units has begun to rise steadily, indicating a high level of stress on the equipment when operating at the present generating levels.

Dairyland's annual growth in total system peak load for the period 1997-2003 has averaged 2.1 percent. Dairyland has projected load growth to continue in the 2.0 percent to 3.0 percent range through 2008 and then to level off at approximately 1.8 percent through 2019.

It is projected that there will be a deficit in generation capacity of approximately 205 MW by 2010 and 244 MW by 2012 (Figure 1-1 and Table 1-3).

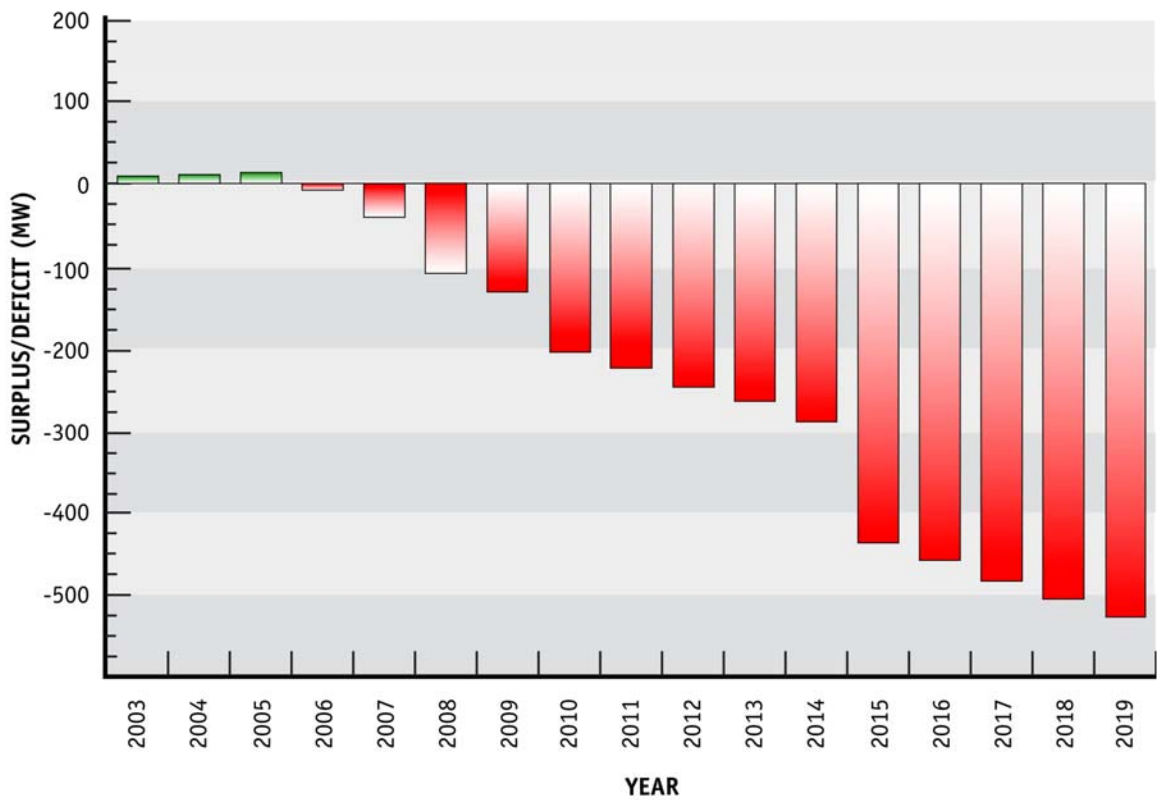



FIGURE 1-1
Dairyland Generation Surplus/Deficit Projections

Dairyland's baseload energy generators represent approximately 60 percent of the existing system capacity. The MAPP peak demand on Dairyland's system in 2003 was 813 MW. The system total firm capacity obligation is projected to be approximately 1,277 MW in 2019 (10 years after the proposed power plant is in-service).

TABLE 1-3
Dairyland Generation and Load Projections

| | Summer | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1A | Seasonal maximum demand | 797 | 813 | 842 | 859 | 876 | 894 | 911 | 927 | 944 |
| 1B | Demand at time of seasonal system demand | 797 | 813 | 842 | 859 | 876 | 894 | 911 | 927 | 944 |
| 2 | Schedule L purchases at time of SSP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Seasonal System Demand (1B - 2) | 797 | 813 | 842 | 859 | 876 | 894 | 911 | 927 | 944 |
| 4 | Annual system demand | 797 | 813 | 842 | 859 | 876 | 894 | 911 | 927 | 944 |
| 5 | Firm purchases - total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | Firm sales - total | 0 | 0 | 0 | 0 | 0 | 4 | 4 | 4 | 4 |
| 7 | Seasonal adjusted net demand (3 - 5 + 6) | 797 | 813 | 842 | 859 | 876 | 898 | 915 | 931 | 948 |
| 8 | Annual adjusted net demand (4 - 5 + 6) | 797 | 813 | 842 | 859 | 876 | 898 | 915 | 931 | 948 |

TABLE 1-3
Dairyland Generation and Load Projections

| | Summer | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|---|---|
| 9 | Net generating capability | 1071 | 1077 | 1088 | 1114 | 1114 | 1114 | 1114 | 1114 | 1055 |
| 10 | Participation purchases - total | 116 | 67 | 61 | 56 | 56 | 50 | 0 | 0 | 0 |
| 11 | Participation sales - total | 255 | 201 | 170 | 170 | 170 | 170 | 170 | 170 | 170 |
| 12 | Adjusted net capability (9 + 10 - 11) | 932 | 944 | 979 | 1000 | 1000 | 994 | 944 | 944 | 886 |
| 13 | Net reserve capacity obligation (8*15%) | 120 | 122 | 126 | 129 | 131 | 135 | 137 | 140 | 142 |
| 14 | Total firm capacity obligation (7 + 13) | 916 | 935 | 968 | 987 | 1008 | 1033 | 1052 | 1071 | 1090 |
| **15** | **Surplus or deficit capacity (12 - 14)** | **16** | **9** | **11** | **13** | **(7)** | **(39)** | **(108)** | **(127)** | **(205)** |

| | Summer | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|
| 1A | Seasonal maximum demand | 961 | 978 | 996 | 1014 | 1032 | 1050 | 1069 | 1087 | 1107 |
| 1B | Demand at time of seasonal system demand | 961 | 978 | 996 | 1014 | 1032 | 1050 | 1069 | 1087 | 1107 |
| 2 | Schedule L purchases at time of SSP | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Seasonal System Demand (1B - 2) | 961 | 978 | 996 | 1014 | 1032 | 1050 | 1069 | 1087 | 1107 |
| 4 | Annual system demand | 961 | 978 | 996 | 1014 | 1032 | 1050 | 1069 | 1087 | 1107 |
| 5 | Firm purchases - total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | Firm sales - total | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| 7 | Seasonal adjusted net demand (3 - 5 + 6) | 965 | 982 | 1000 | 1018 | 1036 | 1054 | 1073 | 1091 | 1111 |
| 8 | Annual adjusted net demand (4 - 5 + 6) | 965 | 982 | 1000 | 1018 | 1036 | 1054 | 1073 | 1091 | 1111 |
| 9 | Net generating capability | 1055 | 1055 | 1055 | 1055 | 921 | 921 | 921 | 921 | 921 |
| 10 | Participation purchases - total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | Participation sales - total | 170 | 170 | 170 | 170 | 170 | 170 | 170 | 170 | 170 |
| 12 | Adjusted net capability (9 + 10 - 11) | 886 | 886 | 886 | 886 | 751 | 751 | 751 | 751 | 751 |
| 13 | Net reserve capacity obligation (8*15%) | 145 | 147 | 150 | 153 | 155 | 158 | 161 | 164 | 167 |
| 14 | Total firm capacity obligation (7 + 13) | 1110 | 1130 | 1150 | 1171 | 1192 | 1212 | 1234 | 1255 | 1277 |
| **15** | **Surplus or deficit capacity (12 - 14)** | **(224)** | **(244)** | **(264)** | **(285)** | **(440)** | **(461)** | **(482)** | **(504)** | **(526)** |

Table 1-4 shows Dairyland's historical load and energy requirements. System peak capacity requirements increased on average by 16.1 MW annually from 1997 to 2002. Allowing for the 15 percent reserve requirement shows that Dairyland's average energy generation requirement is increasing by 14 MW annually. System energy requirements have been increasing on average by 91,618 megawatt hours (MWh) annually from 1997 through 2002. The average increase in system energy requirements requires a 75 percent capacity factor from the average increase in capacity. This indicates that Dairyland is adding load at a baseload rate.

TABLE 1-4
Dairyland Historical Load and Energy Requirements

| | Peak MW | Class A MWh | Class D MWh | Losses MWh | Total MWh |
|---|---|---|---|---|---|
| 1997 | 716.0 | 3,381,718 | 459,592 | 198,347 | 4,039,658 |
| 1998 | 728.8 | 3,384,066 | 413,572 | 196,092 | 3,993,730 |
| 1999 | 762.9 | 3,464,304 | 414,219 | 200,269 | 4,078,792 |
| 2000 | 757.0 | 3,583,166 | 425,736 | 207,001 | 4,215,903 |
| 2001 | 792.5 | 3,654,377 | 428,586 | 210,825 | 4,293,788 |
| 2002 | 796.4 | 3,825,771 | 451,140 | 220,840 | 4,497,750 |
| **Avg. Increase** | **16.1** | | | **Avg. Increase** | **91,618** |

# 1.5 Conclusion

The addition of 250 MW to 300 MW of baseload capacity in 2009 will allow Dairyland to meet capacity and energy requirements in that time frame and allow for additional growth in following years. The addition of 400 MW of baseload capacity in 2009 will allow Dairyland to work with a partnering utility to achieve greater economies of scale to reduce generation costs.

# 2.0 Energy Alternatives Evaluated

The specific energy alternatives addressed in this analysis include the following:

- Energy conservation and efficiency
- Noncombustible renewable energy resources
- Combustible renewable energy sources
- Nonrenewable combustible energy resources

## 2.1 Energy Conservation and Efficiency

### 2.1.1 Overview

Energy efficiency means doing the same work—or more—with less energy. Energy efficiency improvements can free up existing energy supply, so energy efficiency can be considered part of a state's energy resources.

Dairyland has implemented both an aggressive system of load control as well as a program of incentives for its customers to install energy efficient appliances. The load control system operated by Dairyland is a FM radio one-way system, which became operational in December 1982. Sixty-eight transmitter sites are used to cover the approximate 44,000-square -mile service territory. Over 100,000 loads are currently controlled by the installed radio receivers.

Dairyland currently controls approximately:

- 75,000 Residential electric water heaters
- 16,000 Residential dual fuel heating systems
- 5,000 Residential air conditioners
- 5,000 Residential heat storage systems
- 215 Commercial and industrial generators (C&I)
- 50 Peak Alert voluntary load reduction (C&I)
- 110 Agricultural grain dryers
- 6 C&I bulk interruptible under direct control

#### Approximate Winter Load Control

| | |
|---|---|
| • Residential electric water heaters | 40 MW |
| • Residential dual fuel heating systems | 20 |
| • Residential air conditioners | 0 |
| • Residential heat storage systems | 35 (off peak daily control) |
| • C&I generators | 20 |
| • Peak Alert voluntary load reduction (C&I) | 20 |
| • Agricultural grain dryers | 5 |
| • C&I bulk interruptible under direct control | 10 |
| **Total Winter Load Controlled Under Peak Conditions** | **150 MW** |

## Approximate Summer Load Control

| | |
|---|---|
| • Residential electric water heaters | 30 MW |
| • Residential dual fuel heating systems | 0 |
| • Residential air conditioners | 3 |
| • Residential heat storage systems | 5 (off peak daily control) |
| • C&I generators | 20 |
| • Peak Alert voluntary load reduction (C&I) | 5 |
| • Agricultural grain dryers | 3 |
| • C&I bulk interruptible under direct control | 10 |
| **Total Summer Load Controlled Under Peak Conditions** | **76 MW** |

The various member cooperatives actively promote the load control program for residential and commercial customers with energy discounts available. Dairyland's load control program is successful in saving approximately $4,111,000 worth of energy on an annual basis.

Other programs available for reducing loads and increasing energy efficiencies are primarily focused on purchasing energy efficient electric water heaters, use of dual-fueled space heating, communications on the benefits of switching to propane gas, and use of weatherization.

Dairyland has operated an established program of incentives for its customers to install energy-efficient appliances including lighting systems, central air conditioners, and electric water heaters. The purpose of this program is to promote the use of energy-efficient appliances and thus reduce load growth.

A brief summary of the currently available incentives is provided below.

**Water Heater Program** – The purpose of this program is to increase water heater market share through promotion of controlled electric water heaters. Electric water heater installations, sized 80 gallons or larger, and using Dairyland's load management system with a minimum 6-hour control are eligible. The program offers matching dollars for Rural Electric Cooperative (REC) incentives on controlled water heating systems (water heaters, storage water heaters, hot tubs, and dairy water heaters).

**Energy-Efficient Retrofit Lighting Program** – The purpose of the retrofit lighting program is to encourage energy efficiency and provide value to Dairyland's customers. The program is offered through the cooperative members. Three types of energy-efficient lighting systems qualify for incentives. These are electronically ballasted fluorescent fixtures, metal halide fixtures, and sodium vapor fixtures. Fixtures must be hard-wired to qualify, with Dairyland providing up to $10.00 per fixture .

**Efficient Central Air Conditioner Program** – The purpose of this program is to reduce summer peak conditions at a cost that is lower than the estimated market value of summer capacity and/or the cost of providing load management equipment to control air conditioning loads. The program offers incentives for energy efficient air conditioners, air source heat pumps, and earth-coupled heat pumps. Dairyland provides an economic incentive on a per ton basis ranging from $40 to $60 per ton depending on the type of unit installed.

### 2.1.2 Commercial Availability

All energy efficiency options described are readily available to Dairyland customers.

### 2.1.3 Technical Feasibility

All energy efficiency options described are proven technologies.

### 2.1.4 Cost-Effectiveness

The cost-effectiveness of energy efficiency and incentive programs can be quite variable and highly dependent on the effectiveness of the program approach. Dairyland has implemented an aggressive program of load control, which results in a savings of $4,111,000 worth of energy on an annual basis. Other energy efficiency incentive programs have been found to be cost-effective in terms of reducing load growth.

### 2.1.5 Environmental Compatibility

Promotion and use of energy efficient programs generally have neutral or beneficial effects on the environment by slowing down the need for additional fossil fueled power sources. Air pollutants are lessened, water quality is not affected, equipment is almost universally replacement in kind or on the end user's actual premises so footprints issues are benign. Permits that may be required are usually handled at the local level through the typical residential or commercial/industrial building permit process.

### 2.1.6 Dairyland Power Cooperative

Dairyland has implemented an aggressive load control program. It is estimated that additional load control may be able to be increased approximately 2 percent per year, yielding a reduction in load of 10 to 15 MW by the year 2009. Through its member cooperatives, the Dairyland system also offers energy efficiency and rebate programs. The programs range from rebates for energy efficient appliances to energy audits to help customers reduce energy consumption.

### 2.1.7 Capable of Fulfilling Purpose and Need

Energy efficiency programs are capable of lessening the impact of electrical demand and reducing the capacity of future additional generation facilities. However, the ability to eliminate the need for additional generation capacity within the Dairyland service area by 2009 is unlikely. While more energy efficiency programs can be put in place, these programs should be considered as paralleled activities to securing additional generation to meet the projected demand within the Dairyland service area.

# 2.2 Renewable Non-Combustible Energy Resources

The renewable non-combustible energy resources evaluated in this section are wind, hydroelectric, solar (photovoltaic [PV] and thermal), and geothermal. The electric power cost projections for these energy technologies are shown in Table 2-1 below.

## 2.2.1 Wind

### Overview

The greatest advantage of wind power is its potential for large-scale, though intermittent, electricity generation without emissions of any kind. In addition, over the years, wind energy's production cost has benefited from improvements in technology and increased reliability.

The development of wind power is increasing in many regions of the United States, including Wisconsin. Installed wind electric generating capacity expanded by nearly 10 percent during 2002 in the United States to 4,685 MW. Wind energy installations across the United States are expected to reach 6,000 MW by the end of 2003 (Ref. 10). Technological advances have improved the performance of wind turbines and driven down their cost. In locations where the wind blows steadily, wind power has been shown to compete favorably with coal and natural gas fired power plants based on receiving the federal Renewable Energy Production Incentive (REPI).

TABLE 2-1
Electric Power Cost Projections for Renewable Non-Combustible Energy Resources
*Levelized Costs for New Utility Generating Plants in Mid-Continent Area Power Pool (MAPP) Region*

| | Levelized Costs ($/MWh) | | | | |
|---|---|---|---|---|---|
| | | Solar | | | |
| **Cost Component** | **Wind** | **Photovoltaic** | **Thermal** | **Hydroelectric** | **Geothermal** [1] |
| Capital | 39.3 | 151.9 | 146.7 | 17.0 | N/A |
| Fixed O&M | 8.0 | 4.7 | 21.0 | 2.6 | N/A |
| Variable/Fuel | 0.0 | 0.0 | 0.0 | 4.0 | N/A |
| Total Busbar Cost[2] | 47.3 | 156.6 | 167.7 | 23.6 | 50-80 |

Source for Wind and Solar Costs: U.S. Department of Energy (DOE) Energy Information Administration (EIA) Annual Energy 2003 Outlook Reference Case. Based on the National Energy Modeling System (NEMS).

Source for Hydroelectric Costs: U.S. DOE Idaho National Engineering and Environmental Laboratory (INEEL) Hydropower Program website: (http://hydropower.inel.gov/facts/costs-graphs.htm).

Source for Geothermal Costs: U.S. DOE Energy Efficiency and Renewable Energy (EERE) State Energy Information – Geothermal Technology website: (http://www.eere.energy.gov/state_energy/technology_overview.cfm?techid=5).

Notes:

[1] Commercial geothermal resources not available in the Dairyland Power Cooperative (Dairyland) service area.

[2] Busbar Cost – wholesale cost to generate power at the plant.

$/MWh dollars per megawatt hour

O&M operations and maintenance

The outlook for wind energy remains favorable because of the technology's economic competitiveness, growing demand for electricity, and effective renewable energy policies adopted in several markets.

Wind turbines are mounted on a tower to capture the most energy. At 100 feet (30 meters) or more aboveground, they can take advantage of the faster and less turbulent wind. Turbines catch the wind's energy with their propeller-like blades. Usually, two or three blades are mounted on a shaft to form a rotor.

A blade acts much like an airplane wing. When the wind blows, a pocket of low-pressure air forms on the downwind side of the blade. The low-pressure air pocket then pulls the blade toward it, causing the rotor to turn. This is called lift. The force of the lift is actually much stronger than the wind's force against the front side of the blade, which is called drag. The combination of lift and drag causes the rotor to spin like a propeller, and the turning shaft spins a generator to make electricity.

There are four main parts to a wind turbine: the base, tower, nacelle, and blades. The blades capture the wind's energy, spinning a generator in the nacelle. The tower contains the electrical conduits, supports the nacelle, and provides access to the nacelle for maintenance. The base, made of concrete and steel, supports the whole structure.

Wind turbines can be used in off-grid applications, or they can be connected to a utility power grid. For utility-scale sources of wind energy, a large number of turbines are usually built close together to form a wind farm. These turbines each require about a quarter-acre of land, which includes land for the turbine and any access roads. As a result, turbines fit well onto agricultural land without taking the land out of production, simply making way for the turbine's base. All of the land in between the turbines is available for agricultural activities.

### Commercially Available

Wind power is available commercially. Installed wind electric generating capacity expanded by nearly 10 percent in the United States during 2002 to 4,685 MW. Wind energy installations across the United States are expected to reach 6,000 MW by the end of 2003. Dairyland currently has 8 MW of wind-generated power and plans for an addition 9 MW.

### Technical Feasibility

Wind resources can be used with both large wind turbines for utility applications and with small wind turbines for onsite generation. As a renewable resource, wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from class 1 (the lowest) to class 7 (the highest). In general, wind power class 4 or higher can be useful for generating wind power with large (utility-scale) turbines, and small turbines can be used at any wind speed. Class 4 and above are considered good resources.

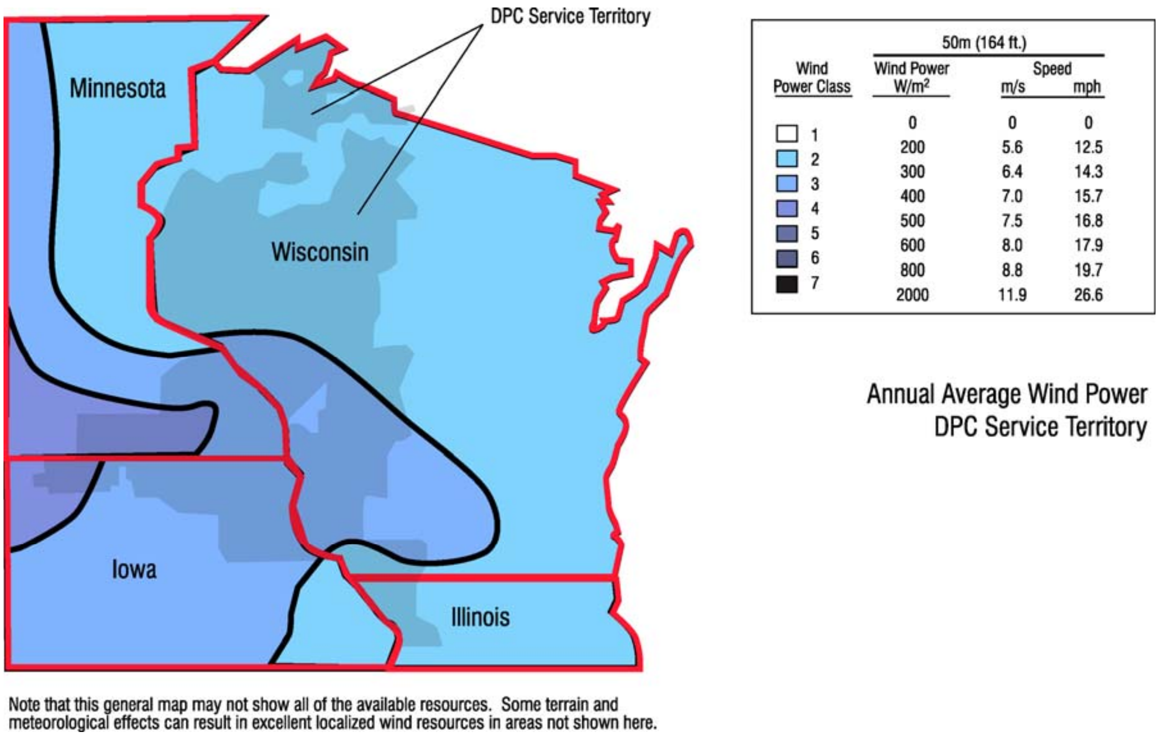
This map of Dairyland's service territory (**Figure 2-1**) shows general wind power classes for the area and indicates that Dairyland's territory has good wind resources in three areas: the southwest portion of Wisconsin, the southeast portion of Minnesota, and the northeast portion of Iowa.

Areas of the land that have a wind power class of 4 or higher are present within the overall Dairyland service territory. This Dairyland service area has the potential to support large-scale wind farm facilities with an estimate annual capacity factor of approximately 30 percent. Therefore, it is technically feasible to develop wind farms within the general Dairyland service area.

### Cost-Effectiveness

Fixed, investment-related costs are the largest component of wind-based electricity costs. Improved designs with greater capacity per turbine have reduced investment costs to approximately $750 to 1,000/kW. Wind power plants incur no fuel costs, however, and their maintenance costs have also declined with improved designs. The U.S. Department of Energy (DOE) Energy Information Administration (EIA) projects the levelized cost (the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments; costs are levelized in real dollars, i.e., adjusted to remove the impact of inflation) of wind power to be approximately $47.3/MWh (see Table 2-1).

Due to the intermittent nature of wind, a wind power plant's economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of a wind turbine's productivity. Estimates of capacity factors range from 26 percent to 36 percent.




Source: U.S. DOE EERE State Energy Alternatives website (Ref. 1).

FIGURE 2-1
Annual Average Wind Power in the Dairyland Service Territory

Another major issue regarding wind intermittence is that wind power can offer energy, but not on-demand capacity. Even at the best sites, there are times when the wind does not blow sufficiently and no electricity is generated. Related to intermittence is wind's unpredictable nature. Weather forecasting has improved markedly over the past several decades, so wind power plant operators can predict, to some extent, what their output will be by the hour. But that ability is imperfect at best. Therefore, wind power cannot always be reliably dispatched at the time it is needed.

Good wind resource areas with accessibility to nearby transmission lines do exist, however, it is more common that wind resources are located some distance from adequate transmission lines. Larger wind developments (several hundred megawatts) are more likely to be able to justify investments in transmission.

### Environmental Compatibility

While wind power has no air emissions or water use, it does have other impacts on the environment. These are visual obstruction, bird kills, and noise pollution. Mitigation measures are frequently taken to resolve these problems.

#### *Air*

There are no major direct air emissions related to the installation of a wind farm. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/natural gas emergency generators.

#### *Water*

There would be no major water discharge issues. A stormwater construction permit and management plan would likely be required for construction activities.

#### *Footprint*

A 300 MW wind farm would require approximately 86 square miles (55,000 acres) of area based on an average power output of 3.47 MW/square mile for wind power class 4 resources. As discussed previously, most of the land would be available for other uses such as agricultural production.

#### *General Permitability*

The primary obstacle in permitting large wind farms would be land issues, aesthetics, and public acceptance. Bird strikes can be a significant issue in areas of high avian use, such as major flyways. In general, environmental issues can typically be addressed to allow the development of a properly sited large-scale wind farm.

### Dairyland Power Cooperative

Dairyland currently owns one-third of the energy output from a 2 MW windfarm near Chandler, Minnesota, which is owned and operated by Great River Energy. This purchase started in 1999 and produces approximately 2,200 megawatt hours (MWh) for Dairyland annually. Dairyland uses the output from this wind farm to meet its needs in the Evergreen program. The Evergreen program offers cooperative members the ability to purchase blocks of renewable energy.

In late October 2003, Dairyland signed a power purchase agreement with G. McNeilus Wind Energy to purchase the energy output from five 1.5 MW wind turbines. The wind farm began producing energy on November 1, 2003. This wind farm is located near Adams, Minnesota, and feeds into a Dairyland 69 kV transmission line. This power purchase agreement is expected to provide 23,000 MWh annually.

The general recommendation for installed wind capacity on a utility system is 3 percent of load. Wind capacity above the 3 percent level can cause stability problems on the utility system resulting in the need for additional system infrastructure, such as static var compensators, capacitor banks or backup generation. For Dairyland, the 3 percent level would represent a practical limit of approximately 15 MW of installed wind capacity. Dairyland is currently evaluating options to bring total installed wind capacity up to that level.

### Capable of Fulfilling Purpose and Need

Wind power cannot fulfill the need for 300 MW of highly reliable baseload capacity. Wind power production is intermittent with an average annual capacity factor of 25 to 35 percent, depending on location.

The list of Wisconsin Qualified Wind Facilities (Table 2-2) indicates that wind farm projects are not viewed as large, baseload projects.

TABLE 2-2
Wisconsin Qualified Wind Facilities

| Facility No. | Electric Facility | Technology | Installed MW |
|---|---|---|---|
| | **Wind Facilities** | | |
| 105 | Badger Windpower LLC | Wind | 30.00 |
| 106 | Champepadan | Wind | 1.98 |
| 107 | Chandler Wind Farm* | Wind | 1.98 |
| 108 | Glenmore Turbines | Wind | 1.20 |
| 109 | Lincoln Turbines | Wind | 9.24 |
| 110 | Moulton Wind Project | Wind | 1.98 |
| 111 | Northern Iowa Windpower | Wind | 80.10 |
| 112 | Rosiere Wind Farm | Wind | 11.22 |
| 113 | Worthington Wind Turbines | Wind | 1.80 |
| | | **Total** | **139.50** |

Source: https://www.wirrc.com/rrc/PublicFacilityReport#Wind

## 2.2.2 Solar

### Overview

The sun is a direct source of energy. Using renewable energy technologies can convert that solar energy into electricity. However, solar energy varies by location and by the time of year. Solar resources are expressed in watt-hours per square meter per day ($Wh/m^2/day$). This is roughly a measure of how much energy falls on a square yard over the course of an average day.

Collectors that focus the sun (like a magnifying glass) can reach high temperatures and efficiencies. These are called solar concentrators. Typically, these collectors are on a tracker, so they always face the sun directly. Because these collectors focus the sun’s rays, they only use the direct rays coming straight from the sun.

Other solar collectors consist of simply flat panels that can be mounted on a roof or on the ground. Called flat-plate collectors, these are typically fixed in a tilted position correlated to the latitude of the location. This allows the collector to best capture the sun. These collectors can use both the direct rays from the sun and reflected light that comes through a cloud or off the ground. Because they use all available sunlight, flat-plate collectors are the best choice for many northern states.

Solar resources are greatest in the middle of the day — the same time that utility customers have the highest demand, especially during the summer months.

### Commercially Available

Solar concentrators and flat-plate collector types are both used in each of the solar-based technologies — PV and solar thermal.

The largest usage of PV has been in the off-grid market, which takes advantage of PV's ability to be a complete stand-alone electrical system. Telecommunications and transportation construction signage are the two largest segments of the off-grid market. Most of the off-grid market is due to remote locations and inaccessibility to the utility grid of applications, such as water pumping and highway lighting. However, in many instances, the grid may be near a well-developed area, but it is still more cost-effective to install a modular PV system, rather than to cross roadways or sidewalks.

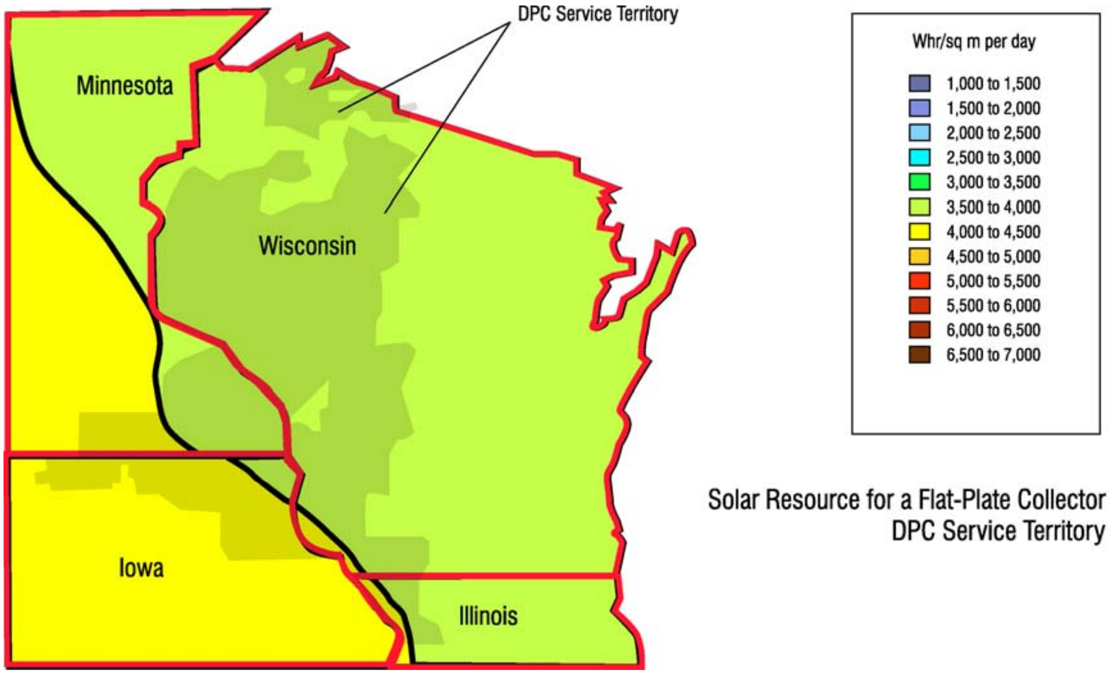
In the southwestern United States, solar thermal power is being considered primarily as an important technology resource. California, Nevada, Arizona, and New Mexico are each exploring policies that would further the development of their solar-based industries.

### Technical Feasibility

#### *Flat-Plate Collector*

Flat-plate solar systems are flat panels that collect sunlight and convert it to either electricity or heat. These technologies include PV a flat-plate collector that is installed in a tilted position, for example, on a roof. A general rule of thumb is that a flat-plate collector gets the most sun if it is tilted toward the south at an angle equal to the latitude of the location.

As this map for flat-plate collectors shows **(Figure 2-2**), Wisconsin has a useful resource throughout the state. Because of their simplicity, flat-plate collectors are often used for residential and commercial building applications. They can also be used in large arrays for utility applications.



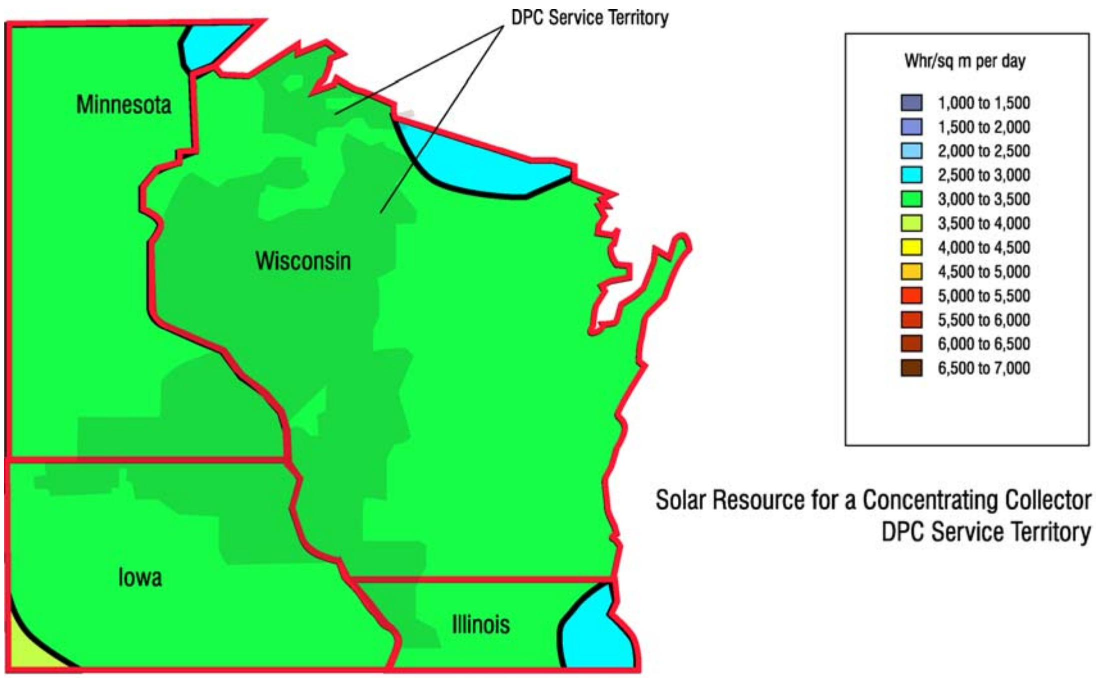

Source: U.S. DOE EERE State Energy Alternatives website (Ref. 1)

FIGURE 2-2
Solar Resources for a Flat-Plate Collector in the Dairyland Service Territory

## Solar Concentrator

Solar concentrators are typically mounted on tracking systems in order to face the sun continuously. This allows these collectors to capture the maximum amount of direct solar rays. The solar resource for concentrators varies much more across the United States than the flat-plate solar resource. Most northern states cannot use solar concentrators effectively, but this resource is even greater than the flat-plate resource in some areas of the southwestern United States.

The map (**Figure 2-3**) shows that, for concentrating collectors, Wisconsin has a marginal resource. Although certain technologies may work in specific applications, most concentrating collectors are not effective with this resource. Because these systems require tracking mechanisms, solar concentrators are generally used for large-scale applications such as utility or industrial use. But they can also be used in small-scale applications, including remote power applications.




Source: U.S. DOE EERE State Energy Alternatives website (Ref. 1)

FIGURE 2-3
Solar Resources for a Concentrating Collector in the Dairyland Service Territory

## Cost-Effectiveness

Fixed, investment-related charges are the largest component of solar-based electricity costs. The DOE Energy Information Administration projects the capital cost component of the levelized cost of solar power to be approximately $152/MWh for PV and $147/MWh for thermal solar in 2009. Solar power units incur no fuel costs. Maintenance costs are low for PV systems, however, maintenance costs are high for thermal solar applications. The total levelized cost of solar power is projected to be approximately $157/MWh for PV solar and $168/MWh for thermal solar (see Table 2-1).

Due to the intermittent nature of solar power, economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of solar power productivity. Estimates of capacity factors range from 20 percent to 35 percent.

Another major issue regarding solar power intermittence is that solar power can offer energy, but not on-demand capacity. Related to intermittence is solar power's unpredictable nature due to weather.

## Environmental Compatibility

In general, solar resources have relatively less impact on the environment as compared to other generation technologies, with the possible exceptions of aesthetics and the large area required for the facilities.

#### *Air*
There are no major direct air emissions related to the installation of a solar facility. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/natural gas emergency generators.

#### *Water*
There would be no major water discharge issues. A stormwater construction permit and management plan may be required for construction activities.

#### *Footprint*
A 300 MW PV solar farm in the best area of Wisconsin for solar power would require approximately 4,200 acres.

#### *General Permitability*
The primary obstacles in permitting a large solar installation would be land issues, aesthetics, and the public communication process. The use of other resources and emission would likely not be major permitability issues.

### Dairyland Power Cooperative

Dairyland is not currently pursuing any solar energy projects. These projects are not seen as being commercially viable within the Dairyland system.

### Capable of Fulfilling Purpose and Need

Solar power cannot fulfill the need for 300 MW of highly reliable baseload capacity within the Dairyland service area. Wisconsin has a marginal solar resource, and solar power production in the Dairyland service area would be intermittent with an average annual capacity factor of 20 to 35 percent.

The list of Wisconsin Qualified Solar Facilities (Table 2-3) indicates that solar facilities are not viewed as large, baseload projects in the Dairyland service territory.

TABLE 2-3
Wisconsin Qualified Solar Facilities

| Facility No. | Electric Facility | Technology | Installed MW |
|---|---|---|---|
| | **Solar Facilities** | | |
| 101 | Dane County Arena | Solar | 0.005 |
| 102 | Religious Society of Friends | Solar | 0.004 |
| 103 | The Heritage Center | Solar | 0.001 |
| 104 | University of Wisconsin | Solar | 0.009 |
| | | **Total** | **0.019** |

Source: https://www.wirrc.com/rrc/PublicFacilityReport#Solar

## 2.2.3 Hydroelectric

### Overview

Flowing water creates energy that can be captured and turned into electricity. This is called hydroelectric power or hydropower.

The most common type of hydroelectric power plant uses a dam on a river to store water in a reservoir or a run of the river approach, which does not result in the construction of a large reservoir. Water released from the reservoir flows through a turbine, which in turn activates a generator to produce electricity. Another form of hydroelectric power does not necessarily require a large dam but instead uses a small canal to channel the river water through a turbine.

Another type of hydroelectric power plant, referred to as a pumped storage plant, has the capacity to store energy. The power is sent from a power grid into the electric generators. The generators then turn the turbines backward, which causes the turbines to pump water from a river or lower reservoir to an upper reservoir, where the energy is stored. To use the energy, the water is released from the upper reservoir back down into the river or lower reservoir. This turns the turbines forward, activating the generators to produce electricity.

### Commercially Available

Hydroelectric power is available commercially and is responsible for a significant portion of the generation capacity in various regions of the United States and abroad.

### Technical Feasibility

The amount of hydropower resource varies widely among states. To have a useable hydropower resource, there must be both a large volume of flowing water and a change in elevation.

Wisconsin, Minnesota, Iowa, and Illinois have relatively low hydropower resources as a percentage of each state's electricity generation. Wisconsin could produce an estimated 2,417,900 MWh of electricity annually from hydropower (see **Figure 2-4** below). This would be equivalent to approximately 832 MW of installed capacity assuming a 33 percent average annual capacity factor.

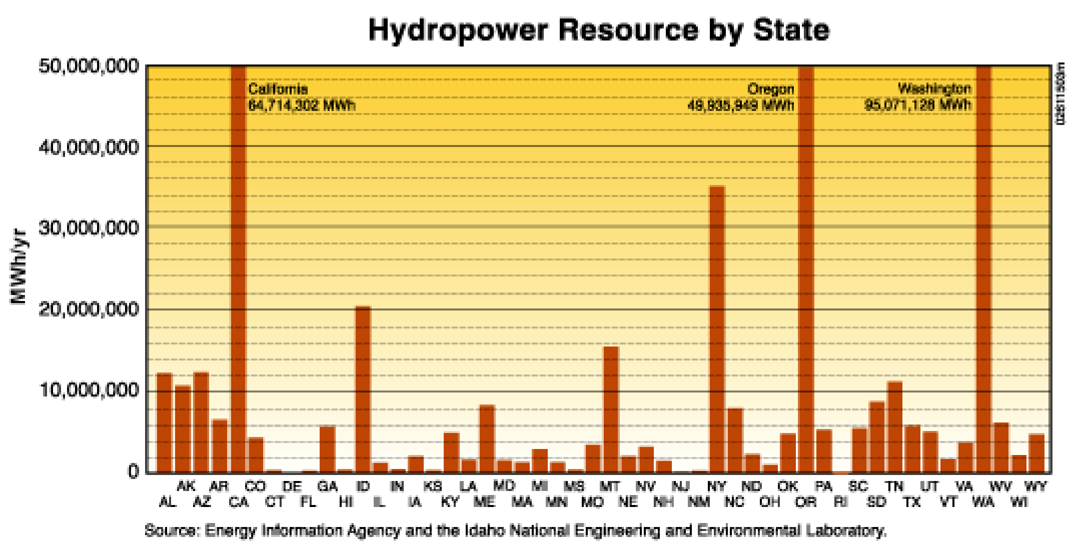



FIGURE 2-4
Hydropower Resource by State

The chart above (**Figure 2-4**) shows the overall likely potential hydropower resource by state. This includes both current hydropower generation as well as an estimate of potential additional resources. This estimate factored in the many legal, social, and environmental constraints on hydropower development.

### Cost-Effectiveness

Fixed, investment-related charges are the largest component of hydroelectric power plant costs. The DOE's Idaho National Engineering and Environmental Laboratory (INEEL) reports hydropower capital costs to be $1,700 to $2,300/kW. Operating and maintenance costs are low for hydropower. The total levelized cost of hydropower is projected to be approximately $24/MWh (see Table 2-1).

Due to the seasonal nature of hydropower, the average annual capacity factor for most facilities is approximately 30 to 40 percent. Another major issue regarding hydropower is its year-to-year unpredictable nature due to annual rainfall variability.

### Environmental Compatibility

Environmental impacts would vary dependent on the type and number of hydroelectric projects proposed: run of river, reservoir storage, or pumped storage. There would be minimal impacts in terms of air emissions, wastewater discharges, or solid waste/hazardous waste generation. The major impacts would be to the aquatic environment, alteration of river flows, land use alternations, and construction of reservoirs and structures.

#### *Air*

There are no major direct air emissions related to the installation of hydroelectric resources. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/natural gas emergency generators.

#### *Water*

While there would be no major water discharge issues compared with typical thermal power plants, the construction of an impoundment or reservoir could have various adverse impacts on water quality, wetlands, flooding of uplands, and aquatic biota. A stormwater construction permit and management plan would be required for construction activities and ongoing operation. A Spill Prevention Control and Countermeasures (SPCC) plan may be required depending on the quantity of lubricating oils, transformer oils, and fuels onsite.

#### *Footprint*

Because of the lack of significant topographic relief in southwestern Wisconsin, hydroelectric resources capable of providing 300 MW of generation would require numerous small hydroelectric facilities in the Wisconsin area.

#### *General Permitability*

The permitting of a new hydroelectric facility is typically a complex and time-consuming process requiring multiple federal and state permits and approvals. Hydroelectric facilities are regulated by the Federal Energy Regulatory Commission (FERC). In addition to the development and approval of a number of detailed resource reports, approval under the National Environmental Policy Act (NEPA) through the preparation of an Environmental Impact Statement (EIS) would likely be required. Other federal permits such as a Section 404 dredge and fill permit and Section 10 water quality certification would also be required. Various state permits through the Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin would also be required. Development of hydroelectric facility can experience significant public and agency opposition.

#### Dairyland Power Cooperative

Dairyland currently has 22 MW of hydropower generation capacity at the Flambeau Hydro Station. Flambeau Unit #3 was rewound in 2001 resulting in a capacity increase of 1.2 MW. Flambeau Unit #1 is scheduled to be rewound in February 2004 which will add an additional 1.2 MW of capacity. Due to the significant environmental issues associated with the development of new hydroelectric generation and limited resource availability, Dairyland does not have current plans to increase its hydroelectric generation capacity.

#### Capable of Fulfilling Purpose and Need

Given the limited resources available for development of hydropower in Wisconsin, it is unlikely that this technology could fulfill the need for 300 MW of highly reliable baseload capacity. Hydroelectric power production is seasonal with an average annual capacity factor of 30 to 40 percent, depending on year-to-year rainfall levels.

### 2.2.4 Geothermal

#### Overview

Geothermal energy is contained in underground reservoirs of steam, hot water, and hot dry rocks. Electric generating facilities utilize hot water or steam extracted from geothermal reservoirs in the Earth's crust to drive steam turbine generators to produce electricity. Moderate-to-low temperature geothermal resources are used for direct-use applications such as district and space heating. Lower temperature, shallow ground, geothermal resources are used by geothermal heat pumps to heat and cool buildings. Dairyland currently provides incentives to install geothermal heat pumps. Hence, the only geothermal resources that may be considered to generate power are the high temperature sources.

#### Commercially Available

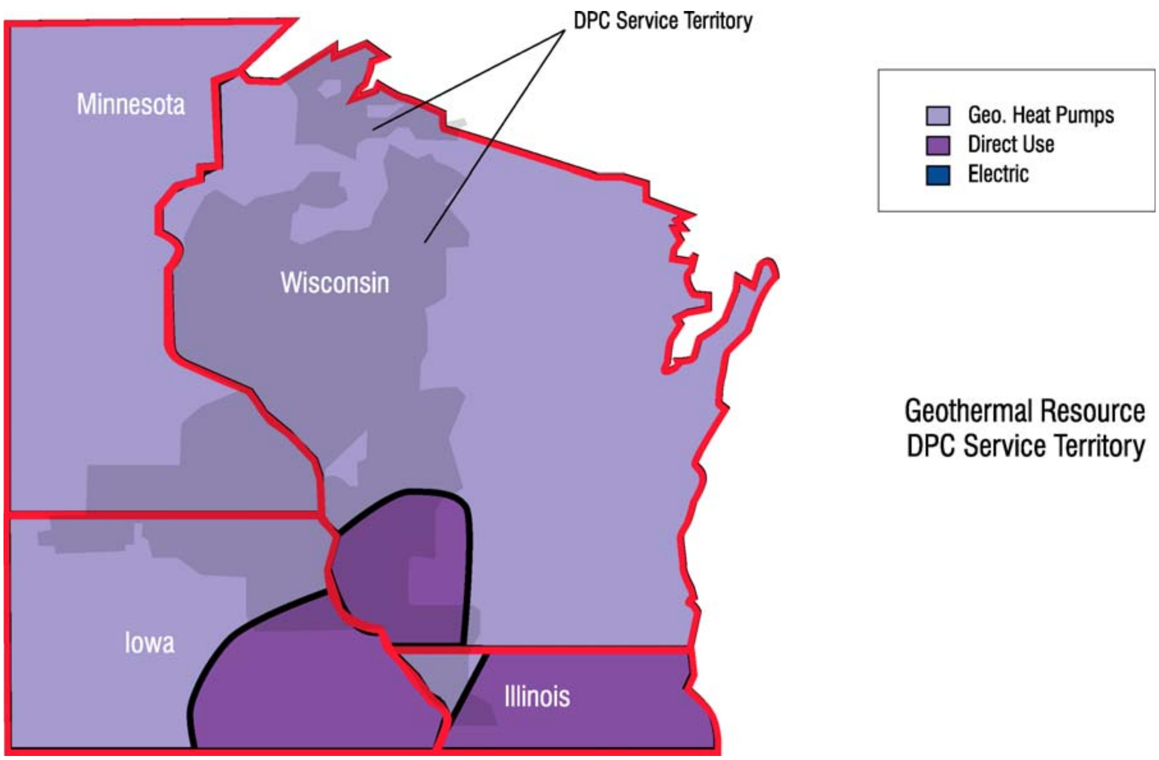
Producing electricity from geothermal resources involves a mature technology. The time from which a site is confirmed as having sufficient water or steam at temperatures high enough to drive turbines using either a binary or flash system) to the time a facility can produce electricity is typically less than 3 years. However, due to the remote locations of many geothermal resources, the cost of transmission may make the venture more expensive than a facility that is closer to an identified injection point.

About 8,000 MW of geothermal electricity are currently produced around the world, including about 2,200 MW of capacity in the United States. All of the geothermal power in the United States is generated in California, Nevada, Utah, and Hawaii, with California accounting for over 90 percent of installed capacity. A considerable amount of the power (1,137 MW) is generated at The Geysers in northern California. The Geysers is a fairly unusual (and ideal) resource because its wells produce virtually pure steam with no water.

### Technical Feasibility

Two types of geothermal resources are being tapped commercially: hydrothermal fluid resources and Earth energy. Hydrothermal fluid resources (reservoirs of steam or very hot water) are well suited for electricity generation. Earth energy, the heat contained in soil and rocks at shallow depths, is excellent for direct use and geothermal heat pumps but not as a source of electric power generation.

As indicated on the map (**Figure 2-5**), the Wisconsin has low to moderate temperature resources that could be tapped for direct heat or for geothermal heat pumps. However, electric generation is not possible with these resources. Therefore, geothermal electric power generation is not technically feasible in this area.




Source: U.S. DOE EERE State Energy Alternatives website (Ref. 1)

FIGURE 2-5
Geothermal Resources in the Dairyland Service Territory

### Cost-Effectiveness

Geothermal electric power typically ranges from $50 to $80/MWh, and technology improvements are lowering that range steadily.

### Environmental Compatibility

Geothermal energy is generally one of the cleaner forms of energy available for commercial applications. Small direct heat resources generally have minimal air and water emissions. Large geothermal resources used for electrical generation have had issues with air emissions (primarily hydrogen sulfide [$H_2S$]) and water discharges and would need additional controls to minimize emissions. The high flow rates of steam and water from geothermal wells can result in the precipitation of various compounds, primarily silica. Land disposal of precipitates would be required.

#### *Air*

The primary air pollutants of concern with geothermal resources are $H_2S$, ammonia ($NH_3$), and methane ($CH_4$). New designs are able to minimize emissions within the process and with the use of add-on control equipment. Other minor sources of emissions include particulates from the process cooling tower and those associated with support equipment such as diesel/natural gas emergency generators.

#### *Water*

Depending on the quality of the water used in the geothermal process, there may be a need for an industrial wastewater treatment permit and pre-treatment would be required. Stormwater and SPCC plans may be required.

#### *Footprint*

Land use for geothermal resources is normally small compared to fossil energy resources. A 20 MW geothermal power plant would require approximately 3 acres. Therefore, 15 of these plants having a total output of 300 MW would require a total area of approximately 45 acres.

#### *General Permitability*

Based on a good process design, there is a high probability that the necessary environmental permits and approvals could be obtained in a reasonable time.

### Dairyland Power Cooperative

Dairyland does not view geothermal generating facilities as technically or financially viable within its system.

### Capable of Fulfilling Purpose and Need

Geothermal electric power cannot fulfill the need for 300 MW of highly reliable baseload capacity within the Dairyland service area because commercial geothermal resources for the generation of electric power are not available.

## 2.3 Renewable Combustible Energy Resources

The renewable combustible energy resources evaluated in this section are biomass, biogas, and municipal solid waste (MSW). The electric power cost projections for these energy technologies are shown in Table 2-4.

TABLE 2-4
Electric Power Cost Projections for Renewable Combustible Energy Resources
*Levelized Costs for New Utility Generating Plants in MAPP Region*

| | Levelized Costs ($/MWh) | | |
|---|---|---|---|
| **Cost Component** | **Biomass** | **Biogas** | **Municipal Solid Waste (MSW)** |
| Capital | 30.0 | 37.0 | 32.8 |
| Fixed O&M | 45.0 | 6.6 | 38.9 |
| Variable/Fuel | 15.0 | 3.0 | 13.0 |
| Total | 90.0 | 46.5 | 84.8 |

<u>Source for Biomass Costs</u>: U.S. Department of Energy (DOE) Energy Efficiency and Renewable Energy (EERE) State Energy Information – Biomass Power Technology website: (http://www.eere.energy.gov/state_energy/technology_overview.cfm?techid=3)

<u>Source for Biogas Costs</u>: U.S. DOE Energy Information Administration (EIA) Annual Energy 2003 Outlook Reference Case. Based on the National Energy Modeling System (NEMS).

<u>Source for MSW Costs</u>: CH2M HILL estimate.

$/MWh dollars per megawatt hour

O&M operations and maintenance

## 2.3.1 Biomass

### Overview

For heating applications or electricity generation, biomass can be directly burned in its solid form, or first converted into liquid or gaseous fuels by off-stoichiometric thermal decomposition. Biomass power technologies convert renewable biomass fuels into heat and electricity using modern boilers, gasifiers, turbines, generators, fuel cells, and other methods.

Biomass resource supply includes the use of five general categories of biomass: urban residues, mill residues, forest residues, agricultural residues, and energy crops. Of these potential biomass supplies and the quantities cited below, most forest residues, agricultural residues, and energy crops are not presently economic for energy use. New tax credits or incentives, increased monetary valuation of environmental benefits, or sustained high prices for fossil fuels could make these fuel sources more economic in the future. In addition, forest fires in the past several years in western states have generated increased stimulus to initiate forest thinning programs. Several biomass plants are being proposed in the west to use forest thinnings as a major fuel source.

Wood is the most commonly used biomass fuel for heat and power and is an available biomass resource in Wisconsin. The most economic sources of wood fuels are usually urban residues and mill residues. Urban residues used for power generation consist mainly of chips and grindings of clean, non-hazardous wood from construction activities, woody yard and right-of-way trimmings, and discarded wood products such as waste pallets and crates. Local governments can encourage segregation of clean wood from other forms of municipal waste to help ensure its re-use for mulch, energy, and other markets. Using clean and segregated biomass materials for electricity generation recovers their energy value while avoiding landfill disposal. Development of power resources using urban residues would require coordination with municipalities to develop programs to collect and segregate the waste material and to arrange for its transport to the generating facilities.

Mill residues, such as sawdust, bark, wood scraps, and sludge from paper, lumber, and furniture manufacturing operations are typically very clean and can be used as fuel by a wide range of biomass energy systems. These forest industries are available in Wisconsin, and offer potential fuel sources for power generation. However, these waste materials are often burned in boilers at the plants to produce thermal and/or electric power to run the mills.

Forest residues include underutilized logging residues, imperfect commercial trees, dead wood, and other non-commercial trees that need to be thinned from crowded, unhealthy, fire-prone forests. Because of their sparseness and remote location, these residues are usually more expensive to recover than urban and mill residues.

Agricultural residues are the biomass materials remaining after harvesting agricultural crops. These residues include wheat straw, corn stover (leaves, stalks, and cobs), orchard trimmings, rice straw and husks, and bagasse (sugar cane residue). The agricultural nature of much of Wisconsin suggests that these may be a viable resource within the state. Due to the high costs for recovering most agricultural residues, they are not yet widely used for energy purposes; however, they can offer a sizeable biomass resource if supply infrastructures are developed to economically recover and deliver them to energy facilities.

Energy crops are crops developed and grown specifically for fuel. These crops are carefully selected to be fast growing, drought and pest resistant, and readily harvested alternative crops. Energy crops include fast-growing trees, shrubs, and grasses, such as hybrid poplars, hybrid willows, and switchgrass, respectively. In addition to environmental benefits, energy crops can provide income benefits for farmers and rural land owners.

### Commercially Available

Generating electricity from biomass residues is a proven and commercially available technology. Although many people envision substantial increases in biomass power for the future with “energy crop” plantations forming a primary supply base, this is not feasible in the near term. Presently, “closed-loop” (i.e., sustainably supplied) biomass power projects are at the research and demonstration phase.

### Technical Feasibility

Almost all industrial firms that generate biomass-based electricity do so to achieve multiple objectives. First, most of these firms are producing biomass-related products and have waste streams (e.g., pulping liquor) available as (nearly) free fuel. This makes the cost of self-generation cheaper in many cases than purchasing electricity. Second, using waste to generate electricity also solves otherwise substantial waste disposal problems. Thus, the net cost of generation is much lower to the forest products industry than it would be if its generating facilities were used only to produce electricity, because a sizable waste disposal cost is being avoided. The use of waste-based fuel by some industrial generators to reduce waste disposal costs while simultaneously providing power is an example of synergy among industrial production, environmental concerns, and energy production.

Although the increased availability of forest understorey for fuel would represent an increase in the biomass resource base, any sizable short- to mid-term increase in commercially viable resources is not feasible. Trees require 20 to 40 years to reach full maturity, and while crops such as switchgrass and alfalfa can be grown quickly, the infrastructure for utilizing them for energy is limited. Transportation costs can also be very high given the heat content of the fuel.

Finally, a major limitation on the use of wood for energy within the forest product industry is the fact that wood has a higher value for its primary end uses (e.g., paper, packaging, structural components, insulating materials, panels, composite materials, chemical feedstocks, mulch, and sanitary products) than for fuel. Using more wood for fuel would place upward pressure on the cost of primary products, unless additional forest resources are available near current costs.

In addition to the potential for traditional forest product companies to participate in electric generation, the degree of success which nontraditional participants in the national fiber market will experience must be evaluated. The principal nontraditional participant would likely be an electric utility considering co-firing biomass with coal. Scenarios for large increases in biomass-based power generation usually assume that some fraction of this electricity will come from co-firing. About 15 percent of a co-firing fuel mix can be biomass in theory. In practice, workable proportions may be closer to 5 percent. At the utility sector level, this scenario might imply that a big increase in biomass electricity subsumes participation by many buyers making relatively small, scheduled fiber purchases.

The viability of the utility co-firing scenario, at first glimpse, does not appear favorable. Forest product industries are usually located in close proximity to timber resources. In contrast, utility generating facilities are located according to a number of considerations: water availability, land acquisition capability and costs, environmental and safety issues, transmission and distribution costs, and proximity to population centers, among others. These considerations often do not put utility plants within an economically feasible range (generally 50 miles) of biomass resources; the amount of wood required to satisfy only 5 percent of fuel requirements is far too small to transport wood in a manner similar to that of coal. Thus, some utilities that might wish to co-fire wood are faced with difficulties accessing fuel resources in a cost-effective manner.

### Cost-Effectiveness

The cost to generate electricity from biomass varies depending on the type of technology used, the size of the power plant, and the cost of the biomass fuel supply. In today's direct-fired biomass power plants, generation costs are about $90/MWh.

Currently, the most economically attractive technology for biomass is co-firing. Co-firing systems range in size from 1 MW to 30 MW of biopower capacity.

For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs—the preferred system has transportation distances less than 100 miles. The most economical conditions exist when the energy use is located at the site where biomass residues are generated (i.e., at a paper mill or a sawmill).

## Environmental Compatibility

The primary issue with firing biomass is the control of air emissions. Co-firing of biomass fuels in a coal-fired boiler is advantageous from a renewables standpoint and as an alternative to land disposal.

### *Air*

Biomass used as 5 to 15 percent co-firing in a coal-fired boiler would have similar air emissions and control requirements as those for a conventional pulverized coal or circulating fluidized bed boiler discussed in Section 5 of this report. A 300 MW biomass only fired boiler would have estimated air emissions shown in Table 2-5. A biomass-fired boiler would have low emissions of sulfur dioxide, however emissions of nitrogen oxides, carbon monoxide, particulate matter, and hazardous air pollutants would typically be higher than conventional coal-fired boilers or natural gas turbines. However, it is likely that a well-designed biomass fired power plant with adequate controls would meet the applicable air quality regulatory requirements.

TABLE 2-5
Estimated Annual Air Emissions (tons/year)

| Sulfur Dioxide ($SO_2$) | Nitrogen Oxide ($NO_X$) | Carbon Monoxide (CO) | Particulate Matter ($PM_{10}$) | Hazardous Air Pollutants (HAPs) | Mercury (Hg) | GHGs |
|---|---|---|---|---|---|---|
| 329 | 3,950 | 7,900 | 275 | 1,275 | 0.046 | 2,600,000 |

Notes:

[1] Based on 300 megawatts (MW) wood-fired boiler with low-NOx burners and fabric filter. Average fuel heating value of 6,500 British thermal units (Btu)/pound (lb).

[2] GHGs stands for greenhouse gases.

### *Water*

A biomass-fired power plant would have similar water use requirements as a coal-fired facility. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with coal-fired power plants, dry cooling or zero liquid discharge systems could be used at biomass-fired power plants. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. An adequate source of water would also be required for a typical wet-cooled plant. Stormwater and SPCC plans may also be required.

### *Footprint*

A 20 MW biomass facility would require approximately 10 acres. Therefore, 15 of these plants having a total output of 300 MW would require a total area of approximately 150 acres.

### *General Permitability*

From an air emissions point of view, a 100 percent biomass-fired boiler is not advantageous compared to coal or natural gas options. Environmental permitting would be comparable to that required for a coal-fired unit.

## Dairyland Power Cooperative

Dairyland has seriously investigated the possibility of biomass generation. The key issue for biomass facilities has been the stability of the fuel source. A 20 MW biomass facility using wood waste from pulp mills in Wisconsin was considered but did not advance due to the uncertainty of the wood waste supply. The wood mills involved in the proposed project did not carry through with expansion plans due to the downturn in the U.S. economy.

### Capable of Fulfilling Purpose and Need

Biomass cannot fulfill the need for 300 MW of long-term, cost-effective, and competitive generation of baseload capacity for the Dairyland service area due to its higher levelized cost compared to a conventional pulverized coal-fired power plant.

## 2.3.2 Biogas

### Overview

The same types of anaerobic bacteria that produced natural gas also produce methane rich biogas today. Anaerobic bacteria break down or "digest" organic material in the absence of oxygen and produce "biogas" as a waste product. (Aerobic decomposition, or composting, requires large amounts of oxygen and produces heat.) Anaerobic processes can be managed in a "digester" (an airtight tank) or a covered lagoon (a pond used to store manure) for waste treatment. The primary benefits of anaerobic digestion are nutrient recycling, waste treatment, and odor control. Except in very large systems, biogas production is a highly useful but secondary benefit.

Digester biogas produced in anaerobic digesters consists of methane (50 percent to 80 percent), carbon dioxide (20 percent to 50 percent), and trace levels of other gases such as hydrogen, carbon monoxide, nitrogen, oxygen, and hydrogen sulfide. The relative percentage of these gases in biogas depends on the feed material and management of the process. Anaerobic digesters are used in municipal wastewater treatment plants and on large farm, dairy, and ranch operations for disposal of animal waste.

Landfill biogas (LFG) is created when organic waste in a landfill naturally decomposes. This gas consists of about 50 percent methane, about 50 percent carbon dioxide, and a small amount of non-methane organic compounds. Instead of allowing LFG to escape into the air, it can be captured, converted, and used as an energy source. Using LFG helps to reduce odors and other hazards associated with LFG emissions, and it helps prevent methane from migrating into the atmosphere and contributing to local smog and global climate change.

The various types of biogas can be collected and used as a fuel source to generate electricity using conventional generating technology.

### Commercially Available

Production of electric power from both digester gas and landfill gas has been demonstrated commercially for many years. Dairyland is currently in the process of installing 3 MW of biogas generation in Wisconsin, with plans for an additional 6 MW of biogas generation in 2004 in Iowa and Wisconsin.

### Technical Feasibility

Digester or landfill gas can be used as fuel in reciprocating engines or in gas turbines to generate electricity. A special carburetor is needed for a reciprocating engine because the typical biogas heating value of 500 to 650 British thermal units (Btu)/standard cubic feet (SCF) is significantly lower than the typical heating value of natural gas at 1,000 Btu/SCF.

Gas turbines also require modifications to the combustion chamber to allow use of the lower Btu content biogas.

Pretreatment of the digester or landfill gas is very important to the long-term maintainability and reliability of the engines or turbines. The gas is typically treated to remove hydrogen sulfide, siloxanes, moisture, and particulates prior to combustion.

A recent "Anaerobic Digester Methane to Energy" statewide assessment recommended that 25 Wisconsin communities should consider electrical generation from municipal wastewater treatment plant (WWTP) digester gas. The total power generation potential for all 25 communities is approximately 2.4 MW with a payback period of 4.8 to 8.9 years.

The current U.S. Environmental Protection Agency (EPA) Landfill Methane Outreach Program (LMOP) landfill and project database lists three landfill sites in Wisconsin that have the potential for a landfill gas to electric power project. The total power generation potential for these three projects is approximately 10.2 MW. Two of these landfills are located in Green Bay (Brown County East and West landfills), and the third landfill is located in Janesville (Rock County landfill).

### Cost-Effectiveness

The DOE Energy Information Administration projects the capital cost component of the levelized cost of biogas power to be approximately $37/MWh in 2009. The total levelized cost of biogas power is projected to be approximately $46/MWh (see Table 2-1).

### Environmental Compatibility

There is an environmental benefit of using digester or landfill gas as a fuel in a turbine resource because biogas is a renewable resource. The primary environmental compatibility issue is with air emissions. There are no major water discharge or solid waste/hazardous waste generation issues.

#### *Air*

The air emissions for a turbine firing digester or landfill gas are similar to a natural gas fired turbine. The use of Selective Catalytic Reduction (SCR) for nitrogen oxide ($NO_{x}$) control and catalytic oxidation for carbon monoxide (CO) control may be required.

#### *Water*

There would be no major water discharge issues. A stormwater construction permit and management plan would probably be needed for construction activities. An SPCC plan may be required based on the quantity of oils used and stored onsite.

#### *Footprint*

A 20 MW biogas facility would require approximately 3 acres. Therefore, 15 of these plants having a total output of 300 MW would require a total area of approximately 45 acres.

#### *General Permitability*

Environmental permitting would be fairly straight forward. Depending on the size of the resource, major source Prevention of Significant Deterioration (PSD) permitting may be required.

### Dairyland Power Cooperative

Dairyland has started an initiative to develop biogas facilities on its system. Dairyland has worked with developers to identify potential landfill sites that could host landfill-gas-to-energy projects. Dairyland has identified four landfills in its service territory that have potential for development as landfill-gas-to-energy projects. Only one of the landfill projects, Seven Mile Creek near Eau Claire, Wisconsin, is currently being developed. Two of the three remaining projects have been placed on hold due to concerns about transmission constraints. The third landfill is not producing sufficient gas to support a project. The owner of the third landfill is considering increasing the gas supply to a level sufficient to support a project.

Dairyland has started another initiative to develop up to 25 MW of methane digesters on the Dairyland system. This program would involve placing about thirty 750 KW generating facilities on the Dairyland system. The methane digesters would be installed on member dairy or swine farms. If the goal of 25 MW of methane digesters is met, this will add baseload generation to the Dairyland system because the units will be operated on a continuous basis.

### Capable of Fulfilling Purpose and Need

Biogas power cannot fulfill the need for 300 MW of highly reliable baseload capacity. The amount of digester gas and landfill gas resources is limited within the Dairyland service area.

## 2.3.3 Municipal Solid Waste

### Overview

MSW typically uses a Refuse Derived Fuel (RDF) technology in waste-to-energy facilities to combust trash, garbage, and other combustible refuse. The material is received in its as-discarded form and subjected to segregation of some of the recyclables and shredding prior to being fed into the boilers for combustion. MSW provides energy for power production and at the same time provides waste volume reduction. The plants range upward to 90 MW in size using multiple boilers to provide steam to a single condensing steam turbine generator. There are also a number of mass burn units in operation that burn the MSW directly in its as-discarded form with only the larger non-combustibles removed. Mass burn technology has largely given way to RDF in response to pressure to recycle materials and because the boilers designed to handle RDF are more economical to build.

The components of a typical RDF facility for MSW are discussed below:

- **Refuse receiving area or tipping floor where trash trucks deposit refuse** – A material handling process takes place in which cranes or tractors are used to mix the refuse and remove non-combustible items (such as large appliances) and certain recyclables. The refuse is then conveyed through a shredder and deposited into refuse feed hoppers, which feed the boilers.
- **Combustion and steam generation system** – RDF technologies include various types of combustors including waterwall furnace, refractory furnace, rotary kiln furnace, water-cooled rotary combustor furnace, and controlled air furnace. The waterwall

furnace is the most common in use. Heat from the combustion process is used to generate steam. Steam is routed to a steam turbine generator converting thermal energy to mechanical energy. The steam turbine drives the generator to produce electricity. The steam is exhausted to the condenser, which condenses the steam through cooling by means of cooling or circulating water sourced from either a cooling tower or waterway in the case of once-through cooling.

- **Flue Gas Treatment** – Solid waste combustion generates solid wastes and air pollutants. Residues produced include bottom ash, unburnable organic waste, and fly ash. Fly ash is captured through the use of a fabric filter or baghouse. $NO_x$ and sulfur dioxide ($SO_2$) are also produced and mitigated though use of SCR and Flue Gas Desulfurization (FGD) downstream of the boiler. The alkaline reagents used to capture $SO_2$ also serve to neutralize other acid gases created during the MSW combustion process.

There is the potential for the production of toxic trace metals such as lead, mercury, and beryllium during the combustion process. This can be controlled somewhat by source separation (small batteries are a source of mercury) and by use of selenium filters which are effective in the removal of mercury from flue gas. However, the potential exists to require special disposal precautions due to the presence of these materials in the solid waste. The production of dioxins from the combustion of plastics has been an emissions concern. Dioxin production is controlled by maintaining sufficiently high combustion temperatures in the furnace with supplemental fuel, if required, to incinerate them.

### Commercially Available

MSW technology is available commercially, with operating facilities in multiple states.

### Technical Feasibility

MSW technologies are currently used by municipalities and private industries in many locations in Europe and the United States. New technologies employing gasification of waste material followed by gas combustion to produce steam and power are also being developed.

### Cost-Effectiveness

New MSW to energy plants are not currently cost competitive with conventional power-generation technologies. The capital cost of an MSW power project is approximately $3,500 to $4,000/kW. The total levelized cost of MSW power is projected to be approximately $85/MWh (see Table 2-1). Typically MSW power plants become economical only when landfills for MSW disposal are not available near the collection area and hauling costs become excessive. The MSW power plants can command a tipping fee to offset the high cost of power production, but these need to be in the $50 to $60/ton range in order for the plant to be competitive. These conditions exist in high population density areas such as New York City. Except for small, localized areas, the potential for economical power to be generated in Wisconsin from MSW does not exist. The only MSW facility in Dairyland's service area is the French Island plant, which receives 700 tons/day and generates approximately 15 MW using fluid bed technology. This plant already takes away one of the potential locations for a new MSW power plant facility.

## Environmental Compatibility

The primary environmental benefit of a MSW electric-generation facility is the reduction of wastes that would ordinarily be sent to a landfill for disposal. The primary disadvantage is related to emissions of hazardous air pollutants (HAPs). This issue has made the permitting of MSW electric generation facilities a difficult process in many areas of the country and there is substantial public opposition to siting these facilities.

### *Air*

Estimated air emissions from a 300 MW MSW electric-generation facility are shown in Table 2-6. Emissions of criteria air pollutants are comparable or lower than a coal-fired resource, however, the emissions of hazardous air pollutants including mercury, cadmium, and toxic organics are considerably higher.

TABLE 2-6
Estimated Annual Air Emissions (tons/year)

| Sulfur Dioxide ($SO_2$) | Nitrogen Oxide ($NO_x$) | Carbon Monoxide (CO) | Particulate Matter ($PM_{10}$) | Hazardous Air Pollutants (HAPs) | Mercury (Hg) | Greenhouse Gases (GHGs) |
|---|---|---|---|---|---|---|
| 728 | 936 | 608 | 81 | 281 | 2.89 | 2,588,600 |

Note:

Based on mass burn waterwall combustor; 4,500 British thermal units (Btu)/pound (lb); 2,628,000 tons refuse-derived fuel per year (RDF/yr); Lime Spray Dryer, Fabric Filter, and Selective Catalytic Reduction (at 80 percent control); AP-42 Section 2.1 emission factors.

### *Water*

A MSW-fired power plant using mass burn technology would have similar water use requirements as a coal-fired facility. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with coal-fired power plants, dry cooling or zero liquid discharge systems could be used at biomass-fired power plants. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. An adequate source of water would also be required for a typical wet-cooled plant. Stormwater and SPCC plans may also be required.

### *Footprint*

A 20 MW MSW electric-generation facility would require approximately 7 acres. Therefore, 15 of these plants with a total output of 300 MW would require a total area of approximately 105 acres.

### *General Permitability*

Permitting of a large MSW electric-generation facility would be a long and complicated process. The public communication and hearing process would be extensive. The probability of obtaining a permit to operate is marginal. Significant public opposition can be generated against MSW-fired power plants that can significantly complicate and lengthen the overall permitting process.

## Dairyland Power Cooperative

Dairyland serves rural areas and does not have a municipal customer large enough to support a municipal solid waste-to-energy project.

### Capable of Fulfilling Purpose and Need

MSW cannot fulfill the need for 300 MW of long-term, cost-effective, and competitive generation of baseload capacity for the Dairyland service area due to its higher levelized cost compared to a conventional pulverized coal-fired power plant.

# 2.4 Non-Renewable Combustible Energy Resources

The non-renewable combustible energy resources evaluated in this section are natural gas combined cycle (NGCC), microturbines, pulverized coal (PC), circulating fluidized bed (CFB) coal, and IGCC coal. The electric power cost projections for these energy technologies are shown in Table 2-7 below.

TABLE 2-7
Electric Power Cost Projections for Non-Renewable Combustible Energy Resources
*Levelized Costs for New 300 MW Power Plant (Microturbines @ 30 kW), 80 Percent Capacity Factor*

| | Levelized Costs ($/MWh) | | | | |
|---|---|---|---|---|---|
| **Cost Component** | **Natural Gas Combined Cycle (NGCC)** | **Microturbines** | **Subcritical Pulverized Coal (PC) Powder River Basin (PRB)** | **Circulating Fluidized Bed (CFB) Powder River Basin (PRB) Coal** | **Integrated Gasification Combined Cycle (IGCC) Bit. Coal** |
| Capital | 8.6 | 49.1 | 23.2 | 23.4 | 29.5 |
| Fixed O&M | 3.3 | 8.4 | 6.2 | 6.2 | 11.5 |
| Variable/Fuel | 44.7 | 69.3 | 20.3 | 20.4 | 20.5 |
| Total Busbar Cost[1] | 56.6 | 126.8 | 49.7 | 50.0 | 61.5 |

Source: New Coal Plant Technology Assessment Study for Dairyland Power Cooperation (Dairyland), by Sargent & Lundy, October 2002 (Microturbines are CH2M HILL estimate).

Notes:

[1] Busbar Cost – wholesale cost to generate power at the plant.

$/MWh dollars per megawatt hour

O&M operations and maintenance

## 2.4.1 Natural Gas Combined Cycle

### Overview

Combustion turbine generators (CTGs) are used for simple cycle and combined cycle applications. In simple cycle operation, gas turbines are operated alone, without any recovery of the energy in the hot exhaust gases. Simple cycle gas turbine generators are typically used for peaking or reserve utility power applications, which primarily are operated during the peak summer months (June through September) at less than a total of 2,000 hours per year. Simple cycle applications are rarely used in baseload applications because of the lower heat rate efficiencies compared to a combined cycle configuration.

Combined cycle operation consists of one or more combustion turbine generators exhausting to one or more heat recovery steam generators (HRSGs). The resulting steam generated by the HRSGs is then used to power a steam turbine generator (STG).

There is a wide range of gas turbine size ranging from approximately 1 MW output up to "G" and "H" class machines which are rated at 240 MW and higher. Gas turbines for electric utility services generally range from a minimum of 20 MW for peaking service up to the largest machines for use in combined cycle mode.

### Combustion Turbine Generators

There are two types of combustion gas turbines: heavy industrial "frame" machines and aero-derivative machines which are limited in maximum size to about 50 MW. In a combined cycle plant using frame machines, this provides for more steam, higher superheat temperatures and, therefore, more electrical output from the steam turbine.

Gas turbine powered plants are pre-assembled at the factory, skid or baseplate mounted, and shipped to the site along with other major components including the generator, cooling, lube oil, and electrical modules. Because of the pre-assembled modular approach, field erection hours are significantly reduced, particularly as compared to a coal-fueled plant.

### Heat Recovery Steam Generators

HRSGs extract energy from the combustion turbine exhaust gases in order to produce steam. On larger systems, steam is produced at several pressures and temperatures to make the most efficient use of the energy available. Reheat cycles are incorporated to take advantage of the higher exhaust temperatures available on the larger advanced technology combustion turbines.

### Steam Turbine Generator

The STG converts the energy produced by the HSRG in the form of steam into electrical energy. Larger STG units generally are pedestal mounted with the condenser located underneath the STG.

The condenser condenses the steam leaving the STG and collects the condensate for return to the de-aerator. Condensation is accomplished by dissipating the energy into cooling or circulating water piped to and from a cooling tower (or intake and discharge from a waterway in the case of once-through cooling). Alternatively, an air-cooled condenser may be used on a site that has lack of water availability, cooling tower blowdown disposal problems, cooling tower freeze-up, cooling tower vapor plume problems, or circulating water pollution restrictions (in the case of once-through cooling). Air-cooled condensers present a set of disadvantages: lower cycle efficiency, higher first cost, bigger site, higher noise levels, and higher operation costs.

### Commercially Available

Natural gas combined cycle power plants are available commercially. Most new baseload power plant facilities built in the United States in the past 10 years have used NGCC technology.

### Technical Feasibility

NGCC plants have demonstrated high reliability and low maintenance costs.

### Cost-Effectiveness

The capital cost component of the levelized cost of NGCC power is very low at approximately $9/MWh. However, the total levelized cost of NGCC power is projected to be relatively high at approximately $57/MWh(see Table 2-7).

Most of the power-generation cost for NGCC is from the variable/fuel cost at $45/MWh. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels.

Weather is the largest single factor affecting gas prices and the most unpredictable. Traditionally, demand for natural gas peaks in the coldest months, but with the nation's power increasingly being generated by natural gas, demand also spikes in summer, when companies fire up peaking plants to provide more power for cooling needs.

### Environmental Compatibility

A natural gas combined cycle facility has lower criteria, HAP, and carbon dioxide ($CO_2$) emissions than a comparable coal-fired alternative. There are no major water discharge or solid waste/hazardous waste generation issues.

#### *Air*

Estimated air emissions for a 300 MW natural gas combined cycle resource are shown in Table 2-8. A major source PSD permit would be required. Current best available control technology (BACT) would require SCR for $NO_x$ control and catalytic oxidation for CO control. There would also be particulate matter ($PM_{10}$) emissions from a cooling tower. There could also be other minor sources of air emissions from miscellaneous support equipment such as diesel/natural gas emergency generators and fire pumps.

TABLE 2-8
Estimated Annual Air Emissions (tons/year)

| Sulfur Dioxide ($SO_2$) | Nitrogen Oxide ($NO_x$) | Carbon Monoxide (CO) | Particulate Matter ($PM_{10}$) | Hazardous Air Pollutants (HAPs) | Mercury (Hg) | Greenhouse Gases (GHGs) |
|---|---|---|---|---|---|---|
| 5.6 | 115 | 232 | 68 | 1.7 | .01 | 1,250,000 |

Note:

Based on 300 megawatts (MW) Combined Cycle Turbine; 8,000 British thermal units (Btu)/gross kilowatt hours (kWh) heat rate; 3 parts per million (ppm) $NO_x$ with selective catalytic reduction (SCR); 10 ppm CO with catalytic oxidation; U.S. Department of Energy (DOE) Energy Information Administration (EIA) Carbon Dioxide ($CO_2$) factor of 952 pounds (lb)/megawatt hours (MWh).

#### *Water*

A NGCC power plant using wet cooling would have similar but lower water use requirements as a coal-fired facility. In a typical combined cycle plant, approximately one-third of the total generation capacity comes from the steam cycle, two-thirds is generated directly by the combustion turbine/generator equipment. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with coal-fired power plants, dry cooling or zero liquid discharge systems could be used at NGCC power plants. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. An adequate source of water would also be required for a typical wet-cooled plant. Stormwater and SPCC plans may also be required.

#### *Footprint*

A 300 MW natural gas combined cycle turbine facility would require approximately 25 acres.

#### *General Permitability*

Permitting of a NGCC power plant typically requires numerous permits and approvals from federal, state, and local regulatory agencies. A major source PSD air construction permit would be required. However, based on the relatively low emissions compared to other alternatives, the application, review, and public comment processes would be fairly straight forward.

### Dairyland Power Cooperative

The Elk Mound Station gas turbines (71 MW) were the last generating facility installed on the Dairyland system. Dairyland has considered the addition of natural gas combined cycle units. The need for baseload energy and the price volatility of natural gas were the deciding factors in Dairyland's decision not to pursue additional natural gas fired units.

### Capable of Fulfilling Purpose and Need

A NGCC power plant is not capable of fulfilling the purpose and need for Dairyland because it is subject to highly variable natural gas fuel costs.

## 2.4.2 Microturbines

### Overview

Microturbines are small electricity generators that burn gaseous and liquid fuels to create high-speed rotation that turns an electrical generator. Current microturbine technology is the result of development work in small stationary and automotive gas turbines, auxiliary power equipment, and turbochargers, much of which was pursued by the automotive industry beginning in the 1950s. Microturbines entered field testing around 1997 and began initial commercial service in 2000.

The size range for microturbines commercially proven and currently available is from 30 to 70 kW, compared to conventional gas turbine sizes that range from approximately 1 to 240 MW. Microturbines operate at high speeds and may be used in simple cycle or cogeneration systems. They are able to operate on a variety of fuels, including natural gas, sour gas, landfill gas, anaerobic digester gas and diesel fuel/distillate heating oil. In resource recovery applications, they burn waste gases that would otherwise be flared.

Microturbines are ideally suited for distributed generation applications due to their small power output and space requirement, flexibility in connection methods, ability to be stacked in parallel to serve larger loads, ability to provide stable and reliable power, and low emissions. Types of applications include stand-alone primary power, backup/standby power, peak shaving and primary power (grid parallel), primary power with grid as backup, resource recovery and cogeneration.

### Commercially Available

Microturbines are currently operating in resource recovery operations at oil and gas production fields, wellheads, coal mines, landfills and WWTP digester gas operations, where byproduct gases serve as essentially free fuel. Reliable unattended operation is important since these locations may be remote from the grid. Target customers include financial services, data processing, telecommunications, office buildings and other commercial sectors that may experience costly downtime when electric service is lost from the grid.

Capstone and Ingersol Rand (IR) are currently the only commercial manufacturers providing microturbines for continuous operation in natural gas and resource recovery applications. Capstone Turbine Corporation, one of the world's leading manufacturers of microturbines, currently offers two (2) commercially available sizes of microturbines—the 30 kW and the 60 kW. IR EcoWorks (PowerWorks) currently offers a 70-kW turbocharged microturbine.

### Technical Feasibility

Microturbine design life is estimated to be in the 40,000 to 80,000 hour range. However, while units have demonstrated reliability, they have not been in commercial service long enough to provide definitive data.

### Cost-Effectiveness

Microturbine power plants are not currently cost competitive with conventional power-generation technologies. The capital cost of a microturbine unit is approximately $2,500/kW. The total levelized cost of microturbine power is projected to be approximately $127/MWh (see Table 2-7). Typically, microturbine units become economical for remote locations, when grid power is not available, and when low cost waste fuel is available.

### Environmental Compatibility

The primary environmental compatibility issue is with air emissions. There are no major water discharge or solid waste/hazardous waste generation issues.

#### *Air*

The air emissions for a microturbine burning natural gas are similar to a combustion turbine without add-on controls on a lb/MWH basis. However, a typical combined cycle installation would have both SCR for $NO_x$ control and catalytic oxidation for CO control. Thus, on a per MW basis, $NO_x$ and CO emissions from a microturbine are substantially higher. Estimated air emissions for a 30 kW natural gas simple cycle unit are shown in Table 2-9.

TABLE 2-9
Estimated Annual Air Emissions (tons/year)

| $SO_2$ | $NO_x$ | CO | $PM_{10}$ | HAPs | Hg | GHGs |
|---|---|---|---|---|---|---|
| 0.005 | 0.06 | 0.15 | 0.01 | 0.002 | - | 203 |

Notes: Based on 30 kW microturbine; 0.437 MMBtu/hr heat input; 80% capacity factor; Dry Low $NO_x$ combustion; emission factors based on AP-42 Section 3.1 and EPA paper, *Technology Characterization: Microturbines*, March 2002.

#### *Water*

A small microturbine installation is self-contained. There are no water supply or wastewater discharge issues.

#### *Footprint*

A 30 kW natural gas simple cycle microturbine unit would require approximately 12 square feet of floor space, and a 70-kw microturbine would require approximately 24 square feet of floor space. It would require approximately 4,300 to 10,000 microturbines, based on the commercially size range of 30 to 70 kW each, to generate 300 MW of power. The total space requirement for 300 MW of microturbine installations would be approximately 100,000 to 120,000 square feet, or 2.3 to 2.8 acres.

#### *General Permitability*

Environmental permitting requirements would be dependent on the maximum number of microturbines to be installed at a specific location. A minor source air construction permit may be required. It is highly unlikely that PSD permitting would be required. Approximately 666 30-kW microturbines would have to be installed at a facility to trip PSD significance levels (40 tons $NO_x$ or $SO_2$, 100 tons CO).

### Dairyland Power Cooperative

Dairyland is not pursuing microturbine projects due to cost and limited size.

### Capable of Fulfilling Purpose and Need

Microturbine units cannot fulfill the need for 300 MW of long-term, cost-effective, and competitive generation of baseload capacity for the Dairyland service area due to its higher levelized cost compared to a conventional pulverized coal-fired power plant. Microturbines are not well suited for baseload operations; they are typically used in remote locations burning waste gases where grid power is not available.

## 2.4.3 Pulverized Coal

### Overview

Pulverized coal plants represent the most mature of technologies considered in this analysis. Coal plants, although having a high capital cost relative to some alternatives, have an advantage over other non-renewable combustible energy source technologies due to the relative low and stable cost of coal.

Modern pulverized coal plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Coal is most often delivered by unit train to the site, although barges or trucks are also used. Many plants are situated adjacent to the coal source where coal delivery can be by conveyor. Coal can have various characteristics with varying Btu heating values, sulfur content, and ash constituents. The source of coal and coal characteristics can have a significant effect on the plant design in terms of coal-handling facilities and types of pollution control equipment required.

Regardless of the source, the plant coal-handling system unloads the coal, stacks out the coal, reclaims the coal as required, and crushes the coal for storage in silos. Then the coal is fed from the silos to the pulverizers and blown into the steam generator. The steam generator mixes the pulverized coal with air, which is combusted, and in the process produces heat to generate steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to product electricity.

The steam generator produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash, $NO_x$, and $SO_2$. The pollution control equipment includes either a fabric filter (baghouse) or electrostatic precipitator for particulate control (fly ash), SCR for removal of $NO_x$, and FGD system for removal of $SO_2$. Limestone is required as the reagent for the most common wet FGD process, limestone forced oxidation desulfurization. A limestone storage and handling system is a required design consideration with this system.

Coal plants produce several forms of liquid and solid waste. Liquid wastes include cooling tower blowdown, coal pile runoff, chemicals associated with water treatment, ash conveying water, and FGD wastewater. Solid wastes include bottom and fly ash and FGD solid wastes. Disposal of these wastes is a major factor is plant design and cost considerations.

### Commercially Available

Pulverized coal is available commercially, with a long history of being the technology of choice for large base-load utility units.

### Technical Feasibility

Pulverized coal has been used for large utility units for over 50 years. The technology has evolved in areas such as emissions and controls to improve its technical feasibility.

### Cost-Effectiveness

The relatively low fuel cost for coal results in a low cost of electricity. Over half of the electricity generated in this country comes from coal-fired units, almost all of it from PC units. There have not been many new coal units in recent years, but current fuel costs result in coal being the economical choice for large additions of new generation in areas with reasonable access to coal.

### Environmental Compatibility

Environmental impacts associated with pulverized coal resources include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash.

#### *Air*

Estimated air emissions for a 300 MW pulverized coal resource are shown in Table 2-10. A major source PSD permit would be required. Current BACT would require low-$NO_x$ burners and SCR for $NO_x$ control, lime dry FGD or limestone/lime wet FGD for $SO_2$ control, and a fabric filter or electrostatic precipitator (ESP) for particulate control. There would also be $PM_{10}$ emissions from cooling towers and coal, ash, and limestone or lime material handling operations. There could also be other sources of air emissions from miscellaneous support equipment such as diesel/natural gas emergency generators, fire pumps, or the installation of an auxiliary boiler. A case-by-case, maximum achievable control technology (MACT) analysis would be required for mercury, other trace metals in the coal, organics, and acid gases.

TABLE 2-10
Estimated Annual Air Emissions (tons/year)

| Sulfur Dioxide ($SO_2$) | Nitrogen Oxide ($NO_x$) | Carbon Monoxide (CO) | Particulate Matter ($PM_{10}$) | Hazardous Air Pollutants (HAPs) | Mercury (Hg) | Greenhouse Gases (GHGs) |
|---|---|---|---|---|---|---|
| 1,182 | 828 | 1,892 | 177 | 36 | 0.04 | 2,575,000 |

Note:

Based on pulverized coal boiler; Powder River Basin (PRB) coal 8,000 British thermal units (Btu)/pounds (lb); 9,000 Btu/gross kilowatt hours (kWh) heat rate; 1,391,294 tons/yr coal; lime spray dryer, fabric filter and selective catalytic reduction; best available control technology (BACT) emission factors; U.S. Department of Energy (DOE) Energy Information Agency (EIA) Carbon Dioxide ($CO_2$) factor of 1,970 lb/megawatt hours (MWh).

#### *Water*

Coal plants require a reliable long-term source of water. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with other generating technologies that utilize a steam cycle, dry cooling or zero liquid discharge systems are an option to reduce overall water consumption and discharge. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. Stormwater and SPCC plans may also be required.

#### *Footprint*

A 300 MW pulverized coal facility would require approximately 90 to 160 acres.

#### *General Permitability*

Permitting of a pulverized coal plant typically requires numerous permits and approvals from federal, state, and local regulatory agencies. A major source PSD air construction permit would be required. The permit application, agency review and follow-up, and public comment process can be extensive for a new coal-fired resource. It is expected that it would take approximately 18 months from the start of the application preparation to the agency's initial permit approval.

### Dairyland Power Cooperative

Dairyland currently owns and operates 760 MW of coal-fired generation and is currently in the process of evaluating the option to add an additional 400 MW of baseload coal-fired generation to its system. Dairyland's coal-fired generation is used to generate the majority of its current baseload and intermediate load requirements. Because of the increase in base load on the Dairyland system over the next 20 years (see section on Purpose and Need in this document), Dairyland has identified the option of a 400 MW coal-fired to meet this growing demand.

### Capable of Fulfilling Purpose and Need

Pulverized coal is capable of fulfilling Dairyland's need for new generation in 2009 and beyond.

### 2.4.4 Circulating Fluidized Bed Coal

#### Overview

In the mid 1980s, an alternative to the standard PC fired plant emerged called CFB combustion. The fuel delivery system is similar, but somewhat simplified, to that of a pulverized coal unit but with a greater fuel cost advantage in that a wider range of fuels and lesser quality of fuel can be used (coal, coke, biomass, etc.). The bed material is composed of fuel, ash, sand, and sorbent (typically limestone). CFB units compete in the marketplace in sizes up to 300 MW with larger sizes available soon.

CFB combustion temperatures are significantly lower than a conventional boiler at 1,500 to 1,600 degrees Fahrenheit (ºF) vs. 3,000ºF which results in lower $NO_x$ emissions and reduction of slagging and fouling characteristic of PC units. In contrast to a PC plant, sulfur dioxide can be partially removed during the combustion process by adding limestone to the fluidized bed.

The plant fuel handling system unloads the fuel, stacks out the fuel, crushes or otherwise prepares the fuel for combustion, and reclaims the fuel as required. The fuel is usually fed into to the CFB by gravimetric feeders. In the CFB the fuel is combusted and in the process produces steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to product electricity.

The CFB produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash and sulfur dioxides. $NO_x$ emissions can be mitigated through use of selective non-catalytic reduction (SNR) using ammonia injection, usually in the upper area of the combustor. The pollution control equipment external to the CFB includes either a fabric filter (baghouse) or electrostatic precipitator for particulate control (fly ash), and a polishing FGD system for additional removal of sulfur dioxides to achieve similar levels to PC units. Limestone is required for the most common wet FGD process, limestone forced oxidation desulfurization, and also as sorbent for the fluidized bed.

Similar to a PC plant, a CFB plant produces several forms of liquid and solid waste. Liquid wastes include cooling tower blowdown, chemicals associated with water treatment, ash conveying water, and FGD wastewater. Solid wastes include bed and fly ash and FGD solid wastes. As with PC fired units, disposal of these wastes is a major factor in plant design and cost considerations.

#### Commercially Available

The CFB technology is available commercially. The 300 MW unit size is similar in size to the largest CFB units in operation. The CFB boiler suppliers indicate a willingness to provide larger units with full commercial guarantees.

#### Technical Feasibility

CFB power plants have demonstrated technical feasibility in commercial utility applications for about 20 years. The technology has evolved during that time to improve its technical feasibility.

### Cost-Effectiveness

CFB units in the 300 MW size are cost-competitive with other technologies. CFB units are generally installed to burn poor quality or waste coals, but offer no advantage for the Power River Basin coals being considered by Dairyland.

### Environmental Compatibility

Environmental impacts associated with a CFB coal resource include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash. A CFB design does have the advantage of burning a wider range of fuels including waste materials such as coke or renewable biomass.

#### *Air*

Estimated air emissions for a 300 MW CFB resource are shown in Table 2-11. While the air emissions exiting a CFB boiler (especially $NO_x$, $SO_2$, and CO) are lower than a conventional pulverized coal boiler, the final stack emissions would be similar based on the use of add-on control equipment. A major source PSD permit would be required. Current BACT would require low-$NO_x$ burners and SCR for $NO_x$ control, limestone FGD for $SO_2$ control, and a fabric filter or ESP for particulate control. There would also be $PM_{10}$ emissions from cooling towers and coal, ash, and limestone material handling operations. There could also be other sources of air emissions from miscellaneous support equipment, such as diesel/natural gas emergency generators, fire pumps, or the installation of an auxiliary boiler. A case-by-case MACT analysis would be required for mercury, other trace metals in the coal, organics, and acid gases.

TABLE 2-11
Estimated Annual Air Emissions (tons/year)

| Sulfur Dioxide ($SO_2$) | Nitrogen Oxides ($NO_x$) | Carbon Monoxide (CO) | Particulate Matter ($PM_{10}$) | Hazardous Air Pollutants (HAPs) | Mercury (Hg) | Greenhouse Gases (GHGs) |
|---|---|---|---|---|---|---|
| 1,182 | 828 | 1,892 | 177 | 36 | 0.04 | 2,575,000 |

Note:

Based on circulating fluidized bed boiler; Powder River Basin (PRB) coal 8,000 British thermal units (Btu)/pound (lb); 9,000 Btu/gross kilowatt hours (kWh) heat rate; 1,391,294 tons/yr coal; limestone flue gas desulfurization (FGD), fabric filter and selective non-catalytic reduction; best available control technology (BACT) emission factors; U.S. Department of Energy (DOE) Energy Information Agency (EIA) Carbon Dioxide ($CO_2$) factor of 952 lb/megawatt hours (MWh).

#### *Water*

Coal plants require a reliable long-term source of water. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with other generating technologies that utilize a steam cycle, dry cooling or zero liquid discharge systems are an option to reduce overall water consumption and discharge. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. Stormwater and SPCC plans may also be required.

#### *Footprint*

A 300 MW CFB facility would require approximately 90 to 160 acres.

#### *General Permitability*

Permitting of a CFB coal plant typically requires numerous permits and approvals from federal, state, and local regulatory agencies. A major source PSD air construction permit would be required. The permit application, agency review and follow-up, and public comment process can be extensive for a new coal-fired resource. It is expected that it would take approximately 18 months from the start of the application preparation to the agency's initial permit approval.

### Capable of Fulfilling Purpose and Need

The CFB technology is capable of fulfilling Dairyland's need for new generation in 2009.

## 2.4.5 Integrated Gasification Combined Cycle Coal

### Overview

Coal gasification for use in power generation reacts coal with steam and oxygen under high pressure and at high temperature to produce a gaseous mixture consisting primarily of hydrogen and carbon monoxide. The gaseous mixture requires cooling and cleanup to remove contaminants and pollutants to produce a synthesis gas suitable for use in the combustion turbine portion of a combined cycle unit. The combined cycle portion of the plant is similar to a conventional combined cycle. The most significant differences in the combined cycle are modifications to the combustion turbine to allow use of a 250 to 300 Btu/SCF gas and steam production via heat recovery from the raw gas in addition to the combustion turbine exhaust (HRSG). Specifics of a plant design are influenced by the gasification process, degree of heat recovery, and methods to clean up the gas.

### Commercially Available

The current and near-term IGCC plants must be viewed as technically feasible, but not delivering the cost and performance to be economically attractive. The current IGCC plants are providing good information about the technology, but not demonstrating the necessary cost of electricity to expect the technology to be available commercially in time frame to support Dairyland's needs.

### Technical Feasibility

IGCC has been demonstrated in a few commercial-scale facilities. A variety of coals have been gasified, the resulting gases have been cleaned up to allow use in combustion turbines, and electricity has been generated. However, the capital cost and performance in a number of areas have not been as attractive as planned. The troublesome areas for IGCC have included high-temperature heat recovery and hot gas cleanup. An important part of achieving an attractive heat rate is generation of high pressure and temperature steam from the high-temperature raw gas generated by gasifying coal. The temperature of the raw gas is dependent on the gasification process and the coal. Slagging gasifiers, such as the Texaco process, typically generate gases in the 2500 to 2800°F range. These high-temperature gases containing corrosive compounds, such as $H_2S$ create a very demanding environment for the generation of high pressure and temperature steam. The reliable generation of steam under these conditions has not been demonstrated in a commercial application. Alternatives not recovering the heat in the raw gas, such as direct quenching of the gas, result in lower efficiencies. It is also attractive from an efficiency perspective to provide clean gas to the combustion turbine at an elevated temperature without cooling and reheating, hence the desire to use hot gas cleanup. Again, this demanding service has not been reliably demonstrated in a commercial application, resulting in less efficient approaches being used for current plants.

### Cost-Effectiveness

IGCC has the potential to use coal in a more efficient process and with lower emissions than conventional coal power plants. The combined cycle portion of the process is attractive from a capital cost perspective compared to a conventional coal plant, but the addition of gasification, coal feeding, gas cooling, gas cleanup, and oxygen plant result in an overall cost that is higher than a conventional coal plant. Higher efficiency than a conventional coal plant could justify higher capital costs. However, the currently demonstrated capital cost is about 30 percent higher and efficiency is about 5 percent better than a conventional coal plant. This cost and performance comparison does not result in a cost of electricity that is lower than a conventional coal plant. The reported cost for the Polk County IGCC Plant is about $1,800/kW and the net plant heat rate (NPHR) target at full load is 9,400 Btu/kilowatt hours (kWh). The annual NPHR has ranged from 9,877 Btu/kWh to 10,725 Btu/kWh. The target for IGCC NPHR in the future is about 8,000 Btu/kWh. Future capital costs are expected to be about the same as conventional coal units of similar size. When those conditions are realized, IGCC should be a cost-effective alternative to conventional coal.

### Environmental Compatibility

The overall environmental impacts from an IGCC design would be between those of a natural gas combined cycle turbine resource and a coal resource. Environmental impacts would include air emissions, water/wastewater discharge, and solid waste disposal.

#### *Air*

Estimated air emissions for a 300 MW IGCC resource are shown in Table 2-12. The emissions shown are based on the Tampa Electric Polk Station project. A major source PSD permit would be required. Based on a BACT analysis additional control may be required including SCR for $NO_x$ control and catalytic oxidation for CO control. There would also be $PM_{10}$ emissions from a cooling tower. There could also be other minor sources of air emissions from the IGCC process and miscellaneous support equipment such as diesel/natural gas emergency generators and fire pumps.

TABLE 2-12
Estimated Annual Air Emissions (tons/year)

| Sulfur Dioxide ($SO_2$) | Nitrogen Oxides ($NO_x$) | Carbon Monoxide (CO) | Particulate Matter ($PM_{10}$) | Hazardous Air Pollutants (HAPs) | Mercury (Hg) | Greenhouse Gases (GHGs) |
|---|---|---|---|---|---|---|
| 1,550 | 975 | 429 | 75 | NA | NA | 2,050,000 |

Note:

Emissions based on Tampa Electric Polk Power Station integrated gasification combined cycle (IGCC) Project. HAPs and Hg emissions were not reported but are expected to be lower than a conventional pulverized coal boiler but higher than a conventional natural gas combined cycle turbine. Carbon Monoxide ($CO_2$) emissions estimated to be 20 percent less than conventional pulverized coal boiler.

#### *Water*

An IGCC power plant using wet cooling would have similar but lower water use requirements as a coal-fired facility. In a typical combined cycle plant, approximately one-third of the total generation capacity comes from the steam cycle, two-thirds is generated directly by the combustion turbine/generator equipment. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with coal-fired power plants, dry cooling or zero liquid discharge systems could be used at IGCC power plants. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. An adequate source of water would also be required for a typical wet-cooled plant. Stormwater and SPCC plans may also be required.

#### *Footprint*

A 300 MW IGCC facility would require approximately 180 acres.

#### *General Permitability*

Permitting of an IGCC power plant typically requires numerous permits and approvals from federal, state, and local regulatory agencies. A major source PSD air construction permit would be required. However, based on the relatively low emissions compared to other alternatives, the application, review, and public comment processes would be fairly straight forward.

The permit application, agency review and follow-up, and public comment process would probably not be as extensive as a new coal-fired resource. EPA regional offices and state regulatory agencies are looking favorably at both the CFB and IGCC technologies.

### Dairyland Power Cooperative

Dairyland does not currently have any IGCC generating capacity in its system and does not anticipate adding this technology to their generation portfolio. IGCC is less cost-effective than more conventional coal-fired power plants, represents a less well-developed technology, and has only limited environmental benefits.

### Capable of Fulfilling Purpose and Need

The IGCC technology is judged not capable of fulfilling the Purpose and Need for new generation. The reasons for this are the requirement for a high level of reliability and long-term, cost-effective, and competitive generation of power. There are problem areas, discussed above, that have not demonstrated acceptable reliability. The current approaches to improving reliability in these areas result in less efficient facilities, negatively impacting the cost-effectiveness. DOE has a program, Vision 21, with the goal of providing clean coal power-generation alternatives which includes improving the cost-competitiveness of IGCC. However, the current DOE time frame (by 2015) does not support Dairyland’s 2009 needs.

# 3.0 Conclusions

The projected levelized costs for new utility power generation plants in the Wisconsin area are shown in Table 3-1. The power-generation technologies presented with their respective competitive costs are wind, hydroelectric, biogas, NGCC, PC, and CFB coal. However, wind and hydroelectric power have average capacity factors of 30 and 45 percent, respectively, and can not be used for baseload service.

TABLE 3-1
Levelized Costs for New Utility Power Generation Plants
*MAPP Region*

| | Levelized Costs ($/MWh) | | | | |
|---|---|---|---|---|---|
| **Type of Power Plant** | **Capital Cost** | **Fixed O&M Cost** | **Variable / Fuel Cost** | **Total Busbar Cost[1]** | **Average Capacity Factor** |
| Wind | 39.3 | 8.0 | 0 | 47.3 | 30 |
| Solar - Photovoltaic | 151.9 | 4.7 | 0 | 156.6 | 24 |
| Solar - Thermal | 146.7 | 21.0 | 0 | 167.7 | 33 |
| Hydroelectric | 17.0 | 2.6 | 4.0 | 23.6 | 33 |
| Geothermal | N/A | N/A | N/A | 50-80 | 80 |
| Biomass | 30.0 | 45.0 | 15.0 | 90.0 | 80 |
| Biogas | 37.0 | 6.6 | 3.0 | 46.5 | 80 |
| Municipal Solid Waste (MSW) | 32.8 | 38.9 | 13.0 | 84.8 | 80 |
| Natural Gas Combined Cycle (NGCC) | 8.6 | 3.3 | 44.7 | 56.6 | 80 |
| Microturbines | 49.1 | 8.4 | 69.3 | 126.8 | 80 |
| Pulverized Coal (PC) | 23.2 | 6.2 | 20.3 | 49.7 | 80 |
| Circulating Fluidized-Bed (CFB) Coal | 23.4 | 6.2 | 20.4 | 50.0 | 80 |
| Integrated Gasification Combined Cycle (IGCC) Coal | 29.5 | 11.5 | 20.5 | 61.5 | <80 |

Source: See Tables 2-1, 2-2, and 2-5.

Note:

[1] Busbar Cost – wholesale cost to generate power at the plant.

$/MWh dollars per megawatt hour

O&M operations and maintenance

A comparison of the alternate technologies regarding their capability of meeting the Dairyland purpose and need criteria is shown in Table 3-2. Only the PC and CFB coal technologies are capable of meeting all of the criteria. Although NGCC offers the average capacity factor Dairyland needs, and the capital cost component of the levelized cost of NGCC power is very low at approximately $9/MWh versus $23/MWh for a PC unit, the total levelized cost of NGCC power is projected to be approximately $57/MWh versus $50/MWh for a pulverized coal plant. This coupled with the volatility of natural gas prices results in NGCC being a costly option for Dairyland's member cooperatives and customers. CFB units in the 300 MW size are cost-competitive with PC, but CFB units are generally more cost-effective than PC for poor quality or waste coals. They do not offer any advantage for burning the Power River Basin coals being considered by Dairyland.

TABLE 3-2
Comparison of Alternate Power Generation Technologies
*Dairyland*

| Type of Power Plant | Capable of Meeting Purpose and Need Criteria | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **300 MW in 2009** | **Baseload Operation** | **Environmentally Permitable** | **Cost-effective** | **Fuel Cost Stability** | **High Reliability** | **Commercially Available** | **Meets All Criteria** |
| Wind | Yes | No | Yes | Yes | Yes | Yes | Yes | No |
| Solar – Photovoltaic | No | No | Yes | No | Yes | Yes | Yes | No |
| Solar – Thermal | No | No | Yes | No | Yes | No | Yes | No |
| Hydroelectric | No | No | Difficult | Yes | Yes | Yes | Yes | No |
| Geothermal | No | Yes | Yes | N/A | Yes | Yes | No | No |
| Biomass | No | Yes | Yes | No | Yes | Yes | Yes | No |
| Biogas | No | Yes | Yes | Yes | Yes | Yes | Yes | No |
| Municipal Solid Waste (MSW) | No | Yes | Difficult | No | Yes | No | Yes | No |
| Natural Gas Combined Cycle (NGCC) | Yes | Yes | Yes | Yes | No | Yes | Yes | No |
| Microturbines | No | No | Yes | No | No | Yes | Yes | No |
| Pulverized Coal (PC) | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Circulating Fluidized-Bed (CFB) Coal | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Integrated Gasification Combined Cycle Coal | Yes | Yes | Yes | No | Yes | No | Yes | No |

Note:
Based on alternate power plant options located within or adjacent to the Dairyland System.

# 4.0 Notes

[1] Load & Capability data are from Dairyland Planning Division "2003 Load & Capability Forecast". This forecast is based largely on the 2000 Load Forecast Final Report dated December 2000 done by Power System Engineering, Inc. A new forecast is expected to be published in June 2003. Data are presented in a format similar to the one used to report to Mid-Continent Area Power Pool (MAPP) and consistent with the Load & Capability.

| | | |
|---|---|---|
| 1A. | Seasonal Maximum Demand | 914 MW |
| 1B. | Demand at Time of Seasonal System Demand | 914 |
| 2. | Schedule L Purchases at Time of SSD | 0 |
| 3. | Seasonal System Demand (1B-2) | 914 |
| 4. | Annual System Demand | 914 |
| 5. | Firm Purchases – Total | 0 |
| 6. | Firm Sales – Total | 4 |
| 7. | Seasonal Adjusted Net Demand (3-5+6) | 918 |
| 8. | Annual Adjusted Net Demand (4-5+6) | 918 |
| 9. | Net Generating Capability | 1113 |
| 10. | Participation Purchases - Total | 0 |
| 11. | Participation Sales – Total[3] | 171 |
| 12. | Adjusted Net Capability (9+10-11) | 942 |
| 13. | Net Reserve Capacity Obligation (8*15%) | 138 |
| 14. | Total Firm Capacity Obligation (7+13) | 1056 |
| 15. | Surplus or Deficit Capacity (12-14) | (114) |

**Total Seasonal Demand (1A)**

| | |
|---|---|
| Class A Demand | 767 |
| Class D Demand | 49 |
| New GEN~SYS Municipal Demand | 17 |
| Dairyland Load Control | (66) |
| Weather Adjustment[6] | 98.2 |
| Dairyland A2 Load Control | (10.9) |
| Dairyland System Losses | 59.4 |
| Total | 914 (913.7) |

Net Generating Capability (Line 9) based on 2002 Summer MAPP Urge Ratings

| | |
|---|---|
| Seven Mile Creek Landfill[7] | 3 |
| Elk Mound Generating Station | 72 |
| JPM Turbine Upgrade[7] | 25 |
| **Genoa Station #3** | **353** |
| **JP Madgett Station** | **367** |
| Alma #1 | 19.8 |
| Alma #2 | 20.2 |
| Alma #3 | 20.4 |
| Alma #4 | 56 |
| Alma #5 | 77.7 |
| Flambeau Hydro Station | 22.6 |
| Municipal Under Contract | 76.95 |
| Total | 1113.65 |

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