Facts Concerning the Consumption and Production of Electric Power in Iowa

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Acknowledgements

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1.0 INTRODUCTION AND BACKGROUND

Basic characteristics of electricity supply and demand include the following:[1]

- electricity must usually be generated at the same time that it is consumed since storing electricity is difficult and expensive;
- electricity consumption varies widely depending on the time of day, the season, and the weather;
- electricity moves at the speed of light and many operational decisions must be implemented very quickly or automatically;
- changes anywhere in the interconnected electrical system impact all other points of the system;
- electric system conditions are constantly changing with changes in demand, generation, and transmission;
- the addition of new electric infrastructure is capital intensive and subject to long lead times; and
- a reliable supply of electricity is essential to economic development and human satisfaction.

These characteristics require a complex and extensive state and regional electric utility infrastructure to efficiently provide reliable electric service. The data presented in this report characterize this electric utility infrastructure for the state of Iowa. This characterization is the first step in assessing and evaluating the production, delivery, and use of electricity in Iowa. Any stakeholder group may use the data compiled in this report to determine policy implications and recommendations for Iowa's electric utility industry. This report does not assess or evaluate the data.

1.1 Background

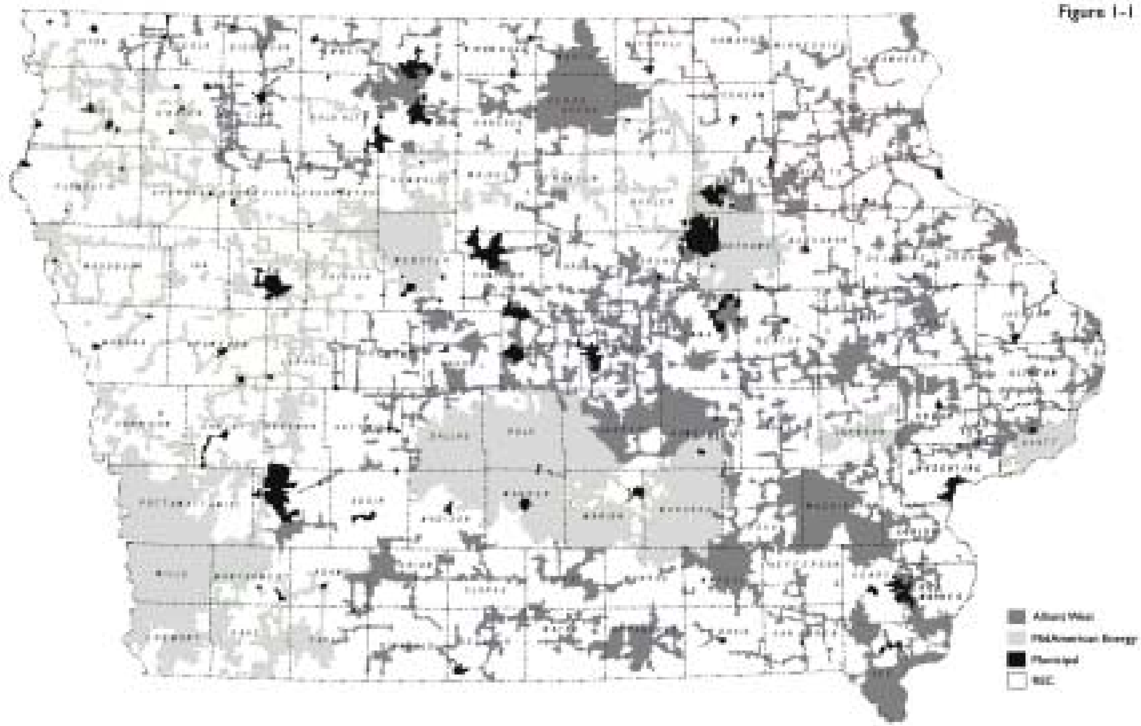
In order to understand the data presented in the report, it is important to have a basic understanding of the electric utility industry including the different types of utility companies and the interconnected transmission grid. Subsection 1.1 provides this basic information.

1.1.1 Types of Utilities

Iowa's electric customers are served by three basic utility types: investor-owned utilities (IOUs), rural electric cooperatives (RECs), and municipal (or publicly owned) utilities. Each utility company serves an exclusive service territory. Figure 1-1 shows the service territories served by each type of utility.

[1] The characteristics are, in part, gleaned from the "Draft Working Model for Restructuring the Electric Utility Industry in Virginia, Chapter 2: Reliability," November 1997.

Figure 1-1



IOUs are publicly held, for-profit companies primarily serving urban areas of the state. Iowa is served by two IOUs - Alliant Energy (Alliant) and MidAmerican Energy Company (MidAmerican). Alliant is comprised of three operating companies: Interstate Power (Interstate), IES Utilities (IES), and Wisconsin Power and Light (WPL). Interstate and IES primarily serve Iowa and are characterized throughout the report as Alliant-West. Data incorporating WPL (which does not serve Iowa) are removed where possible. IOU retail rates and service are regulated by the IUB. Wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

RECs are locally owned, not-for-profit utilities controlled by a board of directors elected by the consumers they serve. Iowa's RECs provide electric service to more than 180,000 homes, farms, and businesses primarily in the rural areas of all 99 counties. Two types of electric cooperatives operate in Iowa: generation and transmission cooperatives (G&Ts) and distribution cooperatives. Distribution cooperatives purchase wholesale electricity from the G&T and distribute and sell this electricity to their members. Both the G&T and the distribution cooperatives are governed through a local board of directors elected by their members. Both types of RECs set their rates through the local governance process. The IUB sets the safety and service regulations that apply to the RECs. RECs securing any capital needs from the Rural Utility Service (RUS—formerly REA) are subject to RUS regulations at the federal level. If a cooperative is no longer under RUS jurisdiction, then a cooperative becomes FERC jurisdictional for its transmission tariffs and for wholesale transactions. Appendix A to this report provides a complete list of distribution cooperatives serving Iowa customers and the G&Ts serving those distribution cooperatives.

Iowa has 137 communities that operate electric utilities as a function of local government. Iowa has more municipal electric utilities than any other state, many of which have been in continuous operation for over 100 years. Municipal utilities are locally regulated through city councils or through boards of trustees appointed by the mayor and approved by the city council. All municipal utilities operate distribution systems that serve the local community and, in some cases, portions of outlying rural areas. Eighty-nine municipal utilities own and operate generating facilities that supply most or all of their energy needs. Muscatine, Ames, and Pella produce all or most of their electricity at local coal- or gas-fueled units. Forty municipal utilities are joint-owners of generating plants operated by other utilities. Seventy-three municipal utilities own backup or peaking generation and purchase their primary power supplies from municipal joint action entities or from other wholesale suppliers. Eight municipals own wind turbines and 1 (Waverly) owns and operates a small hydro facility. Forty-five municipal utilities purchase at least some of their power from the Western Area Power Administration (WAPA), the federal agency that operates hydroelectric facilities on the upper Missouri River Basin. Appendix B to this report provides a complete list of municipal electric utilities in Iowa.

Table 1-1 provides some basic statistics by type of utility for Iowa and the United States (U.S.). The rural nature of the territory served by Iowa's RECs is evident from these data.

Table 1-1 Basic Statistics by Type of Utility Company

	% of 1998 Electric MWh Sales		% of Miles of Distribution Line (1998)		Consumers Per Mile of Distribution Line (1998)	
	Iowa	U.S.*	Iowa	U.S.	Iowa	U.S.
Investor-Owned	76%	75%	42%	49%	25	35
REC	11%	9%	54%	43%	3	6
Municipal	13%	15%	4%	8%	NR	39

Note: * The remaining one-percent is supplied by federally owned utilities. The data reflecting consumers per mile of distribution line for publicly owned utilities in Iowa was not considered reliable (NR) by the IAMU.
Sources: Electric Sales 1998, DOE/EIA-0540(98), October 1999, pp. 174-177 as compiled by IUB Staff; Remaining Data: 1998 Electrical World Directory as Compiled by the IAEC

1.1.2 Reliability Over Regional Grids and the Emergence of the Wholesale Electric Market

The modern electric power industry is characterized by an interconnected grid of high voltage lines (referred to as transmission lines) over which utility generating units are economically dispatched. Economic dispatch refers to bringing on-line generating units within a service or control area on a least-cost basis until all demand is served.[2] The control area operator determines the dispatch order by fuel costs, unit efficiency, and variable operation and maintenance costs. On a real-time basis, the control area operator is the entity ultimately responsible for ensuring reliability within its control area through the dispatch of generating units and transmission facilities. The regional interaction of generating units, transmission facilities, and control area operators comprise the bulk power system.

The North American Electric Reliability Council (NERC) has the primary responsibility for establishing and encouraging compliance with reliability guidelines for the bulk power system. NERC defines reliability as “the degree to which the performance of the elements of [an electrical] system results in power being delivered to consumers within accepted standards and in the amount desired.” NERC’s definition encompasses what the industry refers to as adequacy and security. Adequacy relates to long-term planning which requires sufficient generating and transmission resources to meet projected demand in the region. Security implies that the system will continue to operate even after generating plant or transmission outages occur. NERC is comprised of regional reliability councils. Although the regional reliability councils follow NERC’s guidelines, they often have different reliability requirements and enforcement measures.

The North American bulk power system includes three major transmission interconnections: ERCOT (which encompasses a large part of Texas), the Western Interconnect (which includes the western states), and the Eastern Interconnect (which includes the midwest, south, east, and parts of Canada). Within the major interconnections are regional reliability councils and control areas. Figure 1-2 shows the locations of the three major transmission interconnections and the 10 regional reliability councils. Theoretically, power can flow from any point within the interconnection to any other point within the interconnection. Practically, power can only flow to a very limited degree between the interconnections.

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[2] Exceptions to economic dispatch may be made as a result of transmission constraints, requirements for generation for voltage support, and differences in cost methodologies.

Figure 1-2

HYDRO QUEBEC
30GW
1 Control Area

Eastern
470 GW
103 Control Areas

WSCC
120 GW
33 Control Areas

ERCOT
47 GW
9 Control Areas

Until recently, most of Iowa's major utilities have been part of MAPP's regional reliability council. MAPP (which refers to the Mid-Continent Area Power Pool) is a voluntary association of electric utility stakeholders who do business in the upper midwest.[3] Reliability in the MAPP region is maintained by members adhering to planning and operating rules that were developed by MAPP members and by NERC. For example, MAPP enforces reliability by requiring its member utilities to do reserve planning and by assessing after-the-fact penalties to member utilities failing to meet reserve requirements. Each utility's generating capacity, adjusted for power purchases and sales, for each month, must be equal to or more than its peak demand plus a 15 percent reserve margin. Each utility is also required to provide sufficient transmission capacity to serve its load without relying on or without imposing an undue burden on other systems. To minimize the effects of the sudden loss of a generating unit or transmission line, MAPP

[3] MAPP provides many functions. It is a power pool, regional reliability council, regional security coordinator, regional transmission group, and a power and energy market. In addition, it maintains an open access OASIS node.

utilities are required to maintain operating reserves. The operating reserve for the MAPP system is the amount of generation sufficient to cover the loss of the largest generation or transmission resource in the region. Utilities are allocated their share of operating reserves based on their peak demand.

In May 2000, Alliant-West left MAPP's regional reliability council and joined MAIN's reliability council. MAIN refers to the Mid-American Interconnected Network. As part of the agreement reached with MAPP, Alliant-West will maintain its operating reserves for the benefit of MAPP members until May 2001. All other reliability functions have been transferred to MAIN. MAPP and MAIN also have plans to merge their reliability functions by the end of 2001 and form a new, larger reliability region.

The merging of MAPP's and MAIN's reliability functions is one result of the many changes occurring in the electric utility industry since the passage of the Energy Policy Act in 1992 (EPACT). The EPACT opened the door to competition in the wholesale electricity markets by authorizing non-utility generators to build and operate power plants and requiring the FERC to ensure nondiscriminatory, open access to utility transmission systems.

In response to the EPACT, the FERC issued Order 888 in April 1996, requiring IOUs to file tariffs for open-access transmission. Order 888 also encouraged utilities to form and join independent system operators (ISOs) to operate regional transmission systems and be independent of all market participants. Within the last few years, several ISOs that own neither generation nor transmission have taken over regional transmission functions in California, New England, New York, and the mid-Atlantic (PJM) region.

Regional Transmission Organizations (RTOs) were the next step in the ISO evolution. In December 1999, FERC issued Order No. 2000 on RTOs requiring IOUs to file with FERC, by October 2000, proposals for joining a RTO or an explanation of why the utility cannot join such a regional organization. Alliant Energy is a transmission owning member of the Midwest Independent System Operation (MISO). The MISO intends to meet all of the requirements to become an RTO in the timeframe outlined by FERC.

With all the legislative and regulatory changes occurring over the last several years, it is not surprising that the transmission system is being used for purposes for which it was not designed. The system was designed to connect an individual utility's generating units to its customer load centers and to interconnect with its neighbor utilities. The transmission system is now being used to promote a competitive wholesale market that is fueled by 700 FERC-approved power marketers.[4]

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[4] Eric Hirst, Ph.D., Electric Reliability: Potential Problems and Possible Solutions, May 2000.

While the wholesale market in electricity is increasingly becoming open to competition, many retail markets are not (including Iowa's retail market). This raises issues of jurisdiction over transmission pricing. In states that have not opened their markets, retail rates continue to be set on a bundled basis. Bundled rates include the costs of generation, transmission, distribution, and customer services. At the time a state opens its retail markets, rates are unbundled and FERC assumes jurisdiction over transmission pricing. The state regulatory commission continues to price distribution service for IOUs. As such, unbundling requires the jurisdictional separation of transmission and distribution facilities. Transmission lines are typically high voltage lines that deliver electricity between generating plants or to wholesale customers. Distribution lines are typically low-voltage lines that connect the transmission system to the ultimate customer.

The FERC, in Order 888, established a seven-factor test as a guide for making this jurisdictional delineation. FERC gave the state commissions deference in applying the seven-factor test. On November 12, 1998, MidAmerican filed with the IUB a "Petition for Order Recommending Delineation of Transmission and Local Distribution Facilities," which was later approved by the IUB. On July 30, 1999, MidAmerican filed its proposed delineation with FERC. On February 4, 2000, the FERC issued an order approving the delineation. In accordance with these filings, MidAmerican's lines at 69kV and below and approximately 11 percent of MidAmerican's 161 kV lines are determined to have local distribution characteristics in accordance with the test of FERC's seven factors for local distribution. Alliant-West has not filed with either the IUB or FERC for transmission/distribution delineation using the seven-factor test.

1.2 Organization of the Report

As with any product or service, the provision of electricity involves the interaction of supply and demand. Consumers demand electricity and Iowa's electric utilities supply it. Section 2.0 of this report provides information on the supply and demand for electricity and the various elements that comprise both. The need to generate electricity coincident with its consumption, coupled with the extensive time and capital required to build new electricity infrastructure, makes it necessary to plan for adequate supply to meet forecasted demand. Subsection 2.1 provides historical and forecasted data on the adequacy of supply for MAPP utilities serving Iowa and Alliant-West. Subsection 2.2 details the unique aspects of electricity demand including customer load characteristics. An important distinction must be made between electric load and energy requirements. Electric load refers to customer demand at the time of the utility's peak demand. Since utility systems are designed and built to serve peak load, this factor is an essential element in future capacity planning. Energy requirements reflect customer consumption of kilowatt-hours (kWhs) in a given year. Demand-side management programs affect both peak load and energy requirements. Subsection 2.2.3 discusses utility demand-side management programs including program descriptions, results, and expenditures. Subsection 2.3 details electric supply by characterizing Iowa's major generating units by historical fuel use, efficiency, and diversity, in addition to cost per kWh of energy produced.

Subsection 2.3.2 looks at another major source of supply for Iowa's utility companies – purchased power. Data are provided on historical power purchases from alternate energy sources and historical and future purchases from conventional generating sources. In addition, this subsection discusses the spot market for wholesale supply that was essentially created through FERC Order 888. Subsection 2.3 concludes with information regarding regional supply considerations, air emissions from conventional generating sources (primarily coal, oil, and natural gas), and a brief description of the requirements that must be met before a new generating plant is built in Iowa.

The delivery of electricity to the ultimate customer is accomplished through both transmission and distribution lines. Section 3.0 of the report looks at Iowa's delivery system including the location of vital infrastructure, the age and condition of the state's transmission and distribution infrastructure, and the historical reliability of the regional delivery systems. The section concludes with a discussion of future changes to the transmission and distribution system, as well as a description of the state's transmission siting requirements.

Section 4.0 provides a brief description of how customer service systems have changed over the last few years. Customer service includes metering, billing, and customer contact.

1.3 Limitations of the Report

While it is understood customers are concerned with both the reliability and cost of their electric supply, the data in this report concentrate more on the reliability of electric supply and the characteristics comprising electric demand. As such, utility rates are not compiled and reported. In addition, the report does not attempt to assess, evaluate, or analyze the data provided.

2.0 ELECTRIC LOAD AND SUPPLY CONDITIONS

The use of electricity places “load” on an electric utility system. Load is measured in kilowatts (kW or 1,000 watts), megawatts (MW or 1,000 kW) or gigawatts (GW or 1,000 MW). Electric load varies depending on the number and size of devices using electricity at a given time. When the sum of individual loads reaches a maximum level, the utility experiences system "peak load." In Iowa, most peak loads occur during hot summer days when air conditioning use reaches maximum levels. A utility’s “capability” for meeting its peak load is based on its electric generating capacity, either owned or available through purchase.

Section 2.1 compares historical and projected load for Iowa utilities and the adequacy of available supply to meet that load. Section 2.2 details electric demand including load and energy requirements. Section 2.1 details the various elements of electric supply.

2.1 Adequacy of Supply in Meeting Current and Projected Load Requirements

This subsection compares Iowa peak loads and capabilities, both historic and forecasted, based on data reported by Iowa utilities to MAPP and data reported by Alliant-West. Most large Iowa utilities are (or have recently been) MAPP members. MAPP member utilities and Alliant-West account for the vast majority of Iowa’s electricity sales. Therefore, comparisons based on MAPP utilities and Alliant-West should provide a reasonably accurate representation of Iowa as a whole. Some MAPP utilities, principally MidAmerican and Alliant-West, also serve smaller areas in adjacent states. The comparisons in this section involve no adjustments to derive Iowa-only data from total system data. Since utilities plan on a system-wide rather than state-by-state basis, such adjustments would add little in meaning or accuracy to the results. Similarly, no adjustments are made to account for the diversity of different times each utility reaches its respective system peak.[5]

Figure 2-1 compares historic annual peak loads and capabilities for most Iowa MAPP utilities and Alliant-West.[6]

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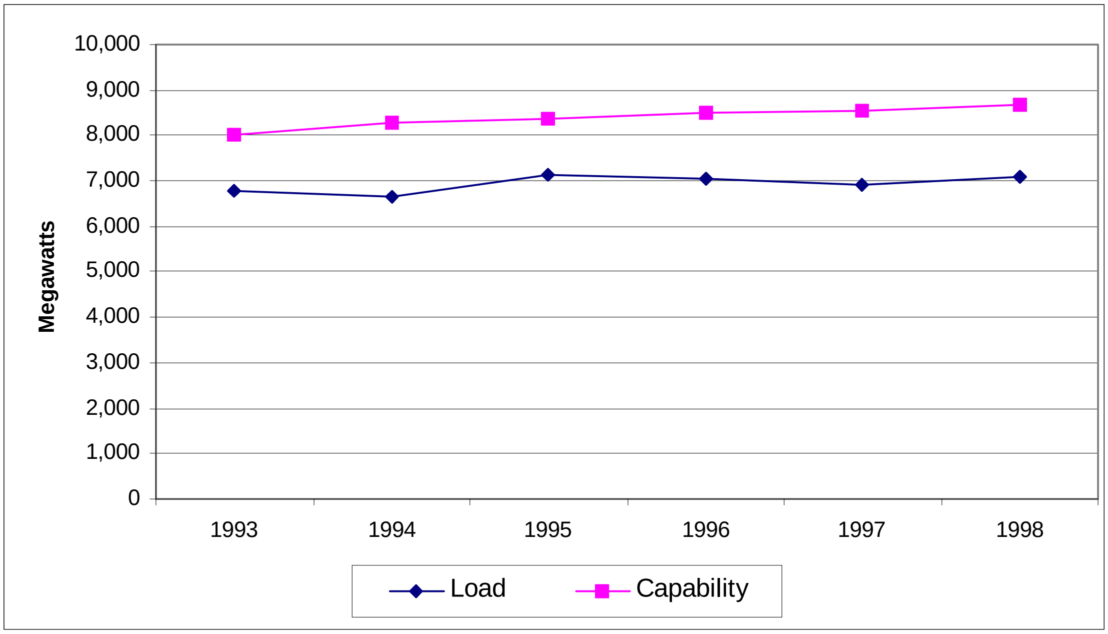
[5] Reporting utilities seem to regard such adjustments as minor. For example, MidAmerican has estimated the diversity adjustment within its control area at 1 percent or less, and Alliant estimates the diversity between its east and west systems at less than 1 percent.

[6] Appendix C provides a detailed list of utilities included in Figures 2-1 and 2-2.

Figure 2-1 Historic Load and Capability

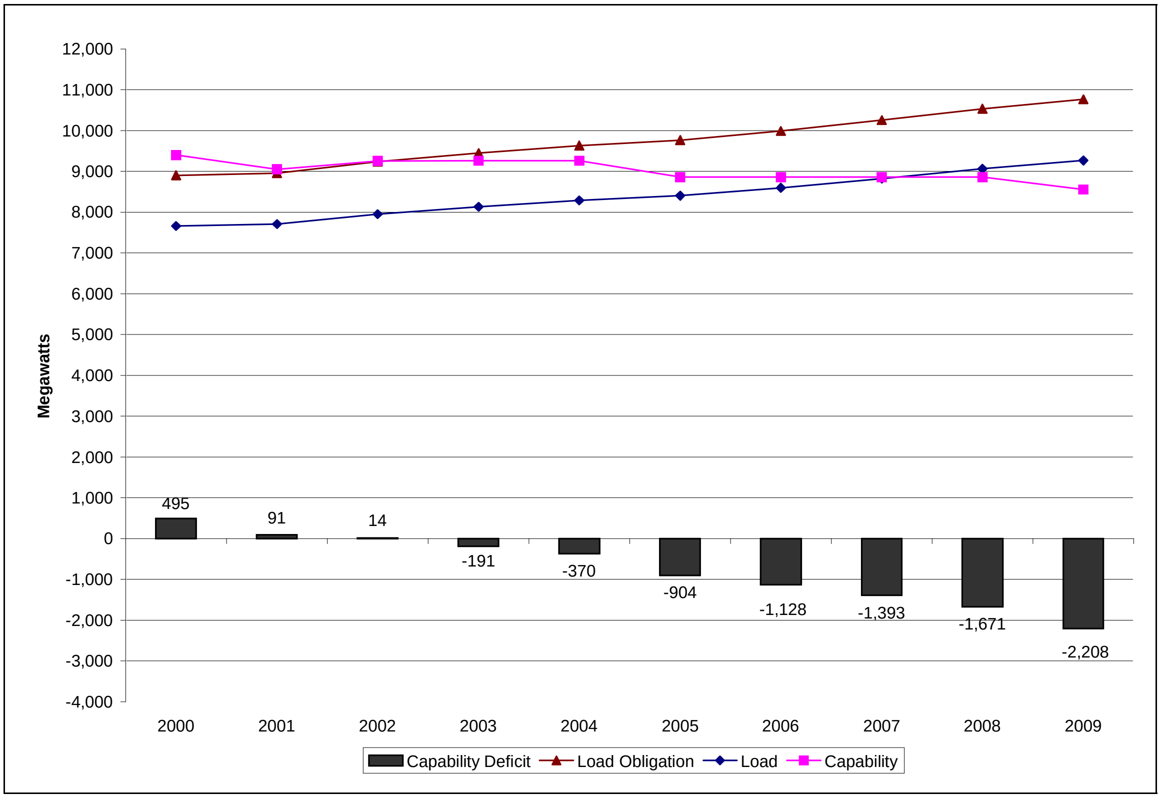


Notes: Load equals annual peak demand, plus firm power sales, less firm power purchases. Capability equals net generating capability, plus participation power purchases, less participation power sales.
Sources: Load data: compiled by MidAmerican Energy and Alliant Energy, supplemented with data from *Annual Electric Utility Report* (EIA-861), Energy Information Administration, 1992-1999; Capability data: *MAPP Load and Capability Report*, April 1990-1999.

Figure 2-2 compares forecasted annual peak loads and capabilities for Iowa MAPP utilities and Alliant-West.[7] The line labeled "load obligation" represents annual load plus a 15 percent reserve margin. The bars labeled "capacity deficit" reflect the difference between the annual load and the annual load obligation. The forecasts assume each planning area will continue serving customers in its service area with sufficient supply resources, either through owned-generation or purchased power contracts, to cover peak loads plus a 15 percent reserve margin.

[7] Loads from four municipal utilities were added to the forecasted data: Algona, Ames, Atlantic, Harlan, Muscatine, and Pella Municipals. The municipals add less than 1 percent to projected load obligations.

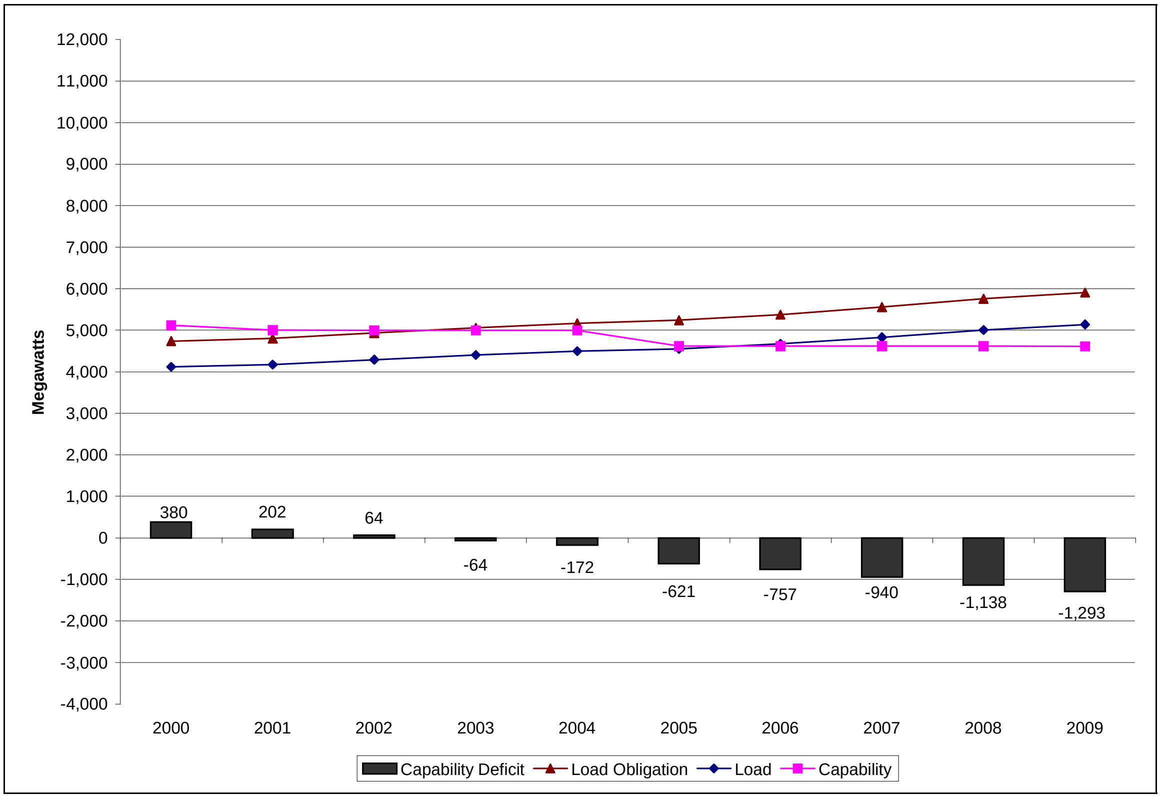
Figure 2-2 Forecasted Summer Net Load, Capability, Load Obligation, and Capability Surplus/Deficit(-)



Notes: "Net Load" is reduced for load management programs including direct load control and interruptible load. "Net Load" includes net firm power transactions. "Load Obligation" represents annual load plus a 15 percent reserve margin for MAPP utilities and annual load plus an 18 percent reserve margin for Alliant-West. "Capability" includes any committed generation and proposed generation. Committed units are under design, under construction, authorized for construction, or for which a construction license is pending. Proposed units are planned for installation but not authorized for construction.
Sources: The *MAPP Load and Capability Report*, May 1, 2000, for all utilities except the load and capability forecast for Alliant/CIPCO which was provided by Alliant.

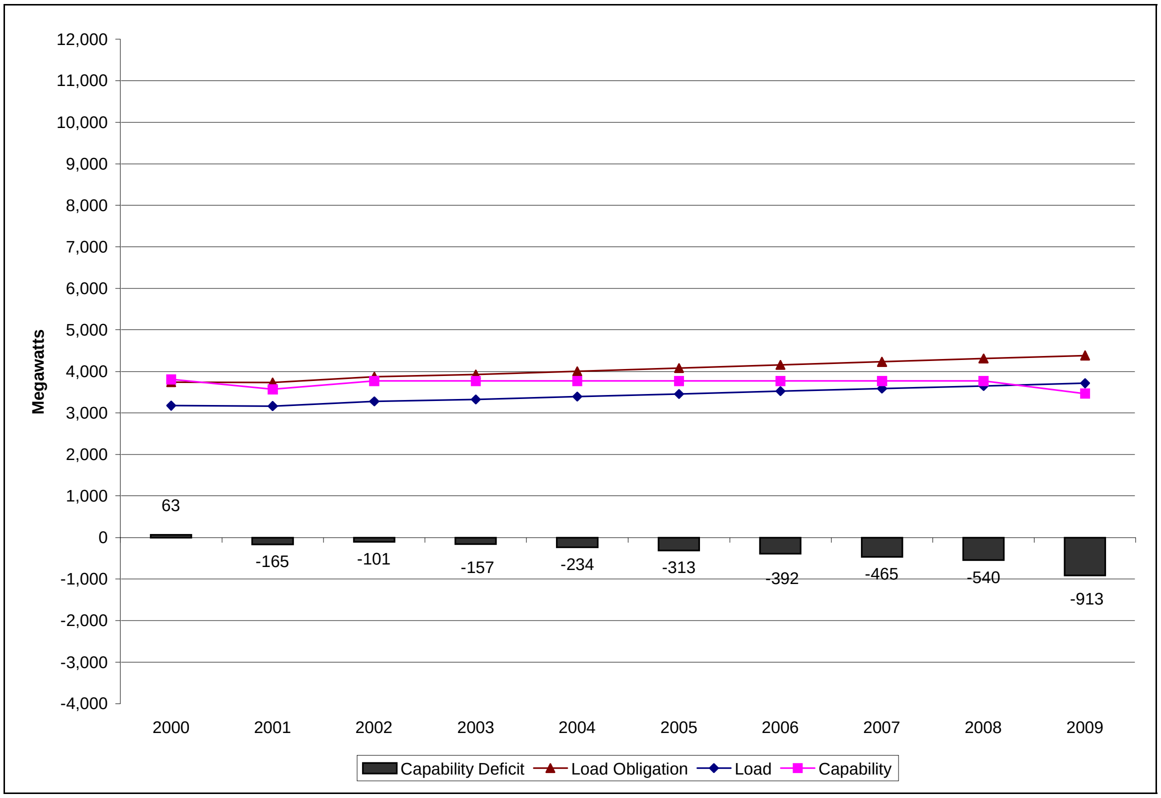
Figure 2.2 includes both MidAmerican's and Alliant-West's control areas, which comprise most of Iowa's load and capability. **Figures 2.3 and 2.4** illustrate these same data for MidAmerican's control area (using a 15 percent reserve requirement) and Alliant-West's control area (using an 18 percent reserve requirement). Alliant-West, as a member of MAIN, is required to maintain reserves equal to 17 to 20 percent of peak load. Alliant Energy has chosen to hold 18 percent reserves consistent with a Public Service Commission of Wisconsin requirement. MAPP uses a 15 percent reserve requirement.

Figure 2-3 Forecasted Summer Load, Capability, Load Obligation, and Capability Surplus/Deficit(-) for MidAmerican Control Area



Notes: See Figure 2-2.
Sources: See Figure 2-2.

Figure 2-4 Forecasted Summer Load, Capability, Load Obligation, and Capability Surplus/Deficit(-) for Alliant-West (MAIN Forecast) and CIPCO



Notes: See Figure 2-2.
Sources: See Figure 2-2.

2.2 Electric Demand

2.2.1 Electric Load and Energy Requirements

Electric load refers to customer demand at the time of the utility's peak demand, expressed in thousands of kW, or MW. In Iowa, peak load generally occurs in the summer. **Table 2-1** provides summer peak load forecasts over the next ten years (2000-2009) for Iowa MAPP utilities and Alliant-West.

Table 2-1 Forecast of Summer Peak Load Requirements for Iowa MAPP Utilities and Alliant-West (MW = 1,000 kW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total Growth 2000-2009	Average Annual Growth 2000-09
Alliant/CIPCO	3,149	3,244	3,283	3,331	3,397	3,464	3,531	3,593	3,656	3,718	569	63
Algona	24	24	25	26	26	27	28	29	29	30	6	1
Ames	114	115	117	119	120	122	124	126	127	129	15	2
Atlantic	27	28	29	30	31	32	33	34	35	36	9	1
Harlan	15	16	16	16	16	16	16	16	16	16	1	0
MidAmerican	4,142	4,193	4,309	4,420	4,514	4,575	4,693	4,852	5,024	5,156	1,014	113
Muscatine	145	147	150	153	155	158	160	163	165	168	23	3
Pella	44	45	46	47	48	49	51	52	53	54	10	1
Total MW	7,660	7,812	7,975	8,142	8,307	8,443	8,636	8,866	9,105	9,306	1,646	183
Percent Change	N/A	2.0%	2.1%	2.1%	2.0%	1.6%	2.3%	2.7%	2.7%	2.2%	21.5%	2.2%

Notes: MidAmerican includes the utilities within its control area. Both the MidAmerican and Alliant/CIPCO forecasts assume all load management resources are implemented.
Sources: The *MAPP Load and Capability Report*, May 1, 2000 for all utilities, except the load and capability forecast for Alliant-West which was provided by Alliant-West.

These peak load forecasts are used to derive the Capability Surplus/Deficits in **Figure 2-2** above. **Table 2-2** summarizes historical summer peak loads for MidAmerican Energy and Alliant-West (1993-1998).

Table 2-2 Historical Summer Peak Load Requirements for MidAmerican Energy and Alliant-West Control Areas (MW = 1,000 kW)

	1993	1994	1995	1996	1997	1998	1999	Total Growth 1993-1999	Average Annual Growth 1993-99
Total MW	6,600	6,629	7,078	7,133	7,096	7,298	7,639	1,039	173
Percent Change	N/A	0.4%	6.8%	0.8%	-0.5%	2.9%	4.7%	15.7%	2.5%

Notes: Utilities include: Alliant-West (including CIPCO), and MidAmerican Energy (including the utilities within its control area).
Sources: MEC: MEC file "mec peaks & req1.xls," 8/9/00 (EIA-861); ALT-W: revised Table 1.1.2.1a “Annual Booked Peak Demand at the Firm Peak Hour,” 8/8/00.

Energy requirements refer to customers’ kWh usage over the course of a year. Because of the large numbers involved, energy requirements are expressed in millions of kWhs, or GWh. **Table 2-3** provides utilities' forecasted energy requirements over the next ten years (2000-2009) and **Table 2-4** summarizes historical annual energy requirements for MidAmerican Energy and Alliant-West (1993-1998).

Table 2-3 Forecast of Annual Energy Requirements for Iowa MAPP Utilities and Alliant-West (GWh= 1,000,000 kWh)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total Growth 2000-2009	Average Annual Growth 2000-09
Alliant-West	17,065	17,305	17,444	17,726	18,060	18,398	18,744	19,079	19,045	19,726	2,661	296
CIPCO	2,610	2,762	2,823	2,857	2,899	2,930	2,960	2,990	3,017	3,046	436	48
Algona	96	99	103	106	107	110	114	117	119	122	26	3
Ames	485	497	509	521	533	545	557	569	581	593	108	12
Atlantic	111	112	113	119	124	125	131	134	140	143	32	4
Harlan	62	62	64	65	65	66	68	68	68	68	6	1
MidAmerican	19,890	20,153	20,504	20,896	21,308	21,730	22,149	22,572	23,003	23,445	3,555	395
Muscatine	931	949	968	988	1,008	1,027	1,049	1,068	1,086	1,109	178	20
Pella	182	183	191	194	195	201	206	208	215	219	37	4
Total GWh	41,432	42,122	42,719	43,472	44,299	45,132	45,978	46,805	47,634	48,471	7,039	783
Percent Change	N/A	1.7%	1.4%	1.8%	1.9%	1.9%	1.9%	1.8%	1.8%	1.8%	17.0%	1.8%

Notes: MidAmerican includes the utilities within its control area.
Sources: Report by IOUs, August 12, 2000, Table 1.1.1.3 "Forecasts of Annual Energy"; Alliant-West and CIPCO are from the most recent internal MAIN Load & Capability calculations; all other information is from the most recent MAPP Form 3 filings.

Table 2-4 Historical Annual Energy Requirements for MidAmerican Energy and Alliant-West Control Areas (GWh = 1,000,000 kWh)

	1993	1994	1995	1996	1997	1998	1999	Total Growth 1993-1999	Average Annual Growth 1993-99
Total GWh	32,837	34,196	35,602	36,311	37,087	38,847	39,030	6,194	1,032
Percent Change	N/A	4.1%	4.1%	2.0%	2.1%	4.7%	0.5%	18.9%	2.9%

Notes: Utilities include: Alliant-West (including CIPCO), and MidAmerican Energy (including the utilities within its control area).
Sources: MEC: MEC file "mec peaks & req1.xls," 8/9/00 (PowerDat 7/00); ALT-W: revised Table 1.1.2.1g "Actual Annual Energy Requirements," 8/8/00 (MAPP Form 3 filings 1990-1998, MAIN filing for 1999 and internal records).

2.2.1.1 Cooperative Load and Energy Requirements

MAPP forecasts and historical data include most Iowa cooperative load and energy requirements. The purpose of this subsection is to separately set forth all load and energy requirements for Iowa cooperatives, including the MAPP member cooperatives represented in **Tables 2-1** through **2-4** above. **Table 2-5** provides peak load and energy requirements forecasts for the G&T cooperatives serving Iowa. Because some cooperatives are winter-peaking, both summer and winter peak load forecasts are included. **Table 2-6** summarizes G&T historical peak loads and energy requirements.

Table 2-5 Forecast of Peak Load and Annual Energy Requirements for Iowa Cooperatives (MW = 1,000 kW; GWh = 1,000,000 kWh)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total Growth 2000-2008	Average Annual Growth 2000-08
Summer MW Peak Loads	952	990	1,003	1,019	1,034	1,044	1,055	1,067	1,080	128	16
Percent Change	N/A	4.0%	1.3%	1.6%	1.5%	1.0%	1.1%	1.1%	1.2%	13.4%	1.6%
Winter MW Peak Loads	954	963	993	1,006	1,016	1,025	1,032	1,043	1,051	97	12
Percent Change	N/A	0.9%	3.1%	1.3%	1.0%	0.9%	0.7%	1.1%	0.8%	10.2%	1.2%
GWh Energy	5,539	5,717	5,818	5,885	5,943	5,998	6,053	6,121	6,185	646	81
Percent Change	N/A	3.2%	1.8%	1.2%	1.0%	0.9%	0.9%	1.1%	1.0%	11.7%	1.4%

Notes: The total data include data for the Iowa distribution RECs associated with the following G&Ts: Central Iowa Power Cooperative (includes SIMECA) with diversity, Corn Belt Power Cooperative (excludes NIMECA but includes Webster City and Estherville), Dairyland Power Cooperative, L&O Power Cooperative, Northeast Missouri Electric Power Cooperative, and Northwest Iowa Power Cooperative (includes SIMECA). The data for cooperatives serving more than Iowa were assigned or allocated to the applicable Iowa cooperatives.
Sources: Compiled by the IAEC.

Table 2-6 Historical Peak Load and Annual Energy Requirements for Iowa Cooperatives (MW = 1,000 kW; GWh = 1,000,000 kWh)

	1995	1996	1997	1998	1999	Total Growth 1995-1999	Average Annual Growth 1995-99
MW Peak Loads	855	888	916	958	997	142	36
Percent Change	N/A	3.9%	3.2%	4.6%	4.1%	16.6%	3.9%
GWh Energy	4,149	4,382	4,603	5,138	5,333	1,184	296
Percent Change	N/A	5.6%	5.0%	11.6%	3.8%	28.5%	6.5%

Notes: The total data include data for the Iowa distribution rural electric cooperatives associated with the following G&Ts: Central Iowa Power Cooperative (includes SIMECA) with diversity, Corn Belt Power Cooperative (excludes NIMECA but includes Webster City and Estherville), Dairyland Power Cooperative, L&O Power Cooperative, Northeast Missouri Electric Power Cooperative and Northwest Iowa Power Cooperative (includes SIMECA). The data for cooperatives serving more than Iowa were assigned or allocated to the applicable Iowa cooperatives.
Sources: Compiled by the IAEC.

2.2.1.2 Municipal Utility Load and Energy Requirements

The purpose of this subsection is to separately set forth all electric load and energy requirements for Iowa municipal utilities, including MAPP member load and energy requirements represented in **Tables 2-1** through **2-4** above. **Table 2-7** summarizes total historical peak load and annual energy requirements for Iowa municipal utilities, for the period 1993-1998.

Table 2-7 Historical Peak Load and Annual Energy Requirements for Iowa Municipal Utilities (MW = 1,000 kW; GWh = 1,000,000 kWh)

	1993	1994	1995	1996	1997	1998	Total Growth 1993-1998	Average Annual Growth 1993-98
MW Peak Loads	928	937	1,041	1,002	1,016	1,066	138	28
Percent Change	N/A	0.9%	11.2%	-3.7%	1.3%	4.9%	14.9%	2.8%
GWh Energy	4,051	3,898	4,298	4,385	4,531	4,714	634	127
Percent Change	N/A	-3.8%	10.2%	2.0%	3.3%	4.0%	15.7%	3.0%

Notes: The totals are summations of data for individual municipal utilities and are not adjusted for diversity.
Sources: EIA 861 reports for Iowa municipal utilities as compiled by the IAMU.

2.2.2 Electric Load and Customer Characteristics

Electric load is evaluated in several different ways. For example, the concept of "load factor" indicates the degree to which generating capacity is being utilized by comparing annual energy requirements, or average load, with peak load.[8] As a measure of utilization, load factor is expressed as a percentage. **Table 2-8** summarizes historical Iowa load factors by type of utility, compared to average load factors for the United States as a whole. Year-to-year variations may suggest sensitivity to weather conditions.

[8] Load factor may be computed by: 1) deriving average load by dividing annual energy requirements by the number of hours in the year (typically 8,760 hours); and 2) dividing this result by peak load.

Table 2-8 Historical Iowa Electric Load Factors

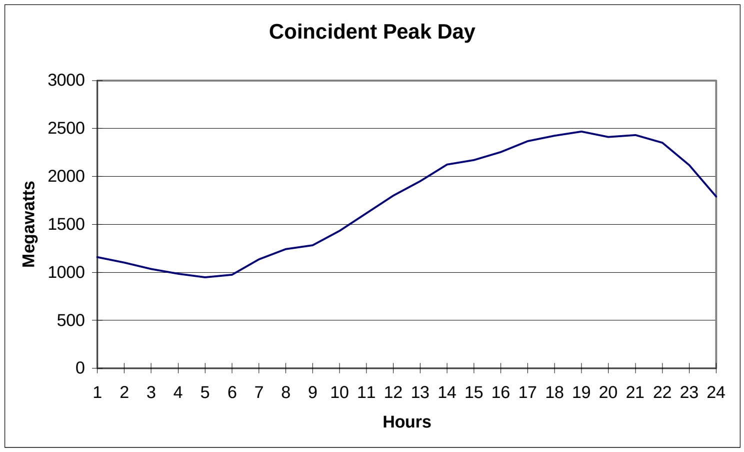
	1995	1996	1997	1998	Average 1995-98
Alliant-West	66.9%	66.0%	68.3%	70.4%	67.9%
MidAmerican	52.6%	55.7%	56.8%	57.1%	55.5%
Municipals	49.0%	51.8%	53.1%	52.6%	52.3%
RECs	55.4%	56.2%	57.4%	61.2%	57.6%
U.S. Average	55.4%	57.2%	54.3%	55.3%	55.5%

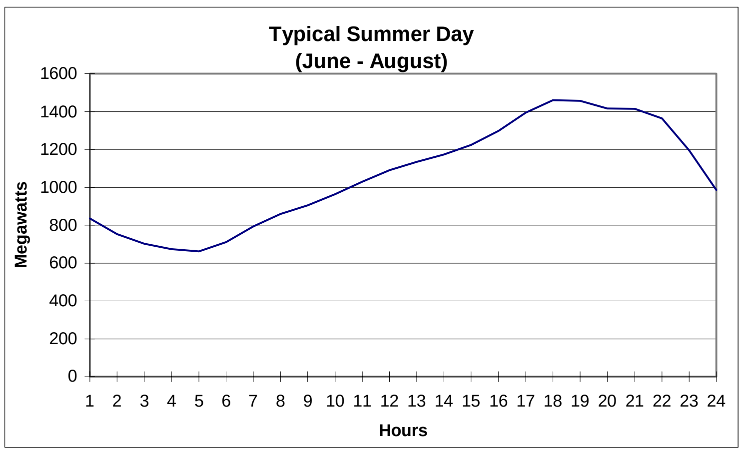
Notes: Data for Alliant-West and MidAmerican are for the companies only, not their control areas. Complete 1999 data are available for Alliant-West only. RECs' data, according to the IAEC, include Municipal Electric Cooperative Association (MECA) members. MECA members are not removed from the Municipals data because, according to the IAEC, they are not full requirements customers of the G&T cooperatives that serve them. The impact on the results is minor.
Sources: Alliant-West data: MAPP Form 3 filings and internal company data, compiled by Alliant; MidAmerican data: internal company RDI PowerDat data, compiled by MidAmerican; Municipals data: EIA 861 reports for Iowa municipal utilities, compiled by the IAMU; RECs data: annual load summaries for G&T cooperatives serving Iowa, compiled by the IAEC; U.S. Average data: *Electric Power Annual*, 1998, Vol. 2, Energy Information Administration, Tables 33 and 35, pp. 58-60, compiled by IUB Staff.

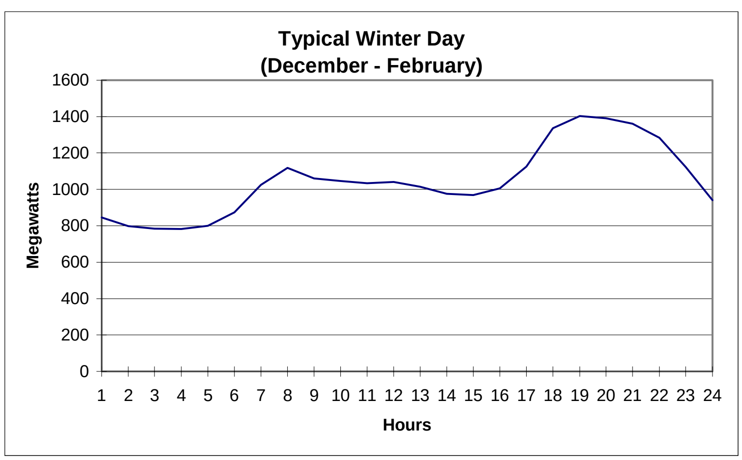
Load may also be evaluated on a seasonal or time-of-day basis. **Figures 2-5** through **2-8** each present hourly load profiles for three selected 24-hour periods: 1) the day of coincident peak;[9] 2) a typical summer day (June – August); and 3) a typical winter day (December – February). **Figure 2-5** presents the three load profiles for residential customers, **Figure 2-6** for commercial customers, **Figure 2-7** for industrial customers, and **Figure 2-8** for the customer classes combined.

[9] Coincident peak day is the day in which utility systems experience peak load. That is, it reflects addition of the hourly loads on the annual system peak day for each of the respective utilities. This may not be the same day for each utility.

Figure 2-5 Residential Class Hourly Load Profiles for Iowa Investor-Owned Utilities

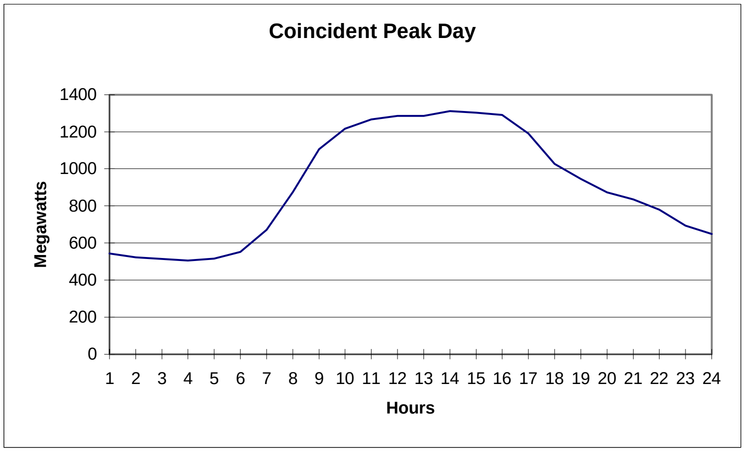


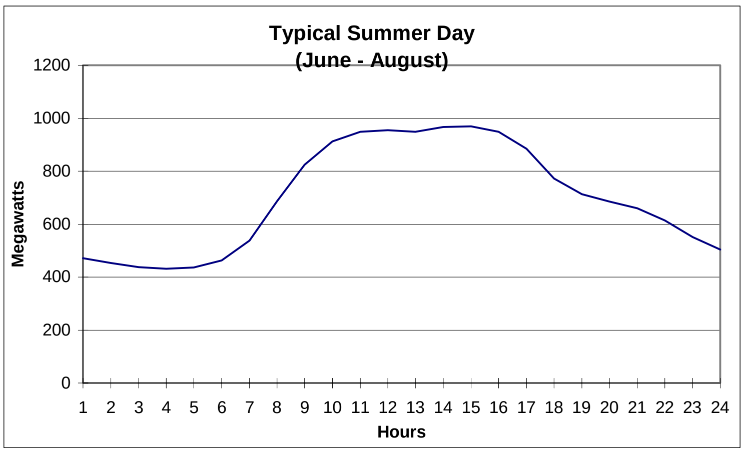


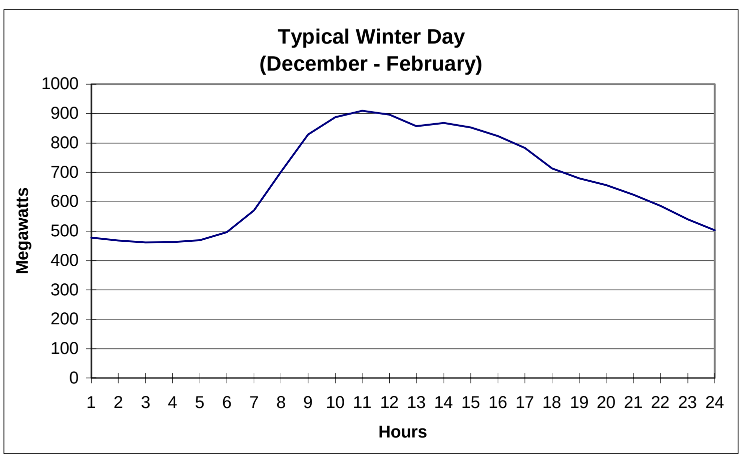


Sources: 1996 hourly class load data filed by Alliant and MidAmerican under 199 IAC 35.9(2) for the residential class.

Figure 2-6 Commercial Class Hourly Load Profiles for Iowa Investor-Owned Utilities

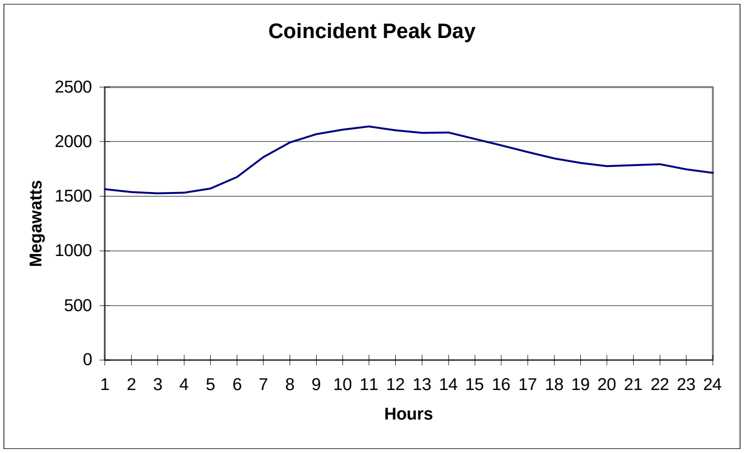


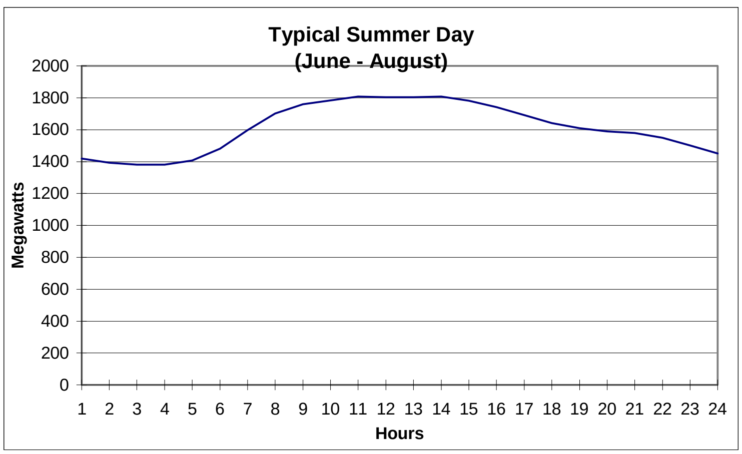


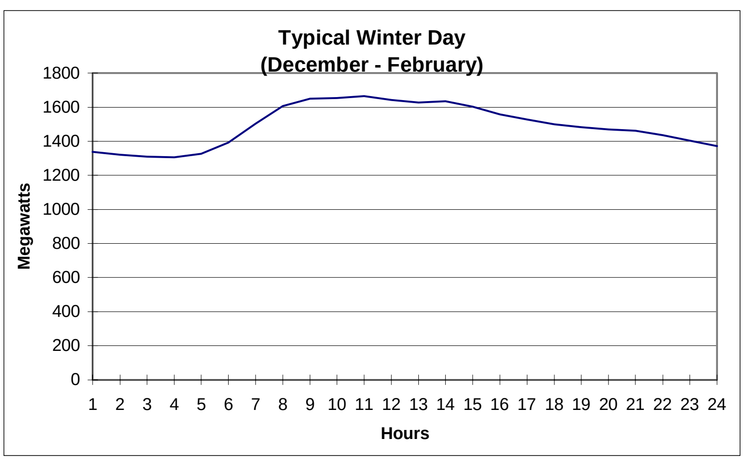


Sources: 1996 hourly class load data filed by Alliant and MidAmerican under 199 IAC 35.9(2) for the commercial class.

Figure 2-7 Industrial Class Hourly Load Profiles for Iowa Investor-Owned Utilities

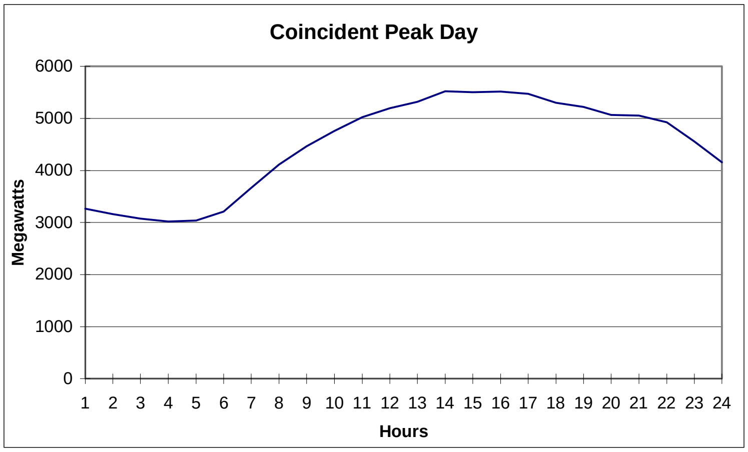


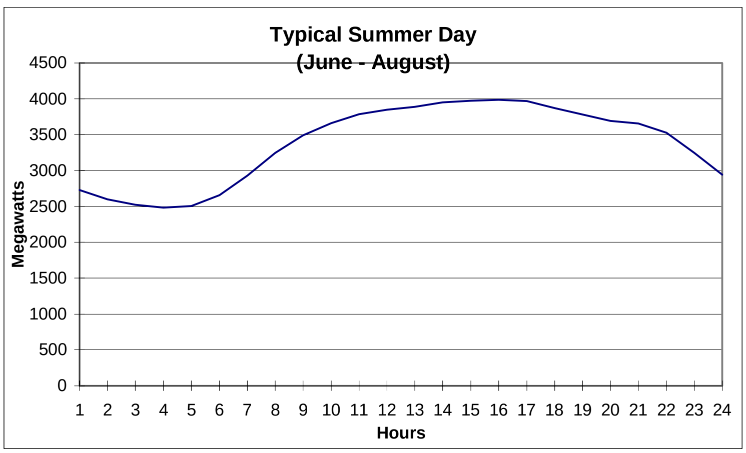


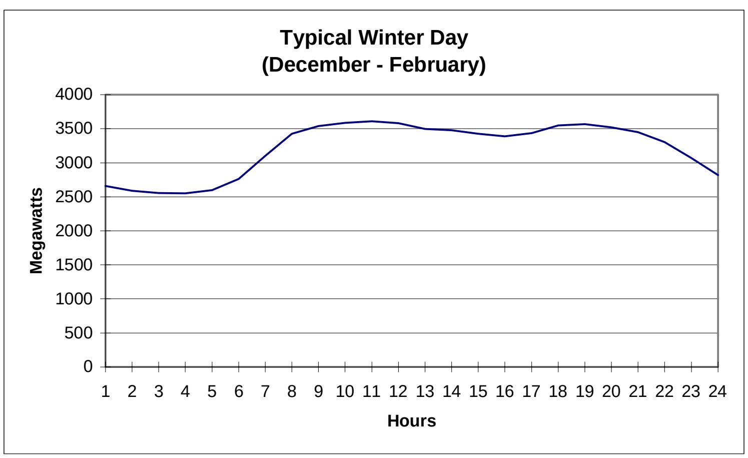


Sources: 1996 hourly class load data filed by Alliant and MidAmerican under 199 IAC 35.9(2) for the industrial class.

Figure 2-8 Total Customer Class Hourly Load Profiles for Iowa Investor-Owned Utilities







<u>Sources</u>: 1996 hourly class load data filed by Alliant and MidAmerican under 199 IAC 35.9(2) for the residential, commercial, and industrial classes combined.

Load and energy requirements can also vary by geographic area. **Table 2-9** shows differences in historical electric sales for the largest Iowa metropolitan areas served by IOUs (Alliant-West and MidAmerican) and by municipal utilities.

Table 2-9 Iowa Historical Electric Sales by Metropolitan Area and for the State As a Whole (GWH = 1,000,000 kWh)

Metropolitan Area	Serving Utility	1995 GWH	1996 GWH	1997 GWH	1998 GWH	1999 GWH	Average Annual Growth 1995-98	Average Annual Growth 1995-99
Cedar Rapids	Alliant	2,268	2,479	2,690	2,767	2,801	6.9%	5.4%
Council Bluffs	MidAm	541	596	595	620	621	4.6%	3.5%
Davenport	MidAm	1,719	1,722	1,762	1,730	1,993	0.2%	3.8%
Des Moines	MidAm	4,010	4,083	4,185	4,302	4,435	2.4%	2.6%
Dubuque	Alliant	981	960	982	992	981	0.4%	0.0%
Iowa City	MidAm	779	785	789	809	924	1.3%	4.4%
Sioux City	MidAm	910	917	938	963	974	1.9%	1.7%
Waterloo	MidAm	1,236	1,222	1,240	1,340	1,254	2.7%	0.4%
Ames	Muni	386	412	473	502	N/A	9.2%	N/A
Cedar Falls	Muni	330	330	339	351	N/A	2.0%	N/A
Denison	Muni	122	123	129	133	N/A	2.9%	N/A
Muscatine	Muni	819	841	856	889	N/A	2.8%	N/A
Pella	Muni	146	154	161	170	N/A	5.3%	N/A
Spencer	Muni	127	131	135	134	N/A	1.9%	N/A
Waverly	Muni	99	104	107	112	N/A	4.3%	N/A
Webster City	Muni	119	123	124	134	N/A	3.9%	N/A
State of Iowa	All	34,301	34,999	36,148	37,318	N/A	2.8%	N/A

Sources: Alliant-West data: compiled by Alliant; MidAmerican data: compiled by MidAmerican; Municipal data: EIA 861 reports for Iowa municipal utilities, compiled by the IAMU; State of Iowa data: *Electric Power Annual*, 1995-98, Energy Information Administration, compiled by IUB Staff.

2.2.3 Energy Efficiency and Load Management

2.2.3.1 Program Descriptions and Discussion

Iowa Code Sections 476.6(17) and 476.6(19) authorize a variety of initiatives intended to improve the energy efficiency of Iowa homes and businesses. Energy Efficiency Programs now being implemented by IOUs include:

- Energy savings or **Energy Efficiency programs** save annual use of energy (kWh) and reduce peak load (kW). Examples include: 1) residential programs providing rebates and loans for home insulation, high efficiency furnaces, air conditioners, and other appliances; and 2) nonresidential programs providing rebates for commercial lighting, heating, cooling and refrigeration, or high-efficiency industrial motors and improvements to manufacturing processes.

- **Low-Income programs** target low-income customers for weatherization and other energy efficiency measures.

- **Tree Planting programs** provide assistance to customers and communities to plant and care for trees.

- **Load management programs** provide incentives to customers to change their patterns of energy use, shifting load away from expensive peak periods. Typical programs include: 1) direct control of air conditioners; 2) discounts for industrial customers willing to interrupt their usage during peak periods; and 3) time-of-use rates that shift peak period usage by pricing higher during peak periods and lower during off-peak periods.

- **Research and development programs** are carried out through the Iowa Energy Center and the Center for Global and Regional Environmental Research. These programs are funded by a surcharge on all utilities, including municipal utilities and RECs.

Load management by utilities is typically achieved through programs that offer customers lower rates or rebates for reducing the customer's use of electricity at a future point in time. The customer allows the utility to directly shut off part of the customer's load (direct load control) or agrees to reduce load by a certain amount (interruptible load) when the utility calls on the customer to do so, typically during peak load periods.

2.2.3.2 Energy Efficiency and Load Management Savings

Energy efficiency and load management have succeeded in reducing both load and energy requirements for Iowa electric utilities. **Tables 2-10** through **2-15** present cumulative MW load savings from both energy efficiency and load management programs for IOUs (**Tables 2-10** and **2-11**), RECs (**Tables 2-12** and **2-13**), and municipal utilities (**Tables 2-14** and **2-15**).

Table 2-10 Investor-Owned Utilities - MW Savings Due To Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cumulative MW Savings	3	9	19	37	63	93	123	142	159

Notes: The table above reflects only MW savings for energy efficiency. IOU source data included savings due to load management.
Sources: Report by IOUs, August 12, 2000, Tables 1.4.1.2.c and 1.4.1.2.d; IUB MW Data - IUB Staff Report of November 24, 1999.

Table 2-11 Investor-Owned Utilities - MW Savings Due To Load Management

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cumulative MW Savings	176	192	246	451	514	565	582	655	704

Notes: IOU data includes 99 MW of interruptible load for IES Utilities prior to the initiation of DSM programs. IOU data includes savings associated with all load management programs, including 1997-1999 curtailments for the former Iowa-Illinois Gas and Electric. A comparison with the data provided by IOUs for the IUB Report of November 24, 1999 shows approximately 175 MW of load management savings existing prior to 1990 and credited to Energy Efficiency through 1998. The comparison also shows additional IOU load management of 14 MW in 1997 and 47 MW in 1998.
Sources: Report by IOUs, August 12, 2000, Tables 1.4.1.2.c and 1.4.1.2.d; IUB MW Data - IUB Staff Report of November 24, 1999.

Table 2-12 Rural Electric Cooperatives - MW Savings Due to Voluntary Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cumulative MW Savings	12	17	26	35	15	17	14	17	18

Notes: In the IAEC report, MW savings were provided as one aggregate total. The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Data from the IAEC- EE Sum IAEC Jt. Filing Co-ops; Report of IUB Staff, November 24, 1999.

Table 2-13 Rural Electric Cooperatives - MW Savings Due to Voluntary Load Management

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cumulative MW Savings	10	10	0	0	19	20	46	48	50

Notes: In the IAEC report, MW savings were provided as one aggregate total. The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Report from the IAEC, August 7, 2000 - EE Sum IAEC Jt. Filing Co-ops; Report of IUB Staff, November 24, 1999.

Table 2-14 Municipal Utilities - MW Savings Due to Voluntary Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cumulative MW Savings	29	58	65	72	78	84	84	85	87

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Report of IUB Staff, November 24, 1999.

Table 2-15 Municipal Utilities - MW Savings Due to Voluntary Load Management

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cumulative MW Savings	16	32	56	80	111	147	162	179	190

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Report of IUB Staff, November 24, 1999.

Tables 2-16 through **2-18** present cumulative MWh energy savings for IOUs (**Table 2-16**), RECs (**Table 2-17**), and municipal utilities (**Table 2-18**).

Table 2-16 Investor-Owned Utilities - MWh Savings Due to Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Cumulative MWh Savings	6,821	31,172	66,386	145,805	258,202	390,799	499,586	592,874	654,607	696,039

Notes: Comparison of the total of the IOU tables with data provided for the IUB Staff Report of November 24, 1999 shows very good correspondence among the numbers. The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Report by IOUs, August 12, 2000, Tables 1.4.1.2.a and 1.4.1.2.b.

Table 2-17 Rural Electric Cooperatives - MWh Savings Due to Voluntary Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cumulative MWh Savings	13,902	19,585	22,697	28,464	38,817	46,765	58,923	68,672	76,031

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Report of IUB Staff, November 24, 1999.

Table 2-18 Municipal Utilities - MWh Savings Due to Voluntary Energy Efficiency

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Cumulative MWh Savings	23,645	47,290	55,656	64,021	73,820	83,227	89,925	96,882	100,010

Notes: The data for utilities' capacity and energy savings are the result of utilities' analyses of their programs, provided in formal filings and informal reports to the IUB. The chart above compiles the results of the utilities' data.
Sources: Report of IUB Staff, November 24, 1999.

Tables 2-19 through **2-21** present annual expenditures for energy efficiency and load management by IOUs (**Table 2-19**), RECs (**Table 2-20**), and municipal utilities (**Table 2-21**).

Table 2-19 Total Investor-Owned Utility Energy Efficiency and Load Management Expenditures ($1,000s)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Annual $ Expenditures	3,185	13,146	19,921	30,775	41,855	45,859	42,743	31,359	30,460	27,433

Sources: IOU Report, August 2, 2000, Tables 1.4.1.1.a and 1.4.1.1.b.

Table 2-20 Total Rural Electric Cooperative Voluntary Energy Efficiency and Load Management Expenditures ($1,000s) - Revised to Include Eastern Iowa REC

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Annual $ Expenditures	2,359	2,648	3,613	3,981	4,863	5,128	4,901	5,459	5,562

Sources: IUB Staff Report, September 16, 1999; Report from the IAEC, August 7, 2000.

Table 2-21 Total Municipal Utility Voluntary Energy Efficiency and Load Management Expenditures ($1,000s)

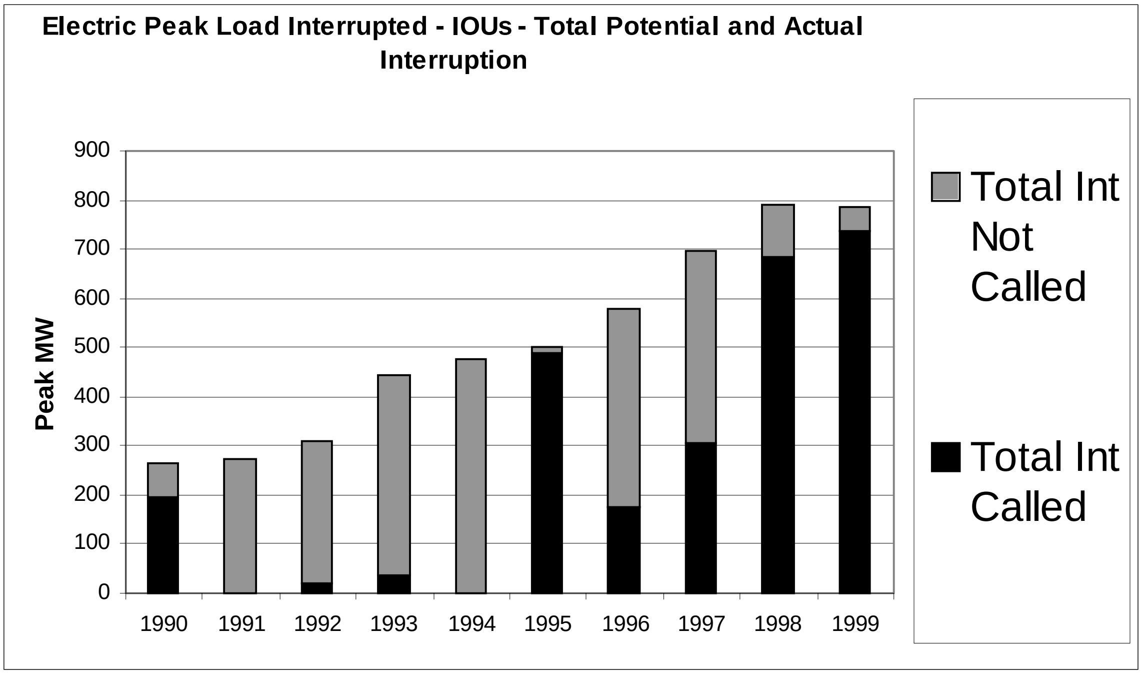
	1990	1991	1992	1993	1994	1995	1996	1997	1998
Annual $ Expenditures	3,222	3,222	3,218	3,218	2,098	1,741	2,108	2,144	2,144

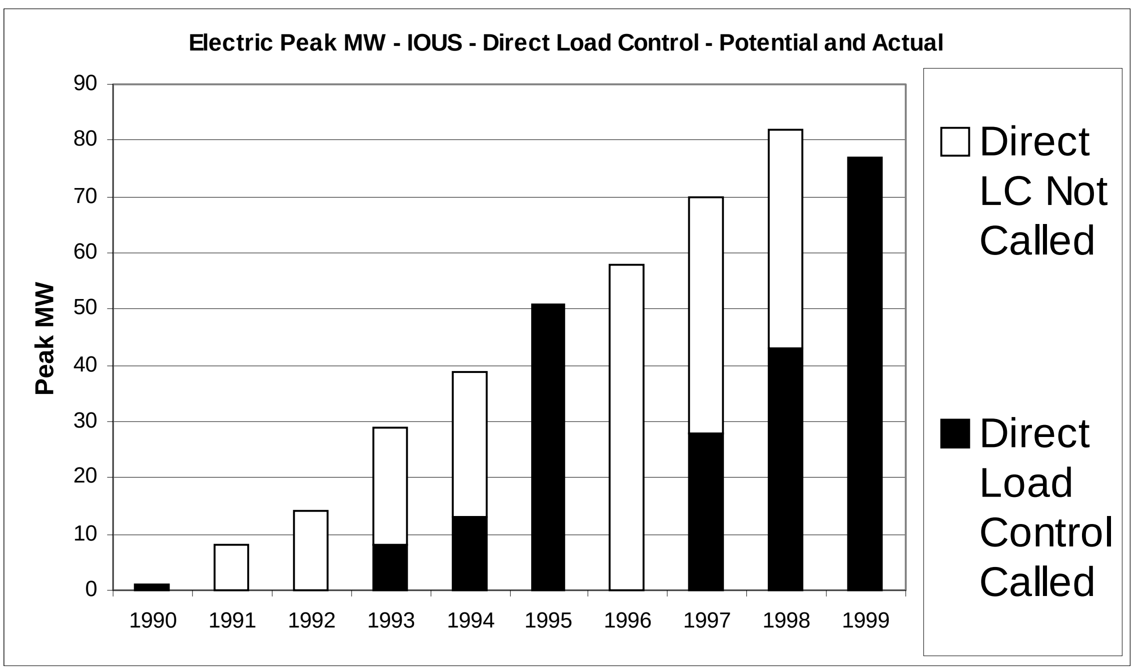
Notes: 1998 estimate from 1997.
Sources: IUB Staff Report, September 16, 1999.

2.2.3.3 Potential and Actual Load Management

Potential load management is the total load available for reduction by direct load control and interruptible load. Actual load management is the actual load reduction called for and achieved through direct load control or interruption. **Figure 2-9** compares potential and actual load management, for both interruptible load (Int) and direct load control (Direct LC), over the past several years for Iowa IOUs. **Figure 2-10** compares hourly load profiles, with and without load management, for Iowa IOUs, and for Alliant-West and MidAmerican individually, during the 1999 summer peak day (i.e., July 29, 1999).

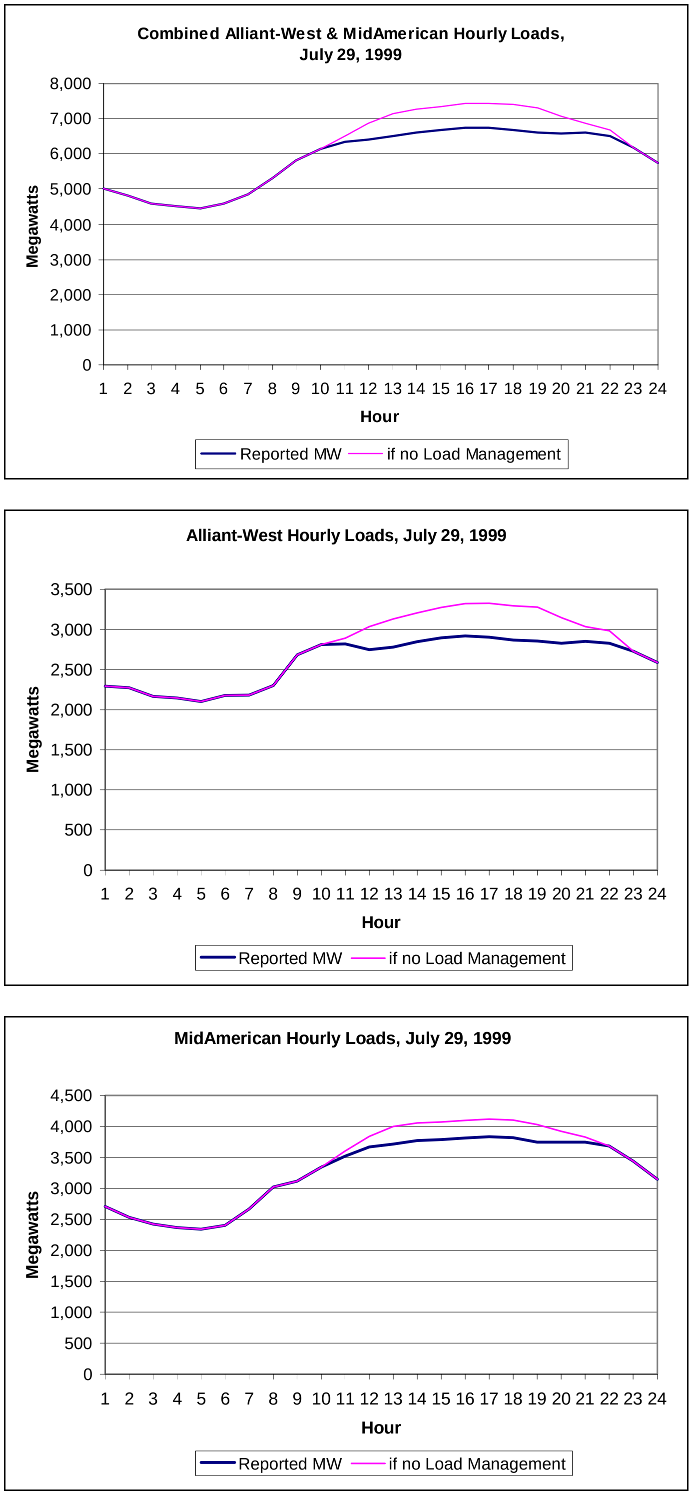
Figure 2-9 Interruptions and Peak Load Control for Investor-Owned Utilities -- Potential and Actual





Sources: Report by IOUs, August 12, 2000, Table 1.1.2.1b "Estimated Interruption Called (MWs)," Table 1.1.2.1c "Estimated Interruption Not Called (MWs)," Table 1.1.2.1d "Estimated Air Conditioner/Water Heating Called (MWs)," Table 1.1.2.1e "Estimated Air Conditioner/Water Heating Not Called (MWs)."

Figure 2-10 Peak Day Hourly Load Profiles for Iowa Investor-Owned Utilities With and Without Load Management



Sources: Internal company data compiled by Alliant and MidAmerican.

2.3 Electric Supply

Several sources of supply are available to meet the customer demand described in subsection 2.2. An Iowa utility may generate its own power for use by its consumers or it may purchase power from another utility or power marketer either in or outside the state. Subsection 2.3 provides data on the owned-generation of Iowa's utilities and IOU data related to purchased power commitments. Price data from the emerging wholesale market is provided, as well as other regional supply considerations. Limited data on the air emissions from fossil-fuel-fired generation are also presented. The subsection concludes with a brief discussion of Iowa's generation siting requirements.

2.3.1 Existing Generating Plants

Generating plants use a variety of fuel sources including water (or hydro), uranium (or nuclear), coal, gas, oil, biomass, and wind. Generating units using coal, gas, or oil are referred to as fossil-fuel-fired generating units. The size of a generating unit is commonly defined in megawatts (MW). The MW designation refers to the generating capacity of the unit. MW capacity multiplied by the number of hours in the year (8760) provides the maximum amount of electricity in megawatt hours (MWh) the plant is capable of producing in a given year assuming the unit is never unavailable due to maintenance or forced outage. Appendix D provides a list of utility generators providing power to Iowa consumers. Appendix E provides a list of non-utility generators providing power to Iowa consumers.[10]

This subsection provides historical information for all generating units owned by Alliant-West, all units owned by MidAmerican, and generating units owned by other Iowa utilities. Throughout this subsection, these generating units, plus MidAmerican's long-term capacity purchase from Nebraska Public Power District's Cooper Station ("Cooper Contract"), will be labeled "Iowa utility owned-generation." With the exception of the Cooper Contract, the data do not include purchased power commitments unless explicitly noted.[11] In addition, the plant data do not include generating facilities owned by non-Iowa entities selling power to Iowa utilities such as the generating facilities of Associated Electric Cooperative, Inc., Dairyland Power Cooperative, Ameren, the Western Area Power Administration, Basin Electric Power Cooperative, and Missouri River Energy Services.[12] Since purchased power (with the noted exceptions) is not included in these data, it would be inappropriate to use these data to

[10] These lists are not all inclusive.

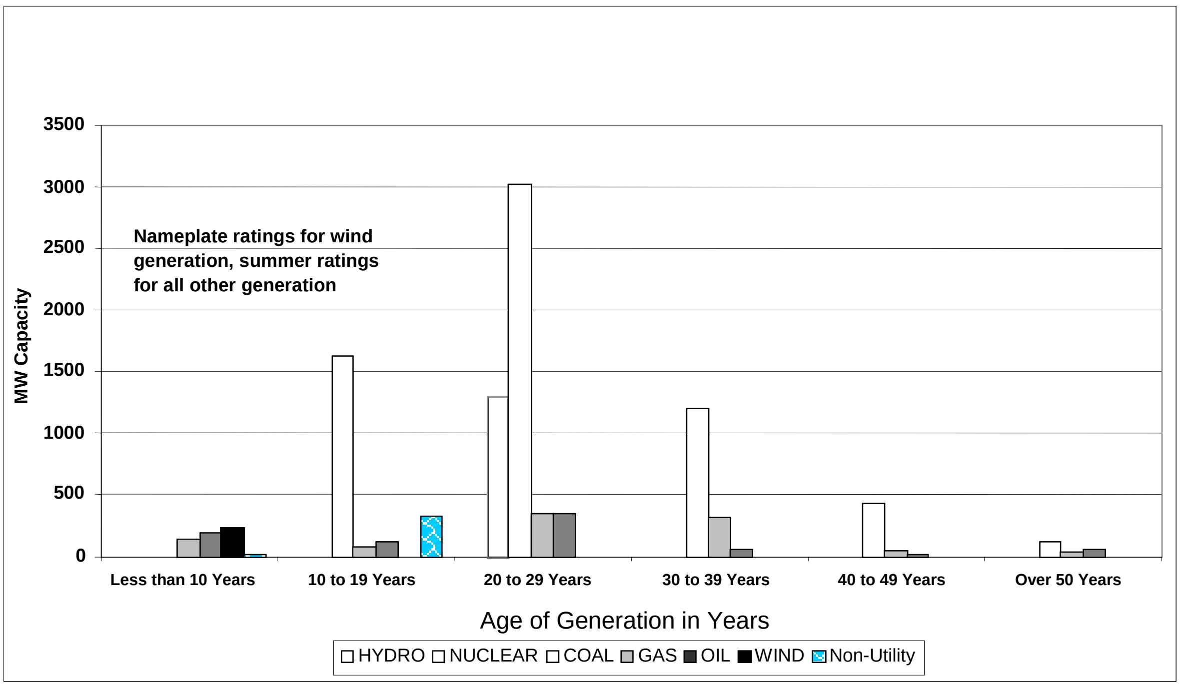
[11] In noted cases, the data include IOU wind contracts.

[12] Iowa municipal utilities that are members of Missouri River Energy Services (MRES) have rights of ownership in the Laramie River Station through MRES. The figures and tables in subsection 2.3 do not include this owned-generation. According to the IAMU, in 1999, Iowa utility sales from MRES equaled 185,419,770 kWh. This is less than one-half of one percent of total Iowa sales in 1999.

characterize Iowa's consumption fuel mix. The data may be used to characterize Iowa's production fuel mix.

Figure 2-11 illustrates the generating capacity of Iowa utility owned-generation plus the IOU wind contracts, plus non-utility generation. The non-utility category includes both units connected to the utility grid and units that serve only the electric customers' internal loads. The largest plants in this category are Archer Daniels Midland – Cedar Rapids (155 MW), Iowa State University – Ames (33 MW), University of Iowa – Iowa City (21 MW), Cargill, Inc. – Corn Milling Division (16 MW) and Industrial Energy Applications 9 (16 MW). **Table 2-22** provides the data used in **Figure 2-11**.

Figure 2-11 Generating Capacity by Age and Type (MW)



Sources: EIA-412, RUS-12, FERC FORM 1 and other sources as compiled by Resource Data International, Inc. Figure 2-13 provided by MidAmerican and Alliant.

Table 2-22 Generating Capacity of Iowa Utility Owned-Generation plus the IOU Wind Contracts by Age and Type (MW)

	Less than 10 Years	10 to 19 Years	20 to 29 Years	30 to 39 Years	40 to 49 Years	50+ Years	Total By Fuel
Coal	0	1,625	3,023	1,193	426	124	6,391
Gas	132	79	347	315	44	32	949
Hydro	0	2	0	0	0	5	7
Nuclear	0	0	1291	0	0	0	1,291
Oil	195	126	346	63	14	64	808
Wind	237	0	0	0	0	0	237
Non-Utility	16	334	0	0	0	0	350
Total	580	2,166	5,007	1,571	484	225	10,033

Notes: Nameplate ratings were used for wind generation, and summer ratings were used for all other generation. Over 300 MW of non-utility generation are shown as fuel type "Non- Utility."
Sources: EIA-412, RUS-12, FERC FORM 1, and other sources as compiled by Resource Data International, Inc. Data provided by MidAmerican.

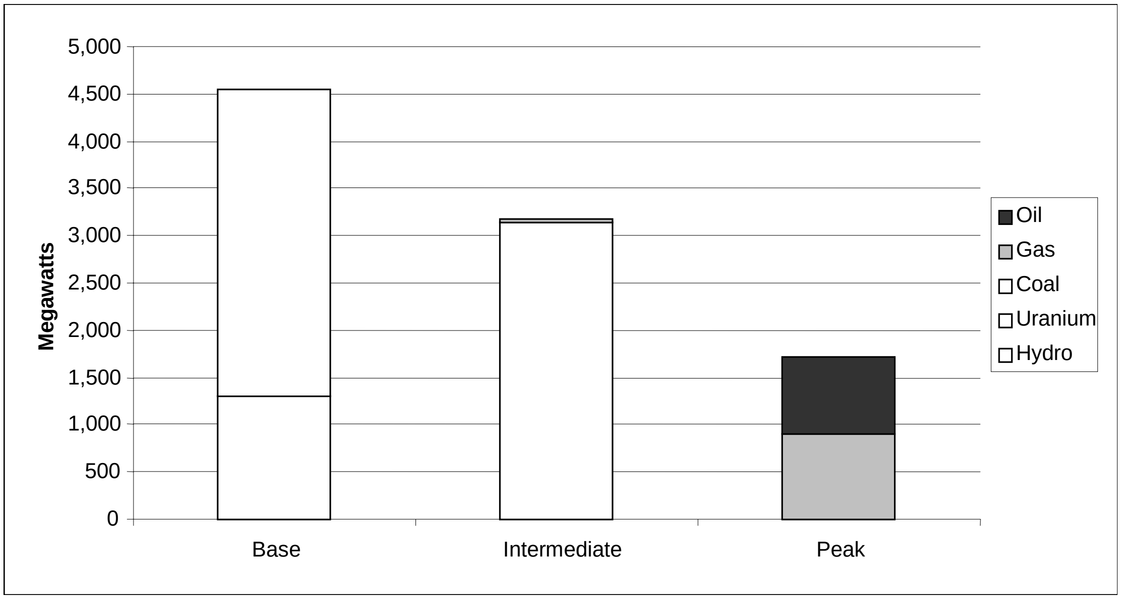
Generating plants are typically classified as base, intermediate, or peaking based on operation, unit type, fuel type, size of unit, age of unit, and average annual heat rate (i.e., efficiency). Base load units generally include hydro units, nuclear units, and newer, larger coal-fired units. Some extremely efficient gas-fired units may also be operated as base load units. Intermediate units generally include older or smaller coal fired units, gas-fired steam units, and newer, more efficient gas-fired units. Peaking units generally include gas- and oil-fired combustion turbines and internal combustion engines.

Figure 2-12 and **Table 2-23** classify generating units in Iowa by typical use. Generating units were classified using the following criteria:

- Base - A plant that is operated whenever it is available. The plant's output may be reduced for decreased load or market price conditions.
- Intermediate - A plant operated a substantial portion of the time. Depending on the system, intermediate units typically operate 1,500 to 5,000 hours per year.
- Peaking - A plant used to generate electricity only for the highest system loads. Peaking plants are typically used up to 1,500 hours per year.

Two other types of units have not been classified as base, intermediate, or peaking, because they cannot be dispatched by electric utilities. Wind units provide electricity only when wind is available. Units classified as "unknown" include a group of non-utility generators that serve their own loads or sell excess generation to utilities.

Figure 2-12 Use of Iowa Utility Owned-Generation



Sources: EIA-412, RUS-12, FERC FORM 1 and other sources as compiled by Resource Data International; Data Provided by MidAmerican/Illustrated by IUB Staff.

Table 2-23 Typical Use of Iowa Utility Owned-Generation

Type of Use	Fuel Type	Capacity (MW)
Base	HYDRO	8
Base	URANIUM	1,291
Base	COAL	3,254
Intermediate	COAL	3,137
Intermediate	GAS	40
Peak	GAS	909
Peak	OIL	808

Sources: EIA-412, RUS-12, FERC FORM 1, and other sources as compiled by Resource Data International, Inc.; Data provided by MidAmerican.

2.3.1.1 Historical Fuel Use and Efficiency

The goal of economic dispatch is to efficiently dispatch the available mix of generating units on an electric system to provide the least-cost electric energy to serve a range of system demands. Since fuel cost is the largest portion of the cost to operate a generating unit (except for wind and hydro generation), fuel cost may be used to develop a preliminary order of units to be dispatched to serve load. Since the fuel costs for uranium are lower than fossil fuel, nuclear units are normally dispatched after hydro units and before any fossil-fuel-fired units. Coal-fired units are generally brought on-line before any gas- or oil-fired generation is brought on-line because coal is the lowest cost fossil fuel. Wind turbines are used whenever available.

Unit efficiency may change the preliminary unit dispatch order based on fuel cost. Unit efficiency is measured by the unit heat rate. The heat rate equals the quantity of energy input (measured in British thermal units, or Btus) divided by the quantity of energy output (measured in kWhs). The lower the heat rate, the more efficient the unit. The measured heat rates for units vary depending on the design, age, and condition of the unit, ambient temperature, and the level of operation.[13] High efficiency, combined cycle gas units may have heat rates well below coal-fired steam units. Even though the cost of gas is currently substantially higher than the cost of coal, there is a crossover point based on the relative cost of gas and coal where a high efficiency combined cycle gas unit would have a lower input fuel cost than a low-efficiency coal unit. In this case, the coal unit would move higher in the dispatch ranking than the combined cycle gas unit.

Additional factors that may change the system-wide economic dispatching of generating units include:

- Area Protection – Provide support to the transmission system in an area.
- Transmission Relief – Adjust transmission line flows by changing generation levels to ease transmission congestion.
- Must-Run Units – Keep a unit on-line in order to minimize the unit's cost of operation, startup, shutdown costs, and "wear and tear" costs, or for conditions requiring continuous operation of those units. Conditions that might require continued unit operation include unit testing or a need to burn coal from in-plant storage.
- Limited Operating Hours – Restrict a unit's operation to comply with environmental restrictions.

[13] Each generating unit's heat rate varies over the normal operating range of the unit. Nearly all units are less efficient as the capacity approaches the unit's minimum generation level, and most efficient near the maximum generation level. As a result, the cost to operate a generating unit, assuming a constant fuel cost, will decrease in terms of cents per kilowatt-hour as the unit's output is increased. Warmer ambient temperatures generally reduce the operating capability of generating units.

Table 2-24 provides historical annual generation for Iowa utility owned-generation by unit type. In this case, generation is characterized in GWh. Steam (fossil) generation (as presented in the table) is typically fueled by coal, gas, or oil.

Table 2-24 Iowa Electric Utility Owned-Generation by Plant Type (GWh)

Year	Steam Generation GWh	Nuclear Generation GWh	Hydro Generation GWh	Other Generation GWh	Total Generation GWh
1990	22,850	7,192	25	72	30,139
1991	23,843	7,629	24	125	31,621
1992	24,191	8,656	26	26	32,899
1993	25,638	6,878	12	97	32,625
1994	26,135	6,671	23	107	32,936
1995	28,201	7,921	21	104	36,247
1996	28,034	8,941	20	69	37,064
1997	28,721	8,923	19	254	37,917
1998	31,403	9,001	20	436	40,860
1999	31,407	10,144	23	391	41,965

Notes: Includes all generating units located in Iowa and other units owned and operated by Alliant-West located outside Iowa. Also includes MidAmerican's share of the Quad Cities nuclear station in Illinois and MidAmerican's 50 percent share of output from the Cooper nuclear station in Nebraska. Does not include non-utility generation, such as wind.
Sources: EIA-412, RUS-12, FERC FORM 1 and other sources as compiled by Resource Data International, Inc.; Data provided by MidAmerican.

Table 2-25 shows historical capacity factors by plant type. The capacity factor of a generating plant, or group of plants, represents the percentage of electricity the plant actually generated compared to electricity it is capable of generating for a specific time period.

Factors that may affect the capacity factor of each type of plant include:

- Economic dispatch – Use of the lowest-cost generation to serve load.
- Load following – Adjustments to the amount of total generation to match the load. Loads, including customer loads plus sales less purchases, change almost constantly. These changes require changes to the mix of generating units producing electricity.
- Scheduled Maintenance – Periods when units are out of service for maintenance.
- Forced outage – Periods when the unit must be shut down or generation must be reduced to perform unscheduled maintenance and repairs.

The increase in capacity factors for coal and nuclear units are primarily due to increases in native load energy requirements and increased energy sales to other utilities. Increased unit availability of nuclear units also results in higher capacity factors for those units.

Table 2-25 Capacity Factors by Utility Plant Type for Iowa Utility Owned-Generation

Year	Steam	Nuclear	Hydro	Other
1990	49.1%	72.2%	54.0%	0.8%
1991	51.2%	76.6%	53.3%	1.3%
1992	47.6%	76.2%	56.8%	0.3%
1993	51.8%	63.3%	27.4%	0.9%
1994	51.1%	58.9%	51.2%	0.9%
1995	55.2%	69.9%	46.3%	0.9%
1996	54.9%	78.7%	44.7%	0.6%
1997	56.2%	78.9%	41.6%	2.1%
1998	61.3%	79.6%	44.7%	3.5%
1999	62.5%	90.1%	49.5%	2.9%

Notes: Capacity factors were calculated using the higher of the reported summer or winter capacity and net annual generation, excluding station use. Reflects the same generating units as Table 2-24.
Sources: EIA-412, RUS-12, FERC FORM 1, and other sources as compiled by Resource Data International, Inc.; Data provided by MidAmerican.

Table 2-26 shows the percentage of each type of fuel used for Iowa utility owned- generation. For comparison purposes, the quantity of each fuel used was converted to Btus, a measure of heat content.[14]

Table 2-26 Percent of Heat Input by Fuel Type - Iowa Utility Owned-Generation

Fuel Type	1995	1996	1997	1998	1999
COAL	74.2%	74.5%	74.6%	78.1%	75.1%
URANIUM	23.8%	23.9%	23.5%	19.8%	23.2%
GAS	1.7%	1.3%	1.5%	1.7%	1.3%
OIL	0.2%	0.2%	0.3%	0.3%	0.3%
WOOD	0.1%	0.1%	0.1%	0.1%	0.1%
OTHER	0.0%	0.0%	0.0%	0.0%	0.0%
WATER	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

Notes: This table lists the percent of heat input of each fuel at all types of plants. The gas percentage includes gas used at plants with primary fuel types of coal, oil, or other primary fuels. Reflects the same generating units as Table 2-24.
Sources: EIA-412, RUS-12, FERC FORM 1 and other sources as compiled by Resource Data International, Inc.; Data provided by MidAmerican.

[14] Typical Btu conversion rates are: Low Btu coal – 8,400 Btus per pound, high Btu coal – 10,500 Btus per pound, natural gas – 1000 Btu per cubic foot and oil – 140,000 Btus per gallon.

2.3.1.2 Projected Fuel Diversity

The Energy Information Administration (EIA) conducts energy forecasts for the U.S. The EIA[15] produced estimates of U.S. energy consumption by sector for three scenarios: a reference case, a low economic growth case, and a high economic growth case. **Table 2-27** shows the EIA value for actual Btus used in 1998 and the forecast of the number of Btus used to produce electricity in 2010. **Table 2-27** also shows the annual average growth in the use of each type of fuel from 1998 to 2010 under each EIA growth scenario.

Table 2-27 U.S. Energy Consumption for Electric Generators (Quadrillion Btu per year) and Annual Average Change in Consumption from 1998 to 2010

		1998 Reference	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth
Oil	Consumption	1.2	0.4	0.5	0.7
	Annual change		-9.5%	-8.0%	-4.6%
Natural Gas	Consumption	3.8	6.1	6.6	7.3
	Annual change		4.5%	4.8%	5.7%
Steam Coal	Consumption	19.0	22.2	22.5	23.2
	Annual change		1.3%	1.4%	1.7%
Nuclear	Consumption	7.2	6.7	6.7	6.7
	Annual change		-0.6%	-0.6%	-0.6%
Renewable	Consumption	4.1	4.4	4.4	4.4
	Annual change		0.6%	0.6%	0.6%

Sources: Energy Information Administration, Annual Energy Outlook 2000, Table b2. Energy Consumption by Sector and Source, pp. 146-147.

Table 2-28 shows EIA's forecasted change in the percent of fuel heat input used to generate electricity.

[15] Energy Information Administration, Annual Energy Outlook 2000, Table b2. Energy Consumption by Sector and Source, pp. 146-147

Table 2-28 U.S. Energy Consumption for Electric Generators - Type of Fuel Used as a Percentage of Total Fuel for Generation

	1998 Reference	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth
Oil	3.5%	0.9%	1.1%	1.6%
Natural Gas	10.5%	15.3%	16.1%	17.1%
Steam Coal	53.3%	55.5%	55.1%	54.5%
Nuclear	20.2%	16.7%	16.3%	15.8%
Renewable Energy	11.6%	11.0%	10.8%	10.4%
Electricity Imports	0.9%	0.6%	0.6%	0.6%
Total	100.0%	100.0%	100.0%	100.0%

Sources: Energy Information Administration, Annual Energy Outlook 2000, Table b2. Energy Consumption by Sector and Source, pp. 146-147.

The EIA forecast indicates an increase in the amount of energy used to generate electricity of about 1 percent per year from 1998 to 2010. Use of coal and gas to produce electricity, both in terms of Btus and as a percentage of fuel used, increases from 1998 to 2010. EIA forecasts a decrease in total energy from nuclear units from 1998 to 2010. Total energy from oil is also forecasted to decline from 1998 to 2010.

2.3.1.3 Cost of Generation

Table 2-29 presents historical costs per MWh delineated by fuel type and expense category.[16] Generation expenses are often categorized as fuel and non-fuel. As stated previously, fuel is the primary cost component of fossil-fuel-fired generation. Non-fuel expenses play a larger role in nuclear and hydro generation.

Table 2-29 Generation Cost per MWh by Fuel Type - Iowa Generation

	Steam Generation ($/MWh)			Nuclear Generation ($/MWh)			Hydro Generation ($/MWh)		
Year	Fuel	Non-Fuel	Total	Fuel	Non-Fuel	Total	Water Expense	Non-Water Expense	Total
1990	13.45	3.56	17.00	6.10	15.45	21.55	0.16	8.88	9.04
1991	13.64	3.82	17.45	5.96	15.07	21.03	0.04	10.58	10.63
1992	13.08	4.10	17.17	5.32	16.24	21.56	0.00	11.46	11.46
1993	12.45	4.01	16.46	5.67	21.29	26.96	0.00	14.83	14.83
1994	12.06	4.05	16.11	6.34	25.29	31.63	0.00	10.52	10.52
1995	11.88	3.43	15.31	6.49	20.88	27.37	0.00	9.05	9.05
1996	11.79	3.43	15.22	6.38	16.16	22.55	0.00	10.75	10.75
1997	11.73	3.62	15.36	6.20	18.29	24.49	0.00	33.47	33.47
1998	10.73	3.48	14.21	5.21	16.89	22.10	0.00	17.70	17.70
1999	10.01	3.54	13.55	5.50	14.72	20.22	0.00	24.61	24.61

Sources: EIA-412, RUS-12, FERC FORM 1 and other sources as complied by Resource Data International, Inc.; Base data provided by MidAmerican and presented by IUB staff.

2.3.2 Purchased Power

Purchased power is another source of supply used to serve Iowa's load and energy requirements. This subsection presents: 1) historical and projected purchased power commitments as accredited with MAPP; 2) a discussion and delineation of IOU purchases from alternate energy sources (more commonly known as renewable energy sources); and 3) summary data from the Midwest's wholesale spot electricity market.

[16] These costs do not include capital costs, depreciation expenses, taxes, or generation overhead.

2.3.2.1 Purchased Power Commitments for Iowa's IOUs

Table 2-30 provides historical and projected purchased power commitments for MidAmerican and Alliant-West including the total of summer firm and participation sales accredited with MAPP.

Table 2-30 Historical and Projected Purchased Power Commitments (MW)

	MidAmerican Energy				Alliant-West		
	Total Purch.	Total Sales	Net Purch.		Total Purch.	Total Sales	Net Purch.
1990	551	338	213		236	20	216
1991	561	384	177		206	0	206
1992	847	570	277		374	10	364
1993	792	605	187		406	75	331
1994	786	571	215		416	75	341
1995	756	556	200		446	75	371
1996	672	406	266		426	75	351
1997	634	299	335		455	60	395
1998	630	287	343		425	0	425
1999	620	289	331		530	7	523
2000	809	256	553		585	162	423
2001	439	5	434		237	7	230
2002	429	0	429		361	7	354
2003	429	0	429		361	7	354
2004	429	0	429		336	7	329
2005	50	0	50		336	7	329
2006	50	0	50		336	7	329
2007	50	0	50		336	7	329
2008	50	0	50		336	7	329
2009	46	0	46		36	7	29

Notes: Total purchases and sales equal total firm and participation power transactions accredited with MAPP. MidAmerican purchases include approximately 385 MW participation power purchase contract with Cooper Power Station each year from 1990 through 2004. Net purchases equal total purchases less total sales. In 2000, MidAmerican reported for utilities included in Appendix C plus Estherville Municipal Utility. Alliant-West reported for IES, Interstate, and Central Iowa Power Cooperative.
Sources: Historical: MAPP Annual Load & Capability Reports, 1990-1999; Forecast: MAPP Load & Capability Report, May 2000 for MidAmerican Energy, and Alliant-West.

MidAmerican's firm purchase power contract with Cooper Power Station is included in both **Table 2-30** and in the data labeled Iowa utility owned-generation in subsection 2.3.2. As such, adding the MW capacity in **Table 2-22** with MW net purchases in **Table 2-30** would overstate MidAmerican's existing capacity.

2.3.2.2 Power Purchases from Alternate Energy Sources (Background and Summary Table)

The Alternate Energy Production (AEP) statute (Iowa Code Section 476.41 – 476.45) was enacted in 1983 to encourage development of AEP facilities by establishing special incentive rates for AEP purchases by IOUs. Federal law requires utilities to purchase AEP at rates based on the utilities' incremental avoided costs.[17] However, avoided-cost rates were not considered high enough to encourage AEP development, so the Iowa AEP statute was designed to provide higher incentive rates.

The first IUB rulemaking implementing the AEP statute was initiated in 1983 (Docket No. RMU-83-30) and provided for a statewide utility purchase rate of 6.5 cents per kWh for AEP. The statewide rate was challenged by Iowa's electric utility companies and eventually overturned by the Iowa Supreme Court in 1987. The Court ruled that the Board's rules went beyond the AEP statute, because it set a statewide AEP purchase rate rather than utility-specific rates, and because the Board disregarded rate-determining factors specified in the AEP statute. The Court also ruled that the AEP statute could not be applied to non-rate regulated utilities (i.e., municipal utilities and RECs).

The Board proposed new rules in January 1988 (Docket No. RMU-88-4), attempting to establish utility purchase rates that would encourage AEP development, while being based on the AEP statute's rate-determining factors. However, both these criteria could not be satisfied under current statute. Changes in the statute's rate-determining factors were needed to design sufficient incentive rates.

These statutory changes were enacted in 1990, making it possible for the Board to design utility purchase rates high enough to encourage AEP development.[18] The Board implemented these changes through rules effective June 1991 (Docket No. RMU-90-35). The rules established statewide utility purchase rates for AEP capacity and energy based on revised rate-determining factors. The rates were adjustable according to the length of the AEP contract, up to a maximum combined rate of approximately 6-cents per kWh.

In 1992, the statutory 15 MW purchase obligation for each utility was changed to a proportional share of 105 MW, based on each utility's share of the utilities'

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[17] The cost the utility would otherwise incur in producing the power itself or purchasing it from other sources.

[18] Specifically, the changes: 1) permitted the Board to set statewide AEP purchase rates based on representative data; 2) changed the definition of "next generating plant" to be the "electric utility's next coal-fired base load electric generating plant, whether planned or not, based on current technology and undiscounted current cost;" and 3) allowed the Board to consider environmental and economic externality factors. A further provision limited each utility's AEP purchase obligation to 15 MW.

combined Iowa electric peak demand. The IUB implemented this change through rules effective July 1993 (Docket No. RMU-92-16).

In 1996, the Alternate Energy Revolving Loan Program (Iowa Code Section 476.46) was enacted to provide low-interest loan incentives for AEP development. This program is administered by the Iowa Energy Center.

In 1995, an Iowa utility petitioned the FERC to overturn the AEP statute and IUB rules to the extent they required utilities to pay more than their avoided costs for AEP (FERC Docket No. EL95-51-000). The FERC responded in January 1997 by overturning the Board's incentive purchase rates for AEP. However, the FERC also ruled that, under the AEP statute, the Board could require utilities to purchase alternate energy. Therefore, in the context of a contested proceeding (Docket Nos. AEP-95-1 through AEP-95-5), the Board required Iowa's IOUs to fulfill the remainder of their AEP purchase obligations by a date certain. The IOUs responded by issuing requests for proposals (RFPs) and awarding renewable energy purchase contracts for AEP projects intended to fulfill their statutory purchase obligation. Most of these projects became commercially operational in 1999.

Table 2-31 shows historical renewable energy purchases by Iowa utilities over the past five years (1995-99). The amounts shown include hydropower from the Western Area Power Administration (WAPA) and Southwestern Power Administration (SWPA), purchased voluntarily by IOUs, RECs, and municipal utilities, apart from the requirements of the AEP statute.

Table 2-31 Renewable Energy Purchases by Iowa Utilities (MWh = 1,000 kWh)

	1995 MWh	1996 MWh	1997 MWh	1998 MWh	1999 MWh
Wind	1,006	1,442	3,266	9,069	475,280[19]
Hydro	13,643	19,740	22,170	22,641	20,646
WAPA Hydro[20]	1,472,505	1,986,982	2,696,261	1,800,177	N/A
SWPA Hydro[21]	38,000	38,000	38,000	38,000	38,000
Biomass	42,513	47,683	46,410	55,055	85,367
Other	2,521	4,128	2,901	1,984	2,167
Total	1,570,188	2,097,705	2,809,008	1,926,926	621,460[22]
25 Hz Hydro[23]	308,953	277,337	130,233	37,731	37,436
Total Including 25 Hz Hydro	**1,879,141**	**2,375,042**	**2,939,241**	**1,964,657**	**658,896**[24]
Total Iowa MWh Sales	34,301,000	34,999,000	36,148,000	37,318,000	N/A
Renewable Purchases as a Percent of Total Iowa MWh Sales	**5.5%**	**6.8%**	**8.1%**	**5.3%**	**N/A**

Sources: Internal company data compiled by Alliant and MidAmerican, and data compiled by the Iowa Association of Electric Cooperatives (IAEC) and the Iowa Association of Municipal Utilities (IAMU); total Iowa MWh sales are from *Electric Power Annual*, Vol. II, 1996-98, Energy Information Administration (EIA), Table 4, compiled by IUB Staff.

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[19] Reflects approximately seven months purchases from large wind farms, beginning in the second quarter of 1999, plus 10,936 MWH of wind generation and wind purchases by municipal utilities. For the period July 1999 through June 2000, investor-owned utility wind purchases totaled 620,073 MWH.

[20] Hydropower purchases from WAPA by Iowa IOUs, RECs, and municipal utilities. Note that some groups do not characterize large hydro as renewable.

[21] Hydropower purchases from SWPA by Iowa RECs. Note that some groups do not characterize large hydro as renewable.

[22] Total does not include WAPA hydropower purchases – data not available for 1999.

[23] The 25 Hz hydro purchases present a unique situation that warrants separate mention, because it is based on older technology, not usable by most customers (60 Hz generation is the current industry standard). The 25 Hz hydro plant is owned by Union Electric Company. IES Utilities (part of Alliant-West) purchases the power from Union Electric under special arrangement to serve its 25 Hz industrial customers, acquired when IES purchased Union Electric's southeast Iowa service territory. As previous contracts expire between IES and its remaining 25 Hz customers, the customers are converted to standard 60 Hz power. Thus, IES's 25 Hz hydropower purchases are steadily phased out over time.

[24] Total does not include WAPA hydropower purchases – data not available for 1999.

2.3.2.3 Wholesale Spot Market

As described in subsection 1.2 – Background, the Energy Policy Act of 1992 (EPACT), coupled with FERC Order 888, created a wholesale spot market in electricity. Specifically, the EPACT advanced the growth of non-utility power producers by creating a new class of non-utility generators called "exempt wholesale generators" (EWGs). The EPACT allowed companies, including public utility holding companies, to develop and operate EWGs anywhere in the world. EWGs may sell wholesale power at market rates and are exempt from the cost-of-service regulation to which utilities are subject. Utilities must provide wholesale power transmission service to EWGs and other third parties at cost-based rates, under the same open access transmission regulations as any other capacity. The impact of the EPACT can be seen in the growth in the number of non-utility generating facilities. From 1997 to 1998, the total installed capacity of non-utility generating facilities grew 32.5 percent.[25] Non-utility capacity in 1998 was equivalent to 12.6 percent of the total U.S. electric industry capacity[26] compared to 7 percent in 1991.[27] The FERC implemented the provisions of the EPACT, in part, through FERC Order 888.

The EPACT and Order 888 enabled new organizations, such as power marketers, to purchase, transmit and resell electric power across traditional electric utility borders. Power marketers, like traditional utilities, buy and sell electric power in the wholesale market. Some of these power marketers own generation, however none of them own transmission or distribution facilities. The number of registered power marketers with wholesale rates approved by the FERC has grown substantially in the past few years from 11 in 1993 to approximately 400 in 1998, of which about 90 are affiliated with traditional electric utilities.[28]

The wholesale spot market in electricity is another source of supply to serve Iowa's load and energy requirements. **Figure 2-13** tracks the wholesale market prices in the MAPP region for the summer in the years 1998, 1999, and 2000. **Figure 2-14** provides average next day firm prices for different regions of the Midwest by year. Spikes in wholesale spot prices for electricity occur when capacity and/or energy in the region is in short supply.

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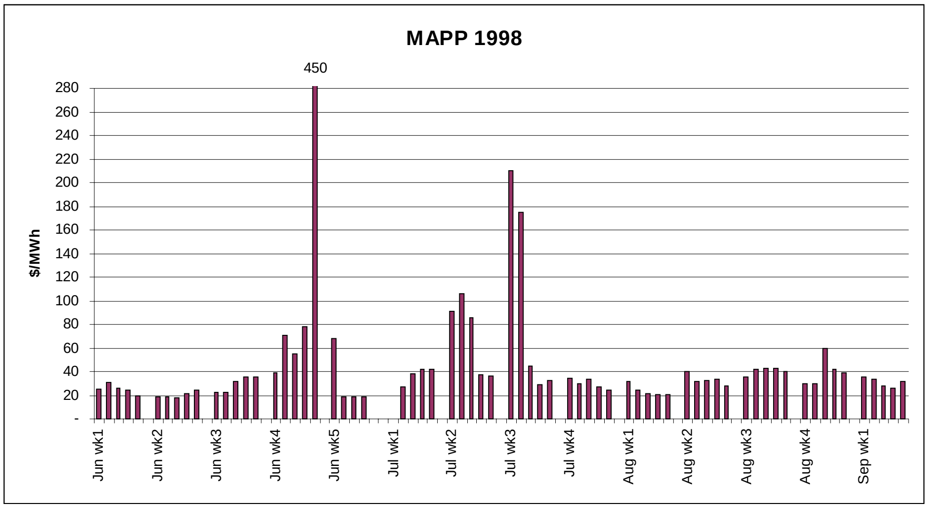
[25] Electric Power Annual 1998, Vol. II, Energy Information Administration, December 1999, p. 10. Much of the increase was caused by the sale of utility generating facilities to non-utility companies.

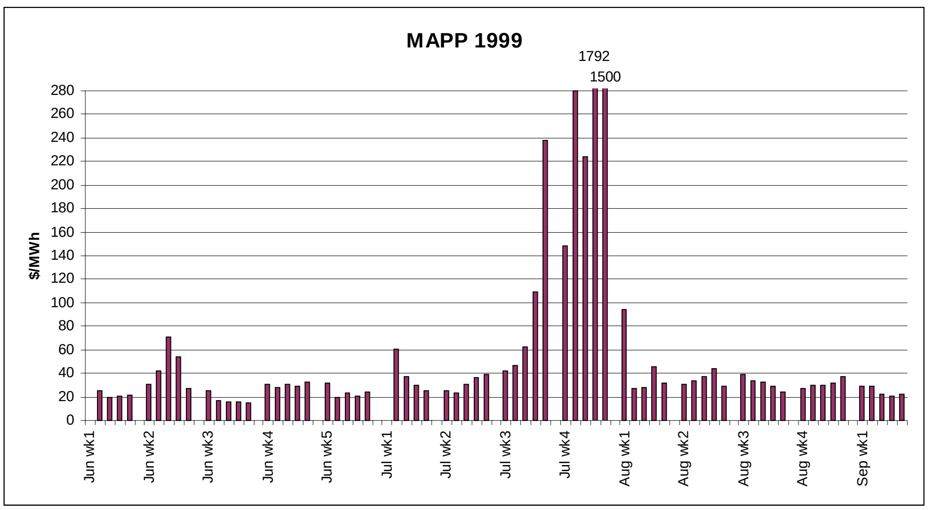
[26] Electric Power Annual 1998, Vol. II, Energy Information Administration, December 1999, p. 10.

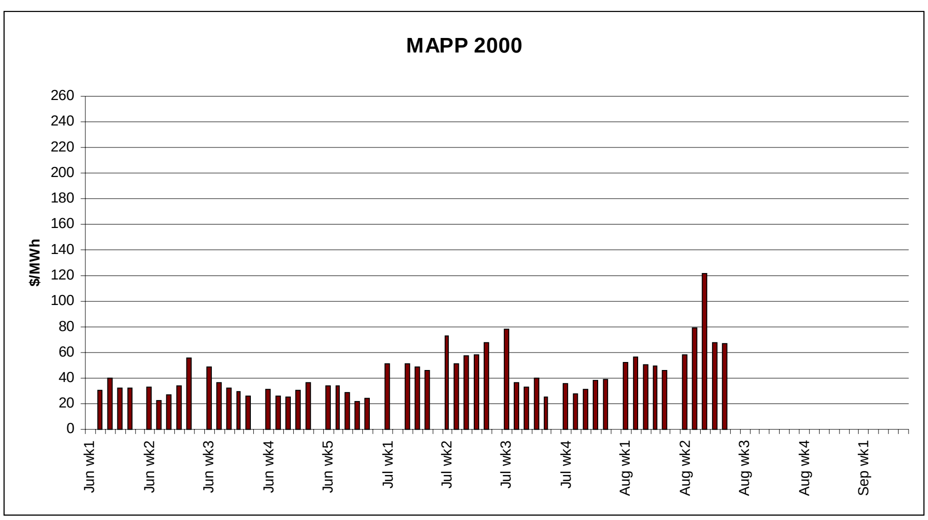
[27] Electric Power Annual 1991, Energy Information Administration (EIA-0348(91)), February 1993, p. 9.

[28] Electric Sales and Revenue 1998, Energy Information Administration, pp. 247-248. However, fewer than half of those registered with the FERC in 1998 actually conducted wholesale transactions.

Figure 2-13 Average Next-Day Firm Electricity Prices -- MAPP Region

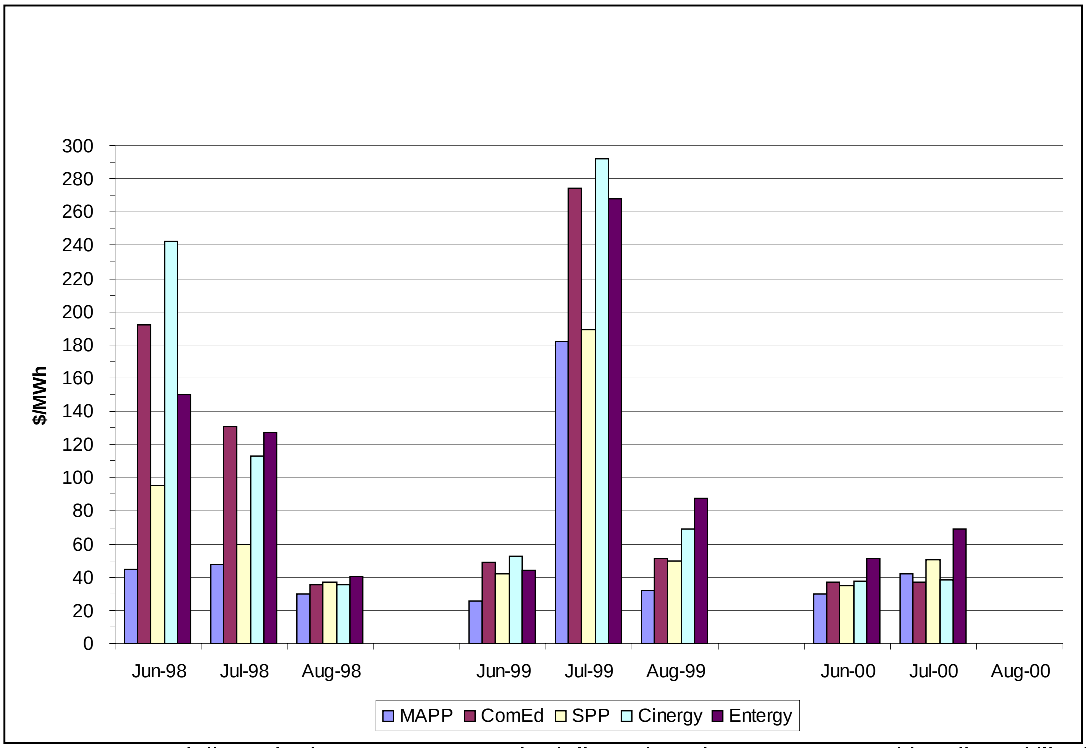






Source: MegawattDaily.

Figure 2-14 Average Next-Day Firm Electricity Prices -- Midwest Region, 1998-2000



Notes: MAPP: delivery in the MAPP; ComEd: delivery into the Commonwealth Edison (Illinois) System; SPP: delivery into the Southwest Power Pool; Cinergy: delivery into the Cinergy system, comprising the old systems of Public Service of Indiana and Cincinnati Gas & Electric; Entergy: delivery into the Entergy system (Arkansas/Louisiana).
Source: MegawattDaily.

2.3.3 Regional Generation Supply Considerations

As new capacity is added to the region, the expectation would be the lowering of the cost of purchased power contracts and spot wholesale prices. **Table 2-32** provides the planned generation additions in the Midwest by regional reliability council. “Under development” is defined as all generation characterized as follows: operational, under construction, all permits received, or undergoing permit and/or certification review. Announced generation may or may not materialize depending on demand and regional market conditions. The all-time summer peak demand is also provided to give context to the capacity additions. Appendix F provides a detailed list of these capacity additions.

Table 2-32 Planned Generation Additions in the Midwest (MW)

NERC Region		Projected Operational Start Date: 2000	2001	2002	2003	>2003 or unknown	Totals	All-time Summer Peak Demand
ECAR	Under development	3,713	2,790	4,240	2,100	1,350	14,193	
	Announced	894	3,110	5,580	4,080	6,430	20,094	
	Total	4,607	5,900	9,820	6,180	7,780	34,287	96,149
MAIN	Under development	4,068	4,867	2,210	0	6,794	17,939	
	Announced	326	900	775	2,450	910	5,361	
	Total	4,394	5,767	2,985	2,450	7,704	23,300	49,027
MAPP	Under development	300	1,147	0	0	114	1,561	
	Announced		505	90	430	89	1,114	
	Total	300	1,652	90	430	203	2,675	37,196
SPP & Entergy	Under development	1,949	3,841	7,142	0	320	13,252	
	Announced	699	1,639	1,950	1,100	1,160	6,548	
	Total	2,648	5,480	9,092	1,100	1,480	19,800	58,473
Total Midwest	Under development	10,030	12,645	13,592	2,100	8,578	46,945	
	Announced	1,919	6,154	8,395	8,060	8,589	33,117	
	Total	11,949	18,799	21,987	10,160	17,167	80,062	

Notes: Under Development = Operational, Under Construction, All Permits Received, or Undergoing Permit and/or Certification Review

Sources: All-Time Peak Demand - North American Electric Reliability Council 2000 Summer Assessment. For each region, the all-time summer peak demand occurred in 1999.

Proposed Projects - Numerous sources including: Company news releases, Electric Utility Week, MegawattDaily, Illinois Environmental Protection Agency, Wisconsin Department of Natural Resources, Ohio Power Siting Board, Minnesota Environmental Quality Board Monitor, Oklahoma Department of Environmental Quality, Mississippi Public Utility Commission, Indiana Environmental Protection Agency, Michigan Department of Environment Quality, and the North American Electric Reliability Council 2000 Summer Assessment.

Table 2-33 provides the planned Midwest MW capacity additions by fuel type. The table also provides the total of historical additions (years 1992-1999) by fuel type including the percent of total.

Table 2-33 Planned Midwest Capacity Additions by Fuel Type (MW)

Primary Fuel	2000	2001	2002	2003	>2003 or unknown	Percent of Total – Historical 1992-99	Percent of Total Planned >1999
Natural Gas	11,318	18,245	21,222	9,760	13,361	87.0%	92.3%
Oil	374				33	6.2%	0.5%
Coal	74	26	540	400	1,045	0.5%	2.6%
Uranium	53	178	225			0.0%	0.6%
Wind	30	350				2.9%	0.5%
Pumped Storage						1.2%	0.0%
Hydro	80					2.2%	0.1%
Compressed Air					2,700	0.0%	3.4%
Solid Waste	20					0.0%	0.0%
Unknown					28	0.0%	0.0%

Notes: "Planned" addition includes projects that are operational, under construction, all permits received, undergoing permit review, and announced. Additions are not net of unit retirements.
Sources: Company news releases, Electric Utility Week, MegawattDaily, Illinois Environmental Protection Agency, Wisconsin Department of Natural Resources, Ohio Power Siting Board, Minnesota Environmental Quality Board Monitor, Oklahoma Department of Environmental Quality, Mississippi Public Utility Commission, Indiana Environmental Protection Agency, Michigan Department of Environment Quality, and the North American Electric Reliability Council 2000 Summer Assessment.

2.3.4 SO2 and NOx Emissions from Fossil-Fuel-Fired Generation

Sulfur Dioxide (SO2) and oxides of nitrogen (NOx) are emitted when electricity is produced through the burning of fossil fuels. SO2 and NOx (in combination) are precursors to acid rain.

On November 15, 1990, President Bush signed into law the Clean Air Act Amendments of 1990 (CAAA). Title 4 of the CAAA calls for a ten million-ton reduction in utility emissions of SO2 and a two million-ton reduction in NOx. The SO2 reduction was achieved in two phases. Phase 1 began on January 1, 1995, whereupon 265 generating units were required to reduce their emissions to a rate of 2.5 pounds of SO2/mmBtu (i.e., million Btus) multiplied by their average annual fuel consumption in Btus for the years 1985 through 1987 (the unit's "baseline"). Six Iowa units were affected under Phase I: Burlington Generating Station, Des Moines Energy Center Unit 7[29], George Neal Unit 1, M.L. Kapp Unit 2, Prairie Creek Unit 4, and Riverside Generating Station Unit 5. Phase II began on January 1, 2000, with all existing utility generating units required to reduce SO2 emissions to a level not to exceed 1.2 lbs/mmBtu multiplied by the unit's baseline. Phase II reduction levels are calculated so that total utility emissions never exceed approximately 8.9 million tons annually. This level of emissions is permanent, meaning that all new generating units cannot emit any SO2 unless

[29] The Des Moines Energy Center Unit 7 has since been retired and dismantled.

the owner acquires emission allowances from the allowance trading market or the United States Environmental Protection Agency (EPA).[30]

The CAAA also required unit owners and/or operators to install low NOx burners at each unit compatible with the technology. Units were required to comply with the CAAA's NOx requirements at the same time they were required to comply with the SO2 requirements.

Table 2-34 provides SO2 and NOx historical emission rates (in lbs/mmBtus) and tonnage from fossil-fuel-fired generation in Iowa. The table also provides annual heat input in Btus for the previous five years.

Table 2-34 Coal-Fired Unit Emissions

	1995	1996	1997	1998	1999	% Change 1995-1999
Annual Heat Input 10^{12} Btu	345.723	343.287	350.841	386.370	388.147	+ 12%
Annual NO_X Emissions (Tons)	84,189	79,159	75,090	81,081	80,283	- 5%
Annual NO_X Emission Rate (lb/mmBtu)	0.479	0.454	0.424	0.416	0.414	- 14%
Annual SO_2 Emissions (Tons)	175,595	151,528	155,645	171,733	156,075	- 11%
Annual SO_2 Emission Rate, (lb/mmBtu)	1.016	0.883	0.887	0.889	0.804	- 21%

Source: U.S. Environmental Protection Agency; Compiled by MidAmerican.

2.3.5 Generation Siting Requirements

The siting of new generation in the region depends, in part, on state rules and regulations governing certification. IOWA CODE 476A requires that a person shall not commence construction of an electric generating facility unless the Board has issued a certificate of public convenience, use, and necessity. Certification of all electric power generating plants or a combination of plants at a single site with a total nameplate capacity of 25 MW or more is required. The Board, if it determines that the public interest would not be adversely affected, may waive the certificate requirements for facilities with a capacity of up to 100 MW. A certificate is issued if the Board finds all of the following:

1. The services and operations resulting from the construction of the facility are required by the present or future public convenience, use, and necessity.

[30] The CAAA established a system by which utility emitters of SO2 can trade "allowances." An allowance is essentially an EPA-issued license to emit one annual ton of SO2. The owner(s) of new generating facilities must obtain allowances to offset new SO2 emissions or, alternatively, reduce generation from other sources that have been issued allowances.

2. The applicant is willing to perform such services and construct, maintain, and operate the facility pursuant to the provisions of the certificate.
3. The construction, maintenance, and operation of the facility will cause minimum adverse land use, environmental, and aesthetic impact and are consonant with reasonable utilization of air, land, and water resources for beneficial purposes considering available technology and the economics of available alternatives.
4. The applicant, if a utility, has a comprehensive energy management program.

A comprehensive energy management plan is not applicable to merchant plants which are non-utility generators where all or a portion of the electric output from the generating plant is sold into competitive electric markets and is not dependent upon long-term sales contracts with electric utilities.

IOWA CODE 476A also requires the applicants to meet permitting, licensing, and zoning requirements of other agencies. The Iowa Department of Natural Resources (IDNR) reviews all air construction permit applications to see if a source or modification may cause or contribute to a violation of the national ambient air quality standards. The IDNR rule 567 Iowa Administrative Code 22.1 requires "an air construction permit before installation, construction, or modification of any equipment or control equipment which emits regulated pollutants to the air outside of buildings."

New source performance standards apply to affected facilities and resources listed in IDNR rule 23.1(2). Some of the affected facilities in this list are: 1) electric utility steam generating units capable of combusting more than 250 MMBtu/hour (73 MW) heat input of fossil fuel in the steam generator; 2) an electric utility combined cycle gas turbine capable of combusting more than 250 MMBtu per hour; 3) industrial-commercial-institutional steam generating units with a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW; and 4) industrial-commercial-institutional steam generating units with a maximum design heat input capacity of 29 MW (100 MMBtu/hour) or less, but greater than or equal to 2.9 MW (10 MMBtu/hour).

IDNR rule 22.4 regulations require a Prevention of Significant Deterioration (PSD) permit. A PSD permit is required for large sources in the attainment areas.[31] A PSD permit requires the source use "the best available control technology." The level of air pollution control is determined on a case-by-case basis taking into account all costs and impacts to determine what is achievable for facility emission reductions. Fossil-fueled steam electric plants of more than 250 MMBtu/hour heat input and fossil-fuel boilers totaling more than 250 MMBtu/hour heat input require a PSD permit and are subject to a 100 tons per year threshold for air pollutants.

[31] Under PSD regulations, areas that have relatively clean air are referred to as attainment areas, or as being in attainment with the national ambient air quality standards. All of Iowa is currently in attainment except for one area near Muscatine.

3.0 DELIVERY SYSTEM CONDITIONS

Once electricity is produced, it must be delivered. This delivery is accomplished through transmission facilities (usually high-voltage lines connecting generating units or wholesale customers to the electric utility system) and distribution lines (usually low-voltage lines connecting retail customers to transmission facilities). The next subsection looks at the location of existing transmission and distribution facilities, as well as other infrastructure, needed to serve Iowa load. Data on the age of existing transmission and distribution facilities are also provided. Subsection 3.2 discusses the historical reliability of the delivery system and constraints on the transmission system. Subsection 3.3 discusses the future of Iowa's transmission and distribution facilities.

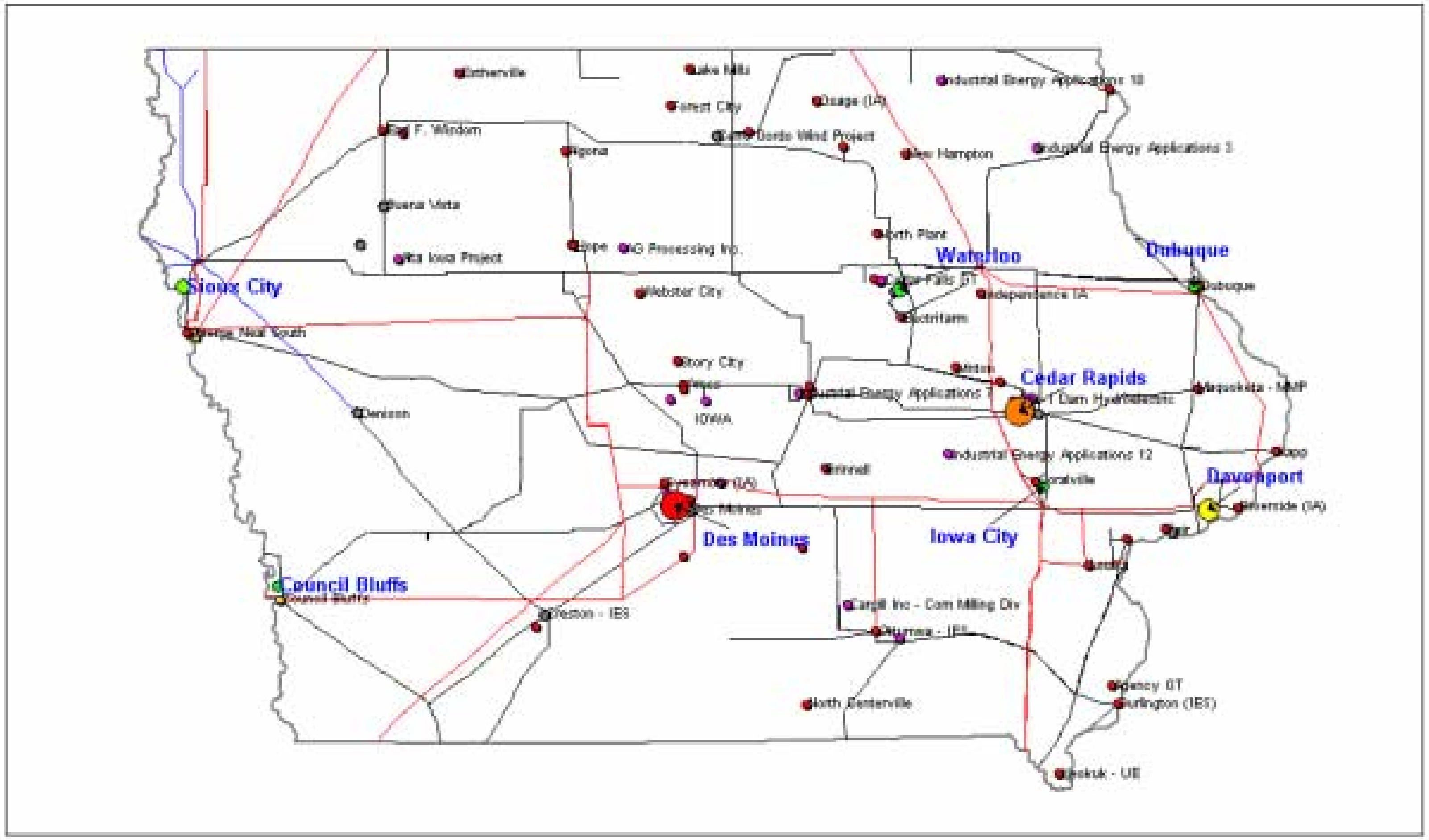
3.1 <u>Existing Transmission and Distribution Facilities</u>

3.1.1 Location of Facilities

Major factors affecting the location of generating facilities include access to: 1) major population (or load) centers, 2) fuel supplies, 3) transmission facilities, 4) water supplies, 5) environmental impacts, and 6) social considerations. **Figures 3-1 through 3-3** provide three maps showing the location of infrastructure needed to supply electricity to Iowa's consumers. **Figure 3-1** shows the location of major generating units, 115 kV to 345 kV transmission lines, and cities with population of over 50,000. **Figure 3-2** shows the location of major electric generating units, major natural gas pipelines, and cities with over 50,000 population. Pipelines are used to transport natural gas to generating units that burn natural gas as fuel. **Figure 3-3** shows the location of major electric generating units, rail lines, and cities with over 50,000 population. Rail lines are used to transport coal to generating units that burn coal as fuel.

Figure 3-1

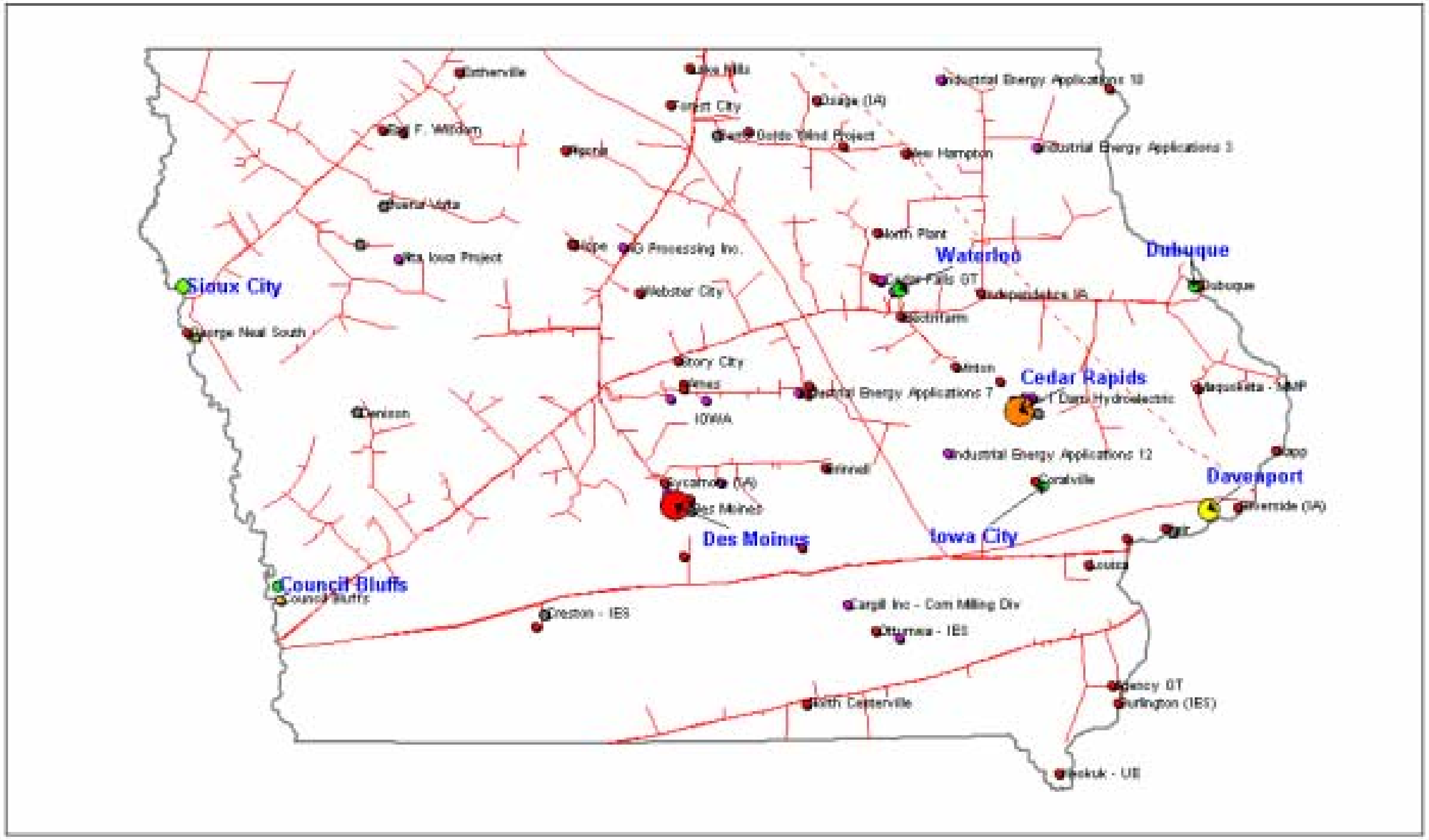
Iowa Electric Generation & Electric Transmission
With Cities over 50,000 Population



Source: RDI PowerMap

Figure 3-2

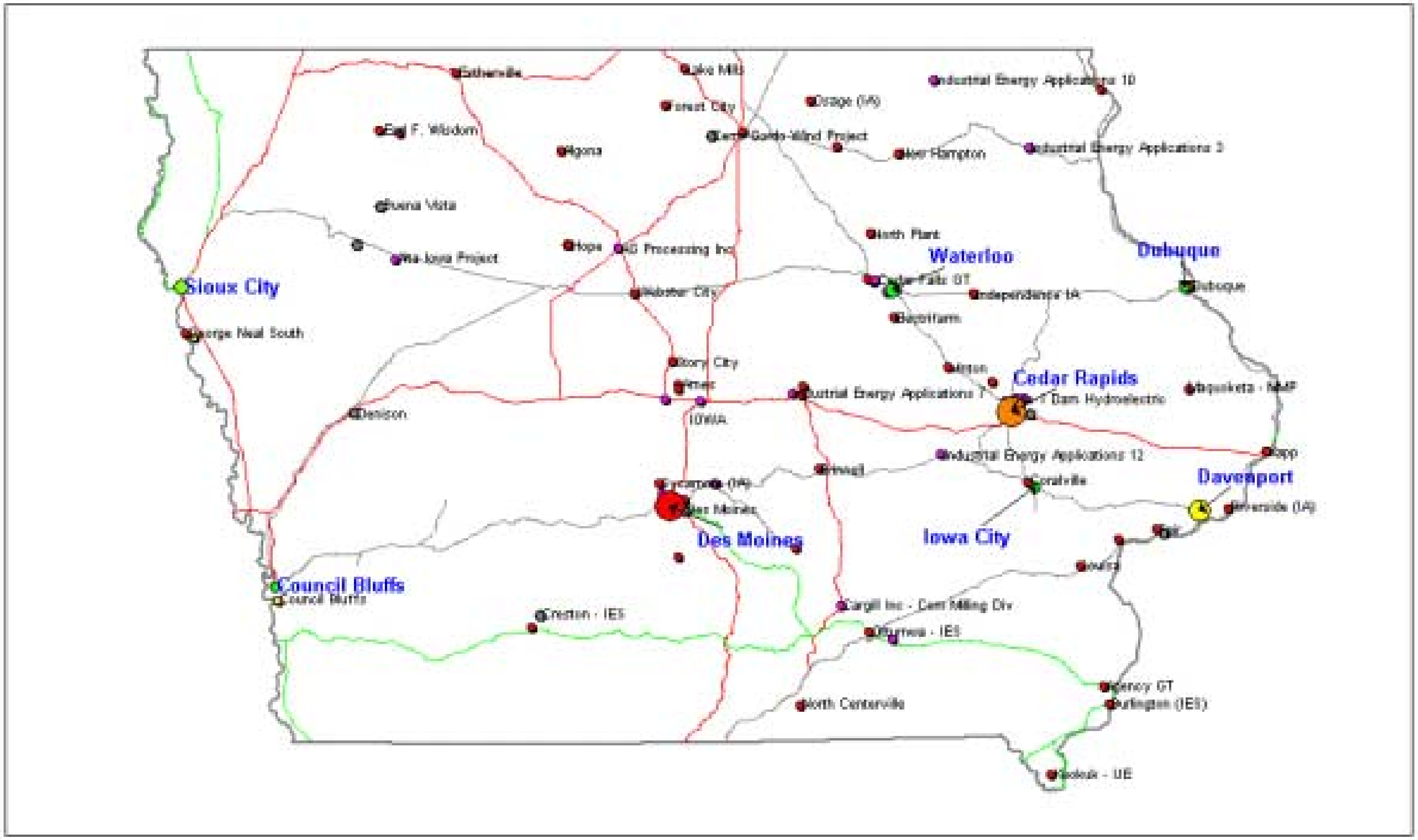
Iowa Electric Generation & Gas Pipelines
With Cities over 50,000 Population



Source: RDI PowerMap

Figure 3-3

Iowa Electric Generation & Rail Lines
With Cities over 50,000 Population



Source: RDI PowerMap

3.1.2 Age of Existing Facilities

Iowa's existing transmission and distribution systems have been constructed and operated since the early 1900's. The transmission and distribution facilities are operated at nominal voltages of 345 kV, 230 kV, 161 kV, 115 kV, 69 kV, 34.5 kV, 25 kV, 13 kV, and 4 kV.

The vintages of MidAmerican's and Alliant's transmission and distribution systems are provided in **Table 3-1** and **Figures 3-4 through 3-10**. The age of facilities in Table 3-1 corresponds to the dates when these facilities were originally built or completely rebuilt. Accounting records were used to determine the ages of facilities in the figures. Due to accounting procedures, these figures may underestimate the actual ages of facilities that remain in-service. A small percentage of these data include facilities outside of Iowa.

Table 3-1 provides information concerning the vintage of MidAmerican's and Alliant-IES' high voltage lines.

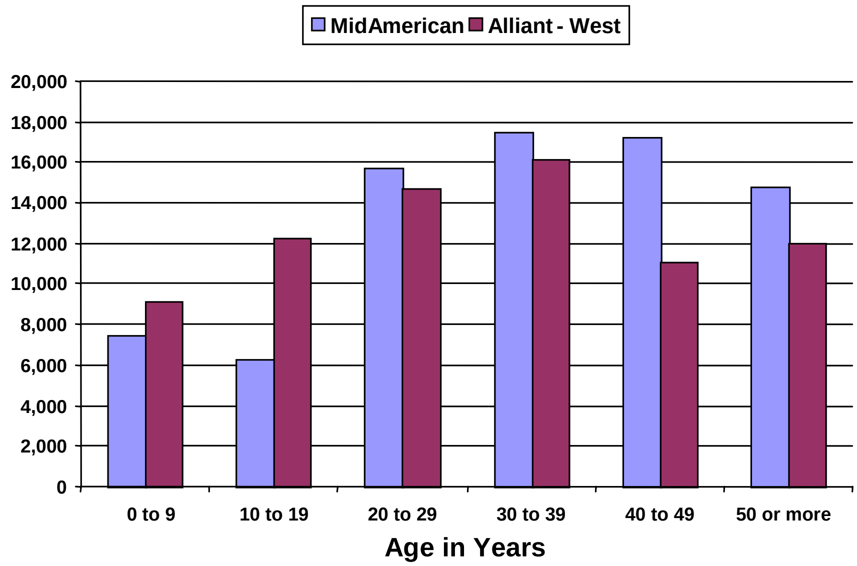
Table 3-1 Miles of Line by Age

Age in Years =>		0-9	10-19	20-29	30-39	40-49	50+	Total
345 kV	MidAmerican	125	109	173	489			896
	Alliant-West		36					36
161 kV	MidAmerican	70	36	169	268	490	268	1301
	Alliant-West	17	112	178	217			524
115 kV	MidAmerican							
	Alliant-West			3	25	215	133	376
69 kV	MidAmerican	128	175	416	495	389	175	1778
	Alliant-West	37	193	296	194	210	79	1009
34.5 kV	MidAmerican	16	9	19	1	50	125	220
	Alliant-West	117	216	391	464	410	662	2260

Notes: The total may exclude miles of line of unknown age. For MidAmerican, the age of 34.5 kV lines with 40 or more years of service is estimated. The numbers represent MidAmerican's and Alliant's equivalent share of jointly owned lines.
Sources: Information provided by MidAmerican and Alliant.

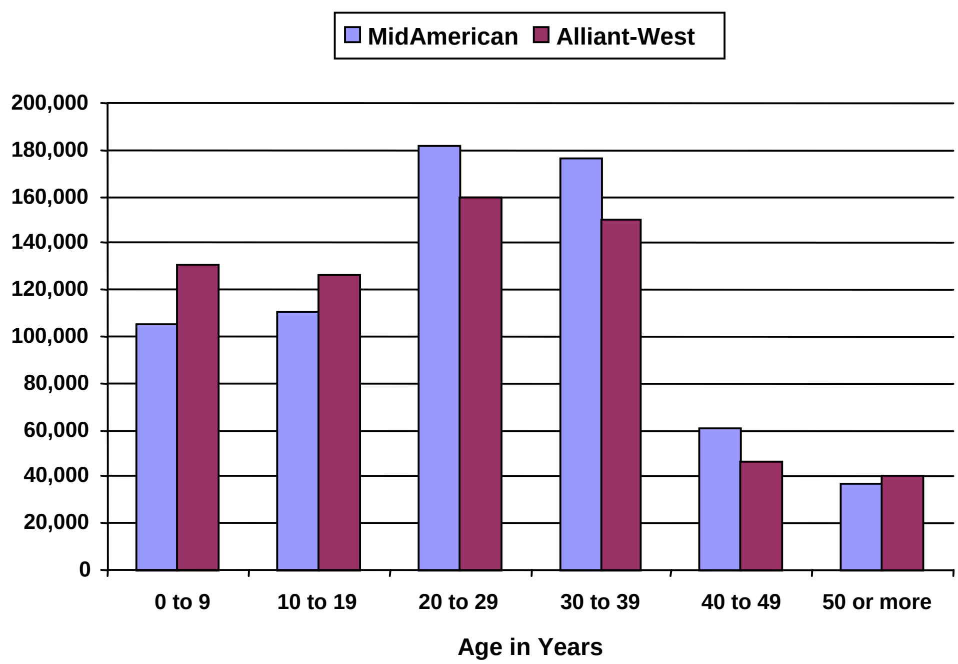
Figures 3-4, 3-5 and 3-6 provide vintages for poles and conductors for various voltage levels for MidAmerican and Alliant-IES. **Figures 3-7 and 3-8** provide the age of certain transformers for MidAmerican.

Figure 3-4 Number of Poles - 34.5 kV and Above



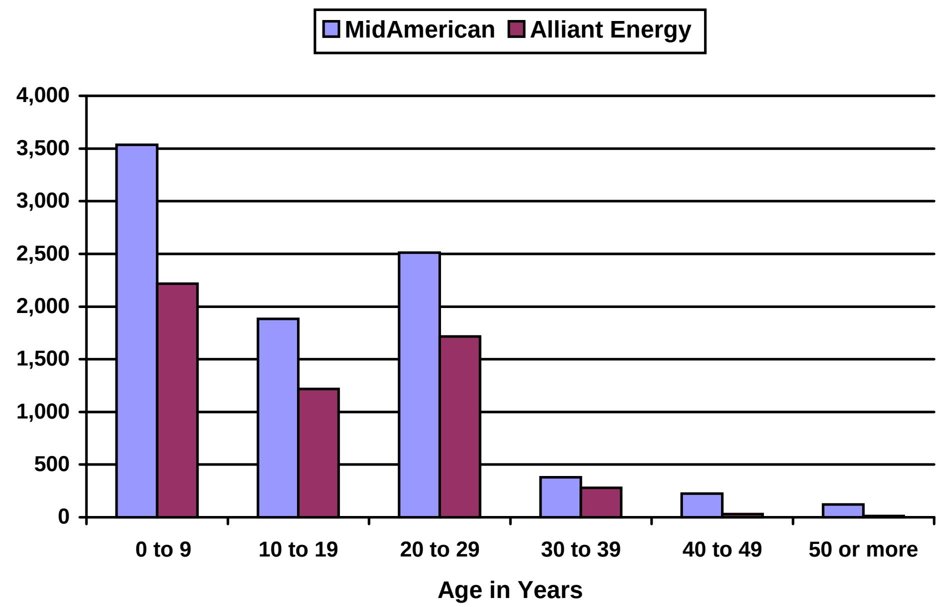
Sources: Information provided by MidAmerican and Alliant.

Figure 3-5 Number of Poles - 13 kV and Below



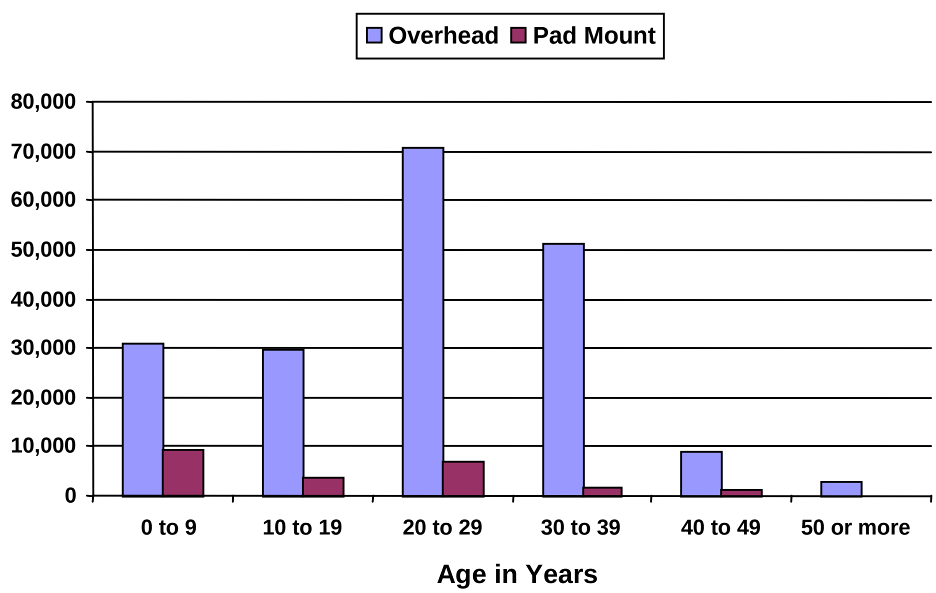
Sources: Information provided by MidAmerican and Alliant.

Figure 3-6 Miles of up to 13 kV Underground Conductor



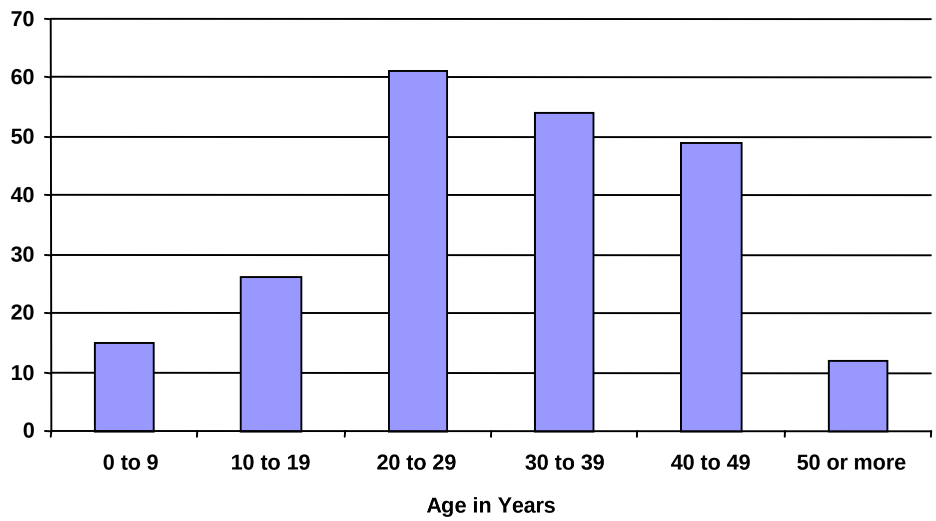
Source: Information provided by MidAmerican.

Figure 3-7 Number of MidAmerican Transformers - Up to 13 kV



Notes: This type of transformer is typically used to transform distribution circuit primary voltage to customer utilization voltage
Sources: Information provided by MidAmerican.

Figure 3-8 Number of MidAmerican Power Transformers



Notes: A power transformer transfers electric energy in any part of the circuit between the generator and the distribution primary circuits.
Sources: Information provided by MidAmerican.

Table 3-2 provides total pole miles for 345 kV, 161 kV, and 115 kV transmission lines solely owned by the RECs. While these data depict the year a line segment was constructed, the line may have been rebuilt, converted, reconductored, or upgraded since the time the line was originally constructed.

Table 3-2 115 kV/161 kV/345 kV Pole Miles Owned by RECs

Year of Construction	Pole miles		
	115 kV	161 kV	345 kV
1940-1949	0	60	0
1950-1959	43	84	0
1960-1969	0	184	0
1970-1979	0	26	0
1980-1989	5	188	0
1990-1999	20	13	7
Total	68	555	7

Source: Iowa Association of Electric Cooperatives

3.2 Reliability of Delivery Systems

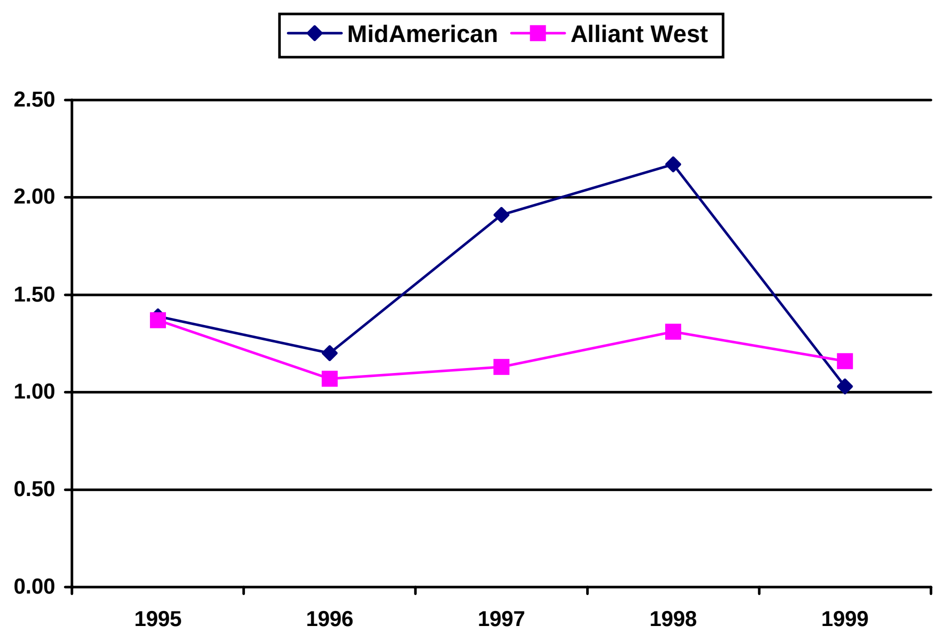
3.2.1 Reliability Indices

Reliability indices are used to indicate the reliability of electric service. These indices include:

- System Average Interruption Frequency Index (SAIFI) – SAIFI indicates the average number of service interruptions per customer. It is calculated as the ratio of the total number of customer interruptions to the total number of customers served.
- System Average Interruption Duration Index (SAIDI) – SAIDI indicates the average time that customers are interrupted. It is calculated as the ratio of the sum of customer interruption duration divided by the total number of customers served.
- Customer Average Interruption Duration Index (CAIDI) – CAIDI indicates the average time required to restore service to the average customer. It is calculated as the sum of customer interruption duration divided by the total number of interruptions.

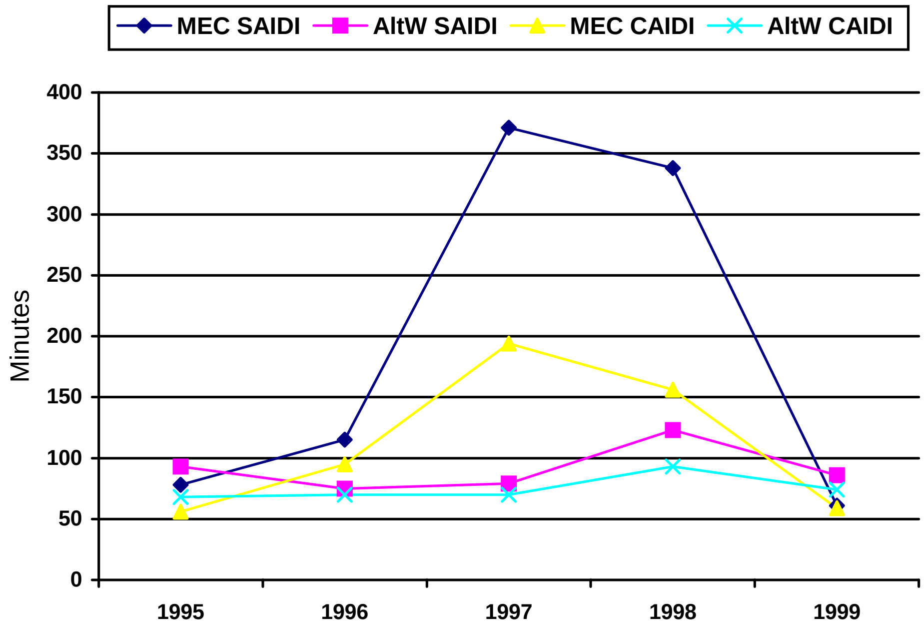
Figures 3-9 and 3-10 give the SAIFI, SAIDI, and CAIDI for MidAmerican and Alliant-West since 1995. These indices include portions of MidAmerican's and Alliant-West's systems located outside of Iowa. Outages due to storms and other major events are also included. The statistics are compiled from data available from automatic outage data systems that are not fully operational.

Figure 3-9 SAIFI



Notes: Differences in yearly indices are largely due to weather.
Sources: Information provided by MidAmerican and Alliant.

Figure 3-10 SAIDI and CAIDI



Notes: Differences in yearly indices and by utility are largely due to weather.
Source: Information provided by MidAmerican and Alliant.

Distribution automation (DA) has been evaluated and used sparingly by utilities for 25 years. Today DA is being widely used due to increased emphasis on reliability and power quality, along with reduced costs of data collection systems and communication systems. Remote control of distribution equipment and better customer outage reporting could materially affect CAIDI and SAIFI statistics and power quality.

3.2.2 Bulk Transmission System Outage Report

The MAPP Composite System Reliability Working Group issued a report in June 2000 entitled "Bulk Transmission System Outage Report." This report provides historical performance information for MAPP's 500 kV, 345 kV, and 230 kV systems for the 1990-1999 timeframe and for the year 1999 alone. The report indicates there were fewer 345 kV forced outages with shorter duration in 1999 compared to 1998. In 1999, the causes for forced outages were:[32]

Weather	62%
Terminal equipment failure	15%
Foreign interference	7%
Contamination	6%
Transmission line equipment failure	5%
Human error	5%

For 345 kV lines, there were more planned outages with shorter duration in 1999 as compared to 1998. Some of the major causes were:[33]

Transmission line maintenance	35%
Terminal maintenance	26%
Construction	14%

3.2.3 MAPP Constraints

Transmission facilities have limited capability, similar to generating units. When a transmission line reaches its capability it is considered "constrained." Constrained transmission interfaces limit the flow of power within the region and between regions.

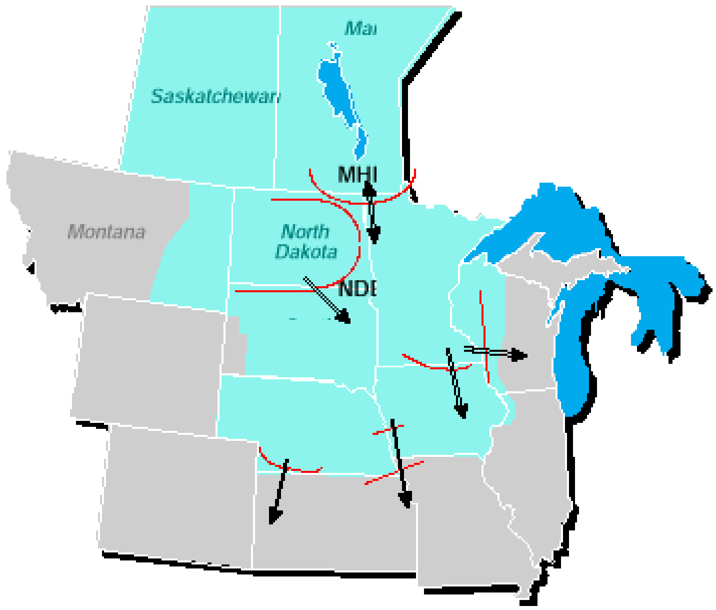
Power typically flows on Iowa's transmission system from Nebraska to the east and from Minnesota to the south across the state primarily due to the lower-cost generation in North Dakota, Nebraska, and MAPP-Canada. Also, there have been active power markets in MAIN and the Southwest Power Pool (SPP).

Figure 3-11 is a map of the current MAPP Constrained Interfaces.

[32] Forced outages refer to outages that were unplanned. Forced outages may relate to generating units, transmission, or distribution facilities.

[33] Planned outages refer to outages purposefully caused by the utility in order to perform maintenance or refuel (in the case of nuclear units).

Figure 3-11 MAPP Constrained Interfaces



Source: MAPP Regional Plan, 1996-2007, p.14.

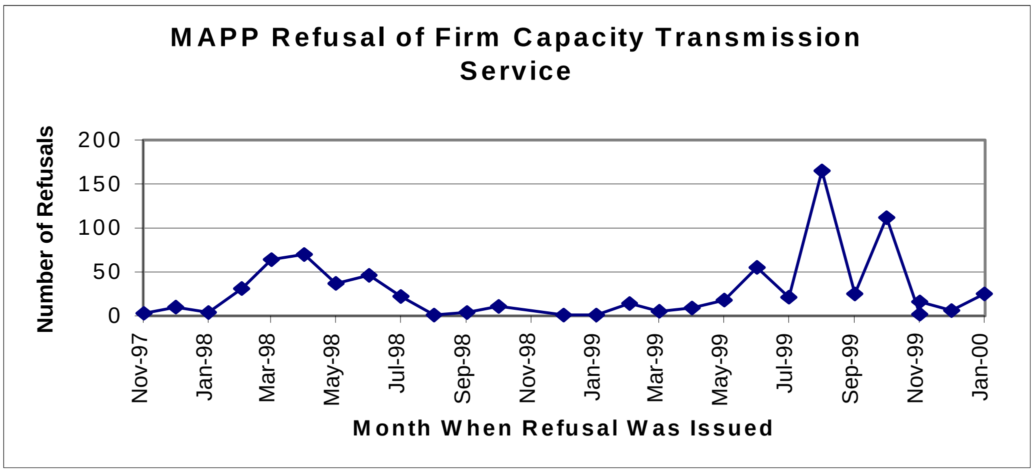
MAPP currently analyzes and approves regional transmission service requests that are less than two years in length. MAPP checks how transmission service requests impact transmission facilities that have been posted as MAPP Constrained Interfaces. These MAPP Constrained Interfaces have been calculated to only allow transmission service requests that will not exceed the known available transfer capability in a specific direction.

Two MAPP Constrained Interfaces that impact transmission flows across Iowa are Fort Calhoun South (north of the two constraints shown in **Figure 3-10** near the Nebraska/Iowa border) and the Eau Claire to Arpin interface (constraint shown in Figure 3-13 between Minnesota and Wisconsin). Fort Calhoun South generally impacts transmission service from northwest or north central Iowa to the south and east. Eau Claire to Arpin generally restricts transmission service from west to east. Eau Claire to Arpin impacts transmission service from points near or west of Waterloo and Cedar Rapids. This constraint is often referred to as the Minnesota to WUMS constraint. (WUMS refers to the Wisconsin-Upper Michigan System portion of MAIN).

Currently, Iowa's utilities do not report and monitor MAPP Constrained Interfaces. Transmission facilities outside of Iowa are more restrictive to transfers out of and through Iowa than transmission facilities within the state of Iowa. Alliant also uses the MAIN process for transmission service request analysis since Alliant belongs to the MAIN Reliability Council. Power flows in the MAIN region differ from those in the MAPP region. The MAPP region maintains a predominant direction of power flow throughout the year, while, in the MAIN region, the predominant power flow often changes directions.

Figure 3-12 provides Firm Capacity Transmission Service (FCTS) refusals by MAPP from November 1997 through January 2000. Refusals are made by priority group. Firm transmission service has priority over non-firm service. MAPP evaluates the impact of each transmission service request based on how the request affects all MAPP transmission interfaces.

Figure 3-12



Source: Information provided by MidAmerican.

Curtailments are also made by priority group with firm service given priority over non-firm service. A properly sized and operational transmission system should have few firm capacity curtailments unless the cost to relieve the constraints is too high. A highly constrained transmission system may have numerous firm curtailments.

3.2.4 Potential Constraints in Iowa

The Iowa Transmission Working Group's (ITWG's)[34] most recent Sub-Regional Transmission Plan identified the following 115 kV-161 kV facilities in Iowa as potential constraints to power transfers. These facilities typically constrain power transfers after MAPP constraints have already taken place. These facilities are monitored to ensure they do not become more limiting than transmission facilities located outside of Iowa.

[34] ITWG is made up of representatives from Iowa utilities that own transmission. The ITWG recommendations are combined with recommendations from other regional transmission working groups to form the MAPP regional transmission plan. A representative from the IUB staff typically attends the ITWG meetings.

⇒ Lime Creek – Emery 161 kV line (Alliant): This line was first identified in a recent study (not conducted by the ITWG) of the interface between MAPP and MAIN as a potential limiting element.

⇒ Council Bluffs - Bunge 161 kV line (MidAmerican): The Council Bluffs-Bunge 161 kV line has shown an overload under heavy power transfers during outage conditions. Under typical load conditions at Bunge, the line does not overload.

⇒ Clinton Area Facilities (Alliant): The Clinton Iowa area transmission system is identified as an area that needs review. The loading in this area, coupled with system transfers across Iowa to MAIN, can cause system violations.

⇒ Denison Area Facilities (Western Area Power Administration): Results from the contingency screening study indicate that overloads or low voltages of lower voltage elements occur in the Denison and Creston areas for single contingency outages of certain 230 and 161 kV elements. Transmission additions in the Denison area are planned in 2003.

⇒ Neal-Monona-Carroll-Grand Jct. 161 kV line (MidAmerican): Although not identified in the ITWG Sub-Regional Transmission Plan, this 161 kV line overloads under outage conditions and heavy power transfers. The Neal to Monona line section is equipped with line tension monitors that allow the rating of the line to be increased if the outside temperature is below the hottest temperatures of the summer.

3.3 Future of the State's Transmission and Distribution Systems

3.3.1 Scheduled Transmission System Construction

The most recent ITWG Sub-Regional Transmission plan lists planned transmission projects and upgrades. Based on current conditions, the ITWG study concluded that few additional problems occur for Iowa facilities sized at 100 kV and above over the next 10 years. The following projects (at 100 kV and above) are currently scheduled:

⇒ Twin Rivers to Viele 161 kV line (Alliant): This 161 kV, 12.5 mile line will be built by Alliant to increase reliability in the Keokuk, Iowa, region. The line will loop the existing radial 161 kV line that serves the area. The current in-service date for the line is May 1, 2003.

⇒ Salem-Mosalem-Eighth Street 161kV line: This 161 kV, eleven mile line will be built by Alliant in the Dubuque, Iowa, area to increase system security and reliability. Dubuque is currently served by a double circuit 161 kV line from Salem Substation. Loss of the double circuit can cause undesirable system operation. The addition of this line will maintain needed support from Salem Substation. The current in-service date for the line is May 1, 2003.

⇒ LeMars South 161/69 kV Substation and Plymouth to LeMars South 161 kV transmission line: This 161/69 kV substation will be built by MidAmerican. The substation will be located in the southeast corner of LeMars to serve projected load increases. The current in-service date for this substation and transmission line is June 1, 2001.

⇒ Marshalltown to Iowa Falls 115 kV Line Section: Alliant is scheduled to do several system upgrades in the Iowa Falls and Wellsburg area. Much of the 34.5 kV system in the Iowa Falls and Wellsburg area will be upgraded to 69 kV over the next 10 years.

3.3.2 Transmission Siting Requirements

IOWA CODE Chapter 478 requires a franchise from the IUB to construct, erect, maintain, or operate an electric transmission line capable of operating at 34,500 volts or more. To obtain a franchise, a petition containing route, design, and purpose data must be filed with the IUB. If over one mile of private property would be affected, a public information meeting must be held not less than 30 days before the petition is filed. Before granting a franchise, the IUB must find that the project is necessary to serve public use and bears a reasonable relationship to an overall plan of transmitting electricity in the public interest. The Board must also accept the proposed route, and may grant the right of eminent domain where necessary. Notice of the petition is published in a newspaper in the project area, and a public hearing is required if objections are filed or if the petitioner seeks the right of eminent domain.

3.3.3 Distributed Generation

Distributed generation is modular electric generation or storage located near the point of electric use. Distributed systems include biomass-based generators, combustion turbines, concentrating solar power and photovoltaic systems, fuel cells, wind turbines, microturbines, engine/generator sets, and storage and control technologies. Distributed generation may be used at decentralized locations across the transmission and distribution system. These generators can either be grid connected or operate independently of the grid. Distributed generation can reduce effective customer demand on the utility system and potentially export energy to the grid to compliment existing electric generation. Distributed generation can be customer- or utility-owned generation. Distributed generation technologies such as gas turbines, photovoltaics, wind, and fuel cells are becoming available at a higher level of efficiency and in smaller sizes. In contrast to large, central-station power plants, distributed power systems typically range from less than a kilowatt (kW) to tens of megawatts (MW) in size. The most pressing concern at the present time is the lack of national uniform technical standards for interconnecting distributed generation to the electric utility system. Work is underway by the Institute of Electrical and Electronics Engineers to develop a "Standard for Distributed Resources Connected to Electric Power Systems."

In April 2000, MidAmerican completed installation of 28 diesel generators with a capacity of 2 MW each to help meet peak load during the summer of 2000. Each generator, built by Caterpillar, is enclosed within a semi-trailer. In Iowa, MidAmerican installed these distributed generators at company-owned substations in Knoxville, Shenandoah, and Waterloo, where they connect into the electric grid.

3.3.4 Regional Reliability and Transmission Studies

MAPP 1998 Regional Plan and 1999 Update: MAPP prepared a regional transmission planning study for the period 1998 through 2007. The study proposed construction of several transmission facilities. The study focused primarily on local transmission problems. A major recommendation was to build a transmission line to improve the flow of power from the MAPP region into eastern Wisconsin. Twenty-one different transactions (or power transfers between pairs of electric supply and usage points) that experience constraints in the existing system were considered. The 1999 update to the plan considered 695 miles of transmission improvement. The majority of the addition consisted of two projects -- an Arrowhead (Duluth, Minnesota) to Weston (Wausau, Wisconsin) 345 kV line, and a Harvey (North Dakota) to Glenboro (Manitoba) 230 kV line. Most of the remaining transmission enhancements are required to ensure reliable transmission to serve load.

Wisconsin Interface Reliability Enhancement (WIRE) Study: In 1998 and 1999, a group consisting primarily of Wisconsin utilities studied Wisconsin's future power import capability known as the WIRE study. The study focused on the summer of 2002 and identified several transmission improvements that could increase power import capability into Wisconsin to 3000 MW. The imports would come from MAPP and Illinois utilities. The study also concluded that already-planned construction could improve the import capability up to 2000 MW, but would not eliminate concerns regarding operational limits of some existing lines.

The second phase of the project studied a sub-set of the phase-one lines in detail. The study formed the basis to build a transmission line from Arrowhead substation in Duluth to the Weston power plant near Wausau. Minnesota and Wisconsin regulators are currently considering the application for this line.

4.0 Customer Service

Customer service primarily refers to billing, metering, and customer contact. This section of the report provides a brief description of recent changes in billing, metering, and outage reporting systems used by the IOUs, the RECs, and the municipal utilities.

4.1 Billing Systems

Technological changes in the U.S. economy are changing the manner in which businesses bill their customers for the services they provide. Technological changes are also having an impact on customer access to the data points that are used in the billing process and the billing medium (i.e., paper or electronic).

Alliant*:* Alliant is considering implementation of a front-end enterprise application that will allow it to access data, regardless of the legacy system that houses the data. Once the front-end implementation is in place, this tool will enable Alliant-West to select and install customer billing applications/systems to meet billing needs in a changing industry. Alliant Energy will begin the functional analysis early next year, with system selection and implementation to follow. Alliant's current systems are able to bill for gas, electric and steam commodity, and a minimal level of other services.

MidAmerican*:* MidAmerican implemented a new Customer Service System (CSS) in November 1998. The new system replaced legacy systems. The conversion process took approximately two years and was a collaborative effort between Anderson Consulting, MidAmerican's Information Technology Department, and subject matter experts from MidAmerican's customer service, accounting, and other departments. CSS has the capability of billing gas, electricity, lighting, and any non-service product offered by the MidAmerican. CSS currently bills over 1.2 million service points each month and has the ability to bill several times that amount. Scalability is limited only by the current processor capacity and disk space.

RECs*:* Many of Iowa's RECs outsource some or all of the services related to billing. This is accomplished primarily to achieve economies of scale, to leverage investment in technological changes, and to leverage experts in computer programming. Electronic billing via the internet is another option that is being considered by several RECs.

Municipals: Consumers of Iowa's municipals are billed utilizing either a paper bill mailed within an envelope or a postcard type bill. The systems supporting these billing processes vary from utility to utility. Some utilities utilize their own billing systems and processes while other utilities use a wide variety of systems and processes. Electronic billing is an option that is being investigated by some municipals.

4.2 Metering

Alliant: The Alliant meter reading functions are managed as part of its customer care organization. This organization houses customer information and manages customer contact. Alliant is currently assessing and expanding the use of metering technology. Alliant currently uses hand-held devices for meter reading and has implemented some pilot automated meter reading (AMR) programs. A web-enabled information center at the customer premise is an option being explored.

MidAmerican: MidAmerican has approximately 600,000 meters installed within Iowa. Approximately 90 percent of those meters are residential installations. Meter information is collected through various technologies such as handheld computers, radio technology, and power-line-carrier. MidAmerican presents meter information on the internet via a web site and is looking to expand those capabilities. Additionally, AMR technology has been studied and will be pursued if a solid business case presents itself.

RECs: Iowa's RECs have meters in all 99 counties of Iowa. Meter data are collected using a variety of processes, varying from AMR technologies to handheld meter reading devices to allow member-consumers the option to read their meter. Most of Iowa's RECs have either deployed AMR technologies or are in the process of implementing or investigating various AMR systems. Changes in metering practices are dependent on customer acceptance of such practices.

Municipals: Iowa municipal electric utilities serve nearly 200,000 customers or meters. A variety of hand-held and automated meter reading systems are in-place among municipal utilities.

4.3 Automatic Outage Reporting

Alliant Energy**:** Alliant's Distribution Management System (DMS) analyzes outages on the distribution system and aids in the development of switching plans. The system uses incoming calls generated from within the Customer Information System to conduct the outage analysis. The application calculates the probable outage device based on the location of the incident(s) on the electric system. As more trouble calls are received, the application will automatically recalculate the probable outage device based on the outage analysis rules. Once the outage is confirmed and service is restored, a callback list is generated for the customer service consultants to verify the service has been restored. Also, when an outage is confirmed, the dispatcher may enter the cause and estimated restoration time. This information is entered into all affected customers' account histories. This provides consultants near real time information as well as historical information for individual customers. Outage data is collected and archived within a reporting tool. The reporting tool provides a restored outage history and allows outages to be reviewed and filtered in a variety of ways for additional analysis (i.e., outage type, outage ID, cause, substation, feeder number, etc.). The DMS also aids in the development of switching plans. Plans may be submitted within a test mode to help determine validity and flag any operational concerns.

***MidAmerican*:** MidAmerican's Electric Outage Management System (EOMS) provides both real-time and historical customer outage information. Outage data collected include location, cause, start date and time, end date and time, and customers affected. The real-time and historical outage statistics may be interrogated and summarized by district, service center, substation, circuit, or customer. This allows for calculation of both frequency and duration of outage related statistics. The data collected are based upon incoming customer calls. In real time, the EOMS system aids the outage restoration process as it automatically groups associated customer outages together to determine the location of the device that opened. A summary of outage orders and the status or such orders is displayed on-line. As each order progresses through the various stages (order assigned, crew dispatched, crew arrives on site, estimated service restoration, actual service restoration, and order completed), dates and times are entered for each stage and displayed on-line. As orders are completed, the outage occurrence, cause, action taken, and any crew remarks are noted and become part of the outage history. This provides the customer service associates both real time and historical information.

RECs: Some RECs have undertaken a distribution automation project called Supervisory Control and Data Acquisition. When completed, this system will allow monitoring and control from the central office of many substations, substation devices, and line switching applications. This monitoring will allow operators to view information in the field without dispatching a crew. The control aspect will allow some protective devices to be controlled in the office so, when an outage occurs, the problem can be resolved in a much quicker manner. Line crews can fix the problem without going back to the substation to reactivate the protective device. The system will also provide more detailed information for planning and targeting system upgrades.

Cooperatives that borrow money from Rural Utility Service (RUS--formerly REA) are required to annually report certain data regarding outages. Because of the small number of consumers, physical locale to the member, the inherent accountability to the member-consumer, and the accountability to RUS, many cooperatives have relied on more traditional processes of outage reporting.

List of Acronyms

AEP – Alternate Energy Production

AMR – Automated Meter Reading

Btu – British Thermal Unit

CAAA – Clean Air Act Amendments

CAIDI – Customer Average Interruption Duration Index

DMS – Distribution Management System

EIA – Energy Information Administration

EOMS – Electric Outage Management System

EPACT – Energy Policy Act

FCTS – Firm Capacity Transmission Service

FERC - Federal Energy Regulatory Commission

FPA - Federal Power Act

G&T - Generation and Transmission Cooperative

GW – Gigawatt

GWh – Gigawatt Hour

IAC - Iowa Administrative Code

IAEC - Iowa Association of Electric Cooperatives

IAMU - Iowa Association of Municipal Utilities

IDNR – Iowa Department of Natural Resources

IESC - Iowa Electrical Safety Code

ITWG – Iowa Transmission Working Group

IUB – Iowa Utilities Board

IOU - Investor-Owned Utility

ISO - Independent System Operator

IES - IES Utilities Inc.

KV - Kilovolt

kW - Kilowatt

kWh – Kilowatt Hour

LC – Load Control

List of Acronyms Continued

MAIN - Mid-American Interconnected Network

MAPP - Mid-Continent Area Power Pool

MEC – MidAmerican Energy Company

MISO – Midwest Independent System Operation

MW – Megawatt

MWh – Megawatt Hour

NERC - North American Electric Reliability Council

NIMECA – North Iowa Municipal Electric Cooperative Association

NIPCO - Northwest Iowa Power Cooperative

NOx – Oxides of Nitrogen

OMS - Outage Management System

PBR - Performance-Based Regulation

PDS – Prevention of Significant Deterioration

PJM – Pennsylvania, New Jersey, Maryland Power Pool

PUC - Public Utilities Commission

REA – Rural Electric Association

REC - Rural Electric Cooperative

RTO – Regional Transmission Organization

RUS – Rural Utility Service

SAIDI – System Average Interruption Duration Index

SAIFI – System Average Interruption Frequency Index

SIMECA – South Iowa Municipal Electric Cooperative Association

SO2 – Sulfur Dioxide

SPP – Southwest Power Pool

WAPA – Western Area Power Administration

WIRE – Wisconsin Interface Reliability Enhancement

WUMS – Wisconsin-Upper Michigan System

WPL – Wisconsin Power and Light

Glossary of Terms

Alternative Energy Producer (AEP) – An AEP is an electric facility that derives 75 percent or more of its energy input from solar energy, wind, hydro, waste management, resource recovery, refuse-derived fuel, agricultural crops or residues, or wood.

Base Load Capacity – Base-load units run near full capacity continuously day and night, all year long. Base-load units have high first costs and low fuel costs. Typically coal fired, nuclear, and hydroelectric units are base-load units.

Billing Services – Billing and collection for delivery services.

Bulk Power Market – Power transactions among utilities, or from a Wholesale Power Supply Provider to a Delivery Service Provider, power marketer or broker, or other wholesale entity.

Bulk Power System – The electrical system consisting of generation and the interconnected transmission system that moves bulk power to distribution or delivery systems.

Bulk Power System Reliability – There are two aspects of bulk power system reliability: adequacy and security. Adequacy is the ability of the electric system to supply the demand and energy requirements of the End-Use Consumers at all times, taking into account all outages of system elements. Security is the ability of the system to withstand sudden disturbances.

Curtailment – A reduction in the scheduled capacity or energy.

Customer – A person that consumes or uses electric energy.

Demand – Electric power measured in kilowatts.

Deregulation – The elimination of regulation from a previously regulated industry or sector of an industry.

Distribution Service – Electricity service provided over low-voltage lines to retail consumers.

Economic Dispatch – Distribution of total generation requirements among alternative generator sources for optimum system economy taking into account both incremental generating costs and incremental transmission costs.

Electric Cooperative – An electric utility service provider formed or organized as an Electric Cooperative under the laws of Iowa or elsewhere.

Glossary of Terms Continued

<u>Energy</u> – Electic energy measured in kilowatt-hours (kWh).

<u>FERC</u> – The Federal Energy Regulatory Commission (FERC) regulates wholesale power and transmission services.

<u>Firm Power</u> – Power which is intended to have assured availability to the End – Use Consumer to meet all or any agreed-upon portion of his load requirements.

<u>Generation and Transmission Electric Cooperative (G&T)</u> – A non-profit corporation, owned and controlled by Rural Electric Cooperatives (RECs) providing distribution service, that supplies wholesale power and transmission services to its members.

<u>Independent System Operator (ISO)</u> – An ISO is an independent entity that polices, monitors, and has overall decision-making authority over electric transmission operations. The purpose of an ISO is to provide reasonable and equitable access to the transmission system, to operate the transmission system safely and reliably, and to prevent the transmission system from becoming a factor in enhancing market power in an electricity market.

<u>Interconnected System</u> -- A system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

<u>Interface</u> -- The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.

<u>Intermediate Load Capacity</u> -- Intermediate load units fit between base load capacity and peaking capacity in both first costs and fuel costs. Intermediate load units are 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 in order to take the load swings on the system. Older smaller base-load units and hydro units with restrictions on water use are some times used as intermediate units. Natural gas and oil fired units are also used as intermediate units.

<u>Load Factor</u> – The average load of a customer, a group of customers, or the system divided by the maximum load. For example, assuming 48 kWh of usage for the day, the average load is 48/24 or 2 KW. If the maximum load is 4 KW, the load factor is 2/4 = 50 percent.

<u>Municipal Utility</u> – A city enterprise engaged in the production, delivery, service, or sales of energy established pursuant to Code of Iowa Chapter 388. Municipal Utility includes a combined utility system.

<u>Power Transformer</u> – A power transformer transfers electric energy in any part of the circuit between the generator and the distribution primary circuits.

Glossary of Terms Continued

Peaking Capacity – Peaking units are run only during daily peak load periods during seasonal peak times and during emergencies. Peaking units generally have low first and high fuel costs. Combustion turbines and pumped-storage hydro units are the typical peaking units.

Tie Line - A circuit connecting two or more control areas or systems of an electric system.

Time-of-Day Rate Structure – A rate structure that allows the price of electricity to the end-user to change at predetermined intervals (e.g., every half-hour) through out the day.

Transformer (up to 13 kV) – Transformer is an electric device, which when used, will raise or lower the voltage of alternating current of the original source. This type of transformer is typically used to transform distribution circuit primary voltage to customer utilization voltage.

Transmission Grid (System) – An interconnected group of electric transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points of delivery.

Transmission-Line Capacity – The maximum continuous rating of a transmission line. The rating may be limited by thermal considerations, capacity of associated equipment, voltage regulation, system stability, or other factors.

Transmission-Line Constraint – Limits on the transmission line because of physical or system requirements.

Utility – A person owning or operating facilities for furnishing electric services to the public for compensation and subject to rate or service jurisdiction of the Board pursuant to Code of Iowa Chapter 476.

LIST OF APPENDICES

APPENDIX A
IOWA'S RURAL ELECTRIC COOPERATIVES

Associated Electric Cooperative, Inc

Provides wholesale power to six regional member systems that in turn provide service to 51 local electric cooperative systems in Missouri, southeast Iowa and northeast Oklahoma. Three of the 51 are Iowa-based distribution systems that are served from one of the six regional member systems of Associated. The Regional system that serves the three Iowa distribution systems is Northeast Missouri Electric Co-op (NEMO) (three Iowa based member distribution systems and five Missouri based member distribution systems).
Headquarters: Springfield, Missouri

- Northeast Missouri Electric Cooperative, Palmyra, Missouri.
  - Southern Iowa Electric Cooperative (Bloomfield, Iowa)
  - Southeast Iowa Electric Cooperative (Mt. Pleasant, Iowa)
  - Chariton Valley Electric Cooperative (Albia, Iowa)

Basin Electric Power Cooperative

Ten G&T member systems (Two in Iowa)
Headquarters: Bismarck, N.D.

- Northwest Iowa Power Cooperative, Le Mars, Iowa
  - Harrison County Rural Electric Cooperative (Woodbine, Iowa)
  - Iowa Lakes Electric Cooperative (Estherville, Iowa)
  - Nishnabotna Valley Rural Electric Cooperative (Harlan, Iowa)
  - North West Rural Electric Cooperative (Le Mars, Iowa)
  - Western Iowa Municipal Electric Cooperative Association (Manning, Iowa)
    - *Anthon Municipal Utility*
    - *Aurelia Municipal Electric Utility*
    - *Hinton Municipal Electric*
    - *Manning Municipal Light Plant*
    - *Mapleton Municipal Electric*
    - *Onawa Municipal Electric Light Plant*
  - Western Iowa Power Cooperative (Denison, Iowa)
  - Woodbury Rural Electric Cooperative (Moville, Iowa)
- L&O Power Cooperative, Rock Rapids, Iowa
  - Lyon REC (Rock Rapids, Iowa)
  - Osceola Electric Co-op Inc. (Sibley, Iowa)

APPENDIX A CONTINUED

Central Iowa Power Cooperative

13 member distribution systems and one Municipal Electric Cooperative Association
Headquarters: Cedar Rapids, Iowa

- Clarke Electric Cooperative (Osceola, Iowa)
- Consumers Energy (Marshalltown, Iowa)
- East-Central Iowa REC (Urbana, Iowa)
- Eastern Iowa Light and Power Cooperative (Wilton, Iowa)
- Farmers Electric Cooperative (Greenfield, Iowa)
- Linn County REC (Marion, Iowa)
- Maquoketa Valley Electric Cooperative (Anamosa, Iowa)
- Midland Power Cooperative (Jefferson, Iowa)
- Pella Cooperative Electric Assn. (Pella, Iowa)
- Rideta Electric Cooperative (Mt. Ayr, Iowa)
- Southern Iowa Municipal Electric Cooperative Association (SIMECA)
  - *Brooklyn Municipal Utilities*
  - *Cascade Municipal Utilities*
  - *Corning Municipal Utilities*
  - *Earlville Municipal Utilities*
  - *Fontanelle Municipal Utilities*
  - *Gowrie Municipal Utilities*
  - *Greenfield Municipal Utilities*
  - *Lamoni Municipal Utilities*
  - *Lenox Municipal Utilities*
  - *Stuart Municipal Utilities*
  - *Villisca Municipal Power Plant*
- Southwest Iowa Service Cooperative (Stanton, Iowa)
- TIP REC (Brooklyn, Iowa)

Dairyland Power Cooperative

Three Iowa member distribution systems and 18 Wisconsin member distribution systems, three Minnesota member distribution systems and one Illinois member distribution system
Headquarters: La Crosse Wis.

- Allamakee-Clayton Electric Co-op (Postville, Iowa)
- Hawkeye Tri-County REC (Cresco, Iowa)
- Heartland Power Cooperative (Offices in St. Ansgar and Thompson, Iowa)

Corn Belt Power Cooperative

11 member distribution systems and one Municipal Electric Cooperative Association
Headquarters: Humboldt, Iowa

- Boone Valley Electric Co-op (Renwick, Iowa)
- Butler County REC (Allison, Iowa)
- Calhoun County Electric Co-op (Rockwell City, Iowa)
- Franklin REC (Hampton, Iowa)
- Glidden REC (Glidden, Iowa)
- Grundy County REC (Grundy Center, Iowa)
- Humboldt County REC (Humboldt, Iowa)
- Iowa Lakes Electric Co-op (Estherville, Iowa)
- Midland Power Cooperative (Jefferson, Iowa)
- North Iowa Municipal Electric Cooperative Association (NIMECA)
  - *Alta Municipal Power Plant*
  - *Bancroft Municipal Utilities*
  - *Coon Rapids Municipal Utilities*
  - *Graettinger Municipal Utilities*
  - *Municipal Light and Power (Grundy Center)*
  - *Municipal Light and Power Plant (Laurans)*
  - *Milford Municipal Utilities*
  - *New Hampton Municipal Light Plant*
  - *Spencer Municipal Utilities*
  - *Sumner Municipal Light Plant*
  - *City of Webster City*
  - *West Bend Municipal Utilities*
- Prairie Energy Cooperative (Offices in Garner & Clarion)
- Sac County REC (Sac City, Iowa)

Iowa also has some consumers who are served by distribution electric cooperatives that have their headquarters in other states and serve a small percentage of their member-consumers in Iowa. These cooperatives are as follows: Atchison-Holt Electric Cooperative (Rock Port, Missouri), Federated Rural Electric Cooperative Association (Jackson, Minnesota), Freeborn-Mower Electric Cooperative (Albert Lea, Minnesota), Grundy Electric Cooperative (Trenton, Missouri), Nobles Electric Cooperative (Worthington, Minnesota), Tri-County Electric Cooperative (Rushford, Minnesota) and United Electric Cooperative (Maryville, Missouri).

Cooperative distribution systems not associated with a particular G&T cooperative include Pleasant Hill Community Line (Webster City, Iowa) and Farmers Electric Cooperative (Kalona, Iowa).

APPENDIX B – IOWA'S MUNICIPAL UTILITIES

1. Afton City of
2. Akron City of
3. Algona City of
4. Alta City of
5. Alta Vista City of
6. Alton City of
7. Ames City of
8. Anita City of
9. Anthon City of
10. Aplington City of
11. Atlantic City of
12. Auburn City of
13. Aurelia City of
14. Bancroft Municipal Utilities
15. Bellevue City of
16. Bloomfield City of
17. Breda City of
18. Brooklyn City of
19. Buffalo City of
20. Burt City of
21. Callender City of
22. Carlisle City of
23. Cascade City of
24. Cedar Falls City of
25. Coggon City of
26. Coon Rapids City of
27. Corning City of
28. Corwith City of
29. Danville City of
30. Dayton City of
31. Denison City of
32. Denver City of
33. Dike City of
34. Durant City of
35. Dysart City of
36. Earlville City of
37. Eldridge City of
38. Ellsworth City of
39. Estherville City of
40. Fairbank City of
41. Farnhamville City of
42. Fonda City of
43. Fontanelle City of
44. Forest City City of
45. Fredericksburg City of
46. Glidden City of
47. Gowrie City of
48. Graettinger City of
49. Grafton City of
50. Grand Junction City of
51. Greenfield City of
52. Grundy Center City of
53. Guttenberg City of
54. Harlan City of
55. Hartley City of
56. Hawarden City of
57. Hinton City of
58. Hopkinton City of
59. Hudson City of
60. Independence City of
61. Indianola City of
62. Keosauqua City of
63. Kimballton City of
64. La Porte City City of
65. Lake Mills City of
66. Lake Park City of
67. Lake View City of
68. Lamoni City of
69. Larchwood City of
70. Laurens City of
71. Lawler City of
72. Lehigh City of
73. Lenox City of
74. Livermore City of
75. Long Grove City of
76. Manilla Town of
77. Manning City of
78. Mapleton City of
79. Maquoketa City of
80. Marathon City of
81. McGregor City of
82. Milford City of
83. Montezuma City of
84. Mt Pleasant City of
85. Muscatine City of
86. Neola City of
87. New Hampton City of
88. New London Municipal Utilities
89. Ogden City of
90. Onawa City of
91. Orange City City of
92. Orient City of
93. Osage City of
94. Panora City of
95. Paton City of
96. Paullina City of
97. Pella City of
98. Pocahontas City of
99 Preston City of
100. Primghar City of
101. Readlyn City of
102. Remsen City of
103. Renwick City of
104. Rock Rapids City of
105. Rockford City of
106. Sabula City of
107. Sanborn City of
108. Sergeant Bluff City of
109. Shelby City of
110. Sibley City of
111. Sioux Center City of
112. Spencer City of
113. Stanhope City of
114. Stanton City of
115. State Center City of
116. Story City City of
117. Stratford City of
118. Strawberry Point City of
119. Stuart City of
120. Sumner City of
121. Tennant City of
122. Tipton City of
123. Traer City of
124. Villisca City of
125. Vinton City of
126. Wall Lake City of
127. Waverly City of
128. Webster City City of
129. West Bend City of
130. West Liberty City of
131. West Point City of
132. Westfield Town of
133. Whittemore City of
134. Wilton City of
135. Winterset City of
136. Woodbine City of
137. Woolstock City of

APPENDIX C

INVESTOR-OWNED UTILITY REPORTING TO MAPP

MidAmerican:

The following utilities are included in MidAmerican's 1999 MAPP reporting:

Alta City of
Bancroft City of
Bancroft Municipal Utilities
Cedar Falls City of
Coon Rapids City of
Corn Belt Power Cooperative*
Geneseo City of
Graettinger City of
Grundy Center City of
Indianola City of
Iowa-Illinois Gas & Electric Company
Laurens City of
MidAmerican Energy Company
Midwest Power Systems, Incorporated
Milford City of
Montezuma City of
New Hampton Village Precinct
Spencer City of
Sumner City of
Waverly City of
Waverly Municipal Electric Utility
Webster City City of
West Bend City of

Alliant:

Alliant reported for the following utilities in its 1999 MAPP reporting:

IES Utilities
Interstate Power Company
Central Iowa Power Cooperative*

*Central Iowa Power Cooperative and Corn Belt Power Cooperative include their associated member systems.

APPENDIX D
IOWA UTILITY GENERATORS

Utility Name	Plant Name	Prime Mover	Fuel Type	Capacity MW*
Algona Municipal Utilities	Neal (IA)	STEAM	COAL	18.35
Algona Municipal Utilities	Algona	INT COMB	OIL	0.6
Algona Municipal Utilities	Algona	INT COMB	OIL	0.8
Algona Municipal Utilities	Algona	INT COMB	OIL	1.1
Algona Municipal Utilities	Algona	INT COMB	OIL	3.2
Algona Municipal Utilities	Algona	INT COMB	OIL	4.1
Algona Municipal Utilities	Algona	INT COMB	OIL	4.4
Algona Municipal Utilities	Algona	INT COMB	OIL	4.4
Algona Municipal Utilities	George Neal South	STEAM	COAL	18.35
Alta Municipal Power Plant	Alta (ALTA)	INT COMB	OIL	0.95
Alta Municipal Power Plant	Alta (ALTA)	INT COMB	OIL	1
Ames Municipal Electric System	Ames-Gt	GAS TURB	OIL	16
Ames Municipal Electric System	Ames	STEAM	COAL	35
Ames Municipal Electric System	Ames	STEAM	COAL	68
Atlantic Municipal Utilities	Atlantic (ATLAN)	INT COMB	GAS	4
Atlantic Municipal Utilities	Council Bluffs	STEAM	COAL	15.93
Bancroft Municipal Electric Plant	Neal (IA)	STEAM	COAL	2.18
Bancroft Municipal Electric Plant	George Neal South	STEAM	COAL	2.18
Bellevue Municipal Utilities	Bellevue	INT COMB	OIL	0.53
Bellevue Municipal Utilities	Bellevue	INT COMB	OIL	0.6
Bellevue Municipal Utilities	Bellevue	INT COMB	OIL	0.75
Bellevue Municipal Utilities	Bellevue	INT COMB	OIL	2.4
Bellevue Municipal Utilities	Bellevue	INT COMB	OIL	1.6

APPENDIX D CONTINUED

Cascade Electric & Gas Dept.	Cascade (CASC)	INT COMB	OIL	1.86
Cedar Falls Utilities	Neal (IA)	STEAM	COAL	15.6
Cedar Falls Utilities	Streeter Station	STEAM	COAL	19.95
Cedar Falls Utilities	Streeter Station	STEAM	COAL	36.6
Cedar Falls Utilities	Cedar Falls GT	GAS TURB	GAS	21.19
Cedar Falls Utilities	Council Bluffs	STEAM	COAL	19.75
Cedar Falls Utilities	George Neal South	STEAM	COAL	15.6
Cedar Falls Utilities	Iowa Distributed Wind Generation Project	WIND	WIND	0.5
Cedar Falls Utilities	Iowa Distributed Wind Generation Project	WIND	WIND	0.5
Cedar Falls Utilities	Iowa Distributed Wind Generation Project	WIND	WIND	0.5
Central Iowa Power Coop	Fair	STEAM	COAL	23.4
Central Iowa Power Coop	Fair	STEAM	COAL	41
Central Iowa Power Coop	Summit Lake	COMB CYC	OIL	80.2
Central Iowa Power Coop	Summit Lake	INT COMB	OIL	1
Central Iowa Power Coop	Summit Lake	INT COMB	OIL	1
Central Iowa Power Coop	Summit Lake	INT COMB	OIL	1
Central Iowa Power Coop	Summit Lake	INT COMB	OIL	1
Central Iowa Power Coop	Council Bluffs	STEAM	COAL	73.28
Central Iowa Power Coop	Louisa	STEAM	COAL	31.27
Central Iowa Power Coop	Duane Arnold	NUCLEAR	NUCLEAR	103.9
Coon Rapids Municipal Utilities	Neal (IA)	STEAM	COAL	3.24
Coon Rapids Municipal Utilities	George Neal South	STEAM	COAL	3.24
Corn Belt Power Coop	Earl F. Wisdom	STEAM	COAL	37.3
Corn Belt Power Coop	Neal (IA)	STEAM	COAL	72.57
Corn Belt Power Coop	Council Bluffs	STEAM	COAL	24.21
Corn Belt Power Coop	George Neal South	STEAM	COAL	72.57

APPENDIX D CONTINUED

Corn Belt Power Coop	Duane Arnold	NUCLEAR	NUCLEAR	51.95
Durant Municipal Electric Plant	Durant	INT COMB	OIL	0.46
Durant Municipal Electric Plant	Durant	INT COMB	OIL	0.44
Durant Municipal Electric Plant	Durant	INT COMB	OIL	1.85
Eldridge Municipal Light Dept.	Louisa	STEAM	COAL	3.4
Geneseo Municipal Utilities	Louisa	STEAM	COAL	3.4
Gowrie Municipal Utilities	Gowrie	INT COMB	OIL	0.93
Gowrie Municipal Utilities	Gowrie	INT COMB	OIL	0.97
Graettinger Municipal Utilities	Neal (IA)	STEAM	COAL	1.06
Graettinger Municipal Utilities	George Neal South	STEAM	COAL	1.06
Grand Junction Municipal Light Plant	Grand Junction	INT COMB	OIL	0.49
Grand Junction Municipal Light Plant	Grand Junction	INT COMB	OIL	1.6
Grand Junction Municipal Light Plant	Grand Junction	INT COMB	OIL	1.6
Harlan Municipal Utilities	Louisa	STEAM	COAL	5.44
Hopkinton Municipal Utilities	Hopkinton	INT COMB	OIL	1.6
Hopkinton Municipal Utilities	Hopkinton	INT COMB	OIL	1.71
Hopkinton Municipal Utilities	Hopkinton	INT COMB	OIL	1.2
IES Utilities, Inc.	Sixth Street	STEAM	COAL	3
IES Utilities, Inc.	Sixth Street	STEAM	COAL	5.24
IES Utilities, Inc.	Sixth Street	STEAM	COAL	19.22
IES Utilities, Inc.	Sixth Street	STEAM	COAL	20.19
IES Utilities, Inc.	Sixth Street	STEAM	COAL	32.49
IES Utilities, Inc.	Sutherland	STEAM	COAL	31
IES Utilities, Inc.	Sutherland	STEAM	COAL	31
IES Utilities, Inc.	Sutherland	STEAM	COAL	81
IES Utilities, Inc.	Ames (IES)	INT COMB	OIL	1
IES Utilities, Inc.	Ames (IES)	INT COMB	OIL	1
IES Utilities, Inc.	Centerville (IES)	INT COMB	OIL	2.1
IES Utilities, Inc.	Centerville (IES)	INT COMB	OIL	2.1

APPENDIX D CONTINUED

IES Utilities, Inc.	Centerville (IES)	INT COMB	OIL	2.1
IES Utilities, Inc.	Marshalltown	GAS TURB	OIL	55.5
IES Utilities, Inc.	Marshalltown	GAS TURB	OIL	53.8
IES Utilities, Inc.	Marshalltown	GAS TURB	OIL	53.2
IES Utilities, Inc.	Marshalltown	INT COMB	OIL	2
IES Utilities, Inc.	Marshalltown	INT COMB	OIL	1.9
IES Utilities, Inc.	North Centerville	GAS TURB	OIL	23.1
IES Utilities, Inc.	North Centerville	GAS TURB	OIL	25
IES Utilities, Inc.	Panora	INT COMB	OIL	1.5
IES Utilities, Inc.	Panora	INT COMB	OIL	1
IES Utilities, Inc.	Agency GT	GAS TURB	GAS	15.9
IES Utilities, Inc.	Agency GT	GAS TURB	GAS	15.6
IES Utilities, Inc.	Agency GT	GAS TURB	GAS	15.7
IES Utilities, Inc.	Agency GT	GAS TURB	GAS	16.55
IES Utilities, Inc.	Burlington (IES)	GAS TURB	GAS	15.9
IES Utilities, Inc.	Burlington (IES)	GAS TURB	GAS	16.5
IES Utilities, Inc.	Burlington (IES)	GAS TURB	GAS	16.5
IES Utilities, Inc.	Burlington (IES)	GAS TURB	GAS	14.2
IES Utilities, Inc.	Grinnell	GAS TURB	GAS	24.3
IES Utilities, Inc.	Grinnell	GAS TURB	GAS	22.9
IES Utilities, Inc.	Prairie Creek	STEAM	GAS	10
IES Utilities, Inc.	Red Cedar Cogen	GAS TURB	GAS	18
IES Utilities, Inc.	Burlington (IES)	STEAM	COAL	211.8
IES Utilities, Inc.	Neal (IA)	STEAM	COAL	144.2
IES Utilities, Inc.	Ottumwa - IES	STEAM	COAL	343.44
IES Utilities, Inc.	Prairie Creek	STEAM	COAL	21.5
IES Utilities, Inc.	Prairie Creek	STEAM	COAL	49
IES Utilities, Inc.	Prairie Creek	STEAM	COAL	142
IES Utilities, Inc.	Duane Arnold	NUCLEAR	NUCLEAR	363.65

APPENDIX D CONTINUED

IES Utilities, Inc.	Anamosa	HYDRO	HYDRO	0.25
IES Utilities, Inc.	Iowa Falls	HYDRO	HYDRO	0.54
IES Utilities, Inc.	Maquoketa - IES	HYDRO	HYDRO	0.6
IES Utilities, Inc.	Maquoketa - IES	HYDRO	HYDRO	0.6
Independence Municipal Light Plant	Independence IA	INT COMB	OIL	2.35
Independence Municipal Light Plant	Independence IA	INT COMB	OIL	0.4
Independence Municipal Light Plant	Independence IA	INT COMB	OIL	0.8
Independence Municipal Light Plant	Independence IA	INT COMB	OIL	0.8
Independence Municipal Light Plant	Independence IA	INT COMB	OIL	2.8
Independence Municipal Light Plant	Independence IA	INT COMB	OIL	5.8
Independence Municipal Light Plant	Independence IA	INT COMB	OIL	1.86
Independence Municipal Light Plant	Independence IA	INT COMB	OIL	1.86
Indianola Municipal Utilities	Indianola	GAS TURB	OIL	18.5
Indianola Municipal Utilities	Indianola	INT COMB	OIL	0.6
Indianola Municipal Utilities	Indianola	INT COMB	OIL	1.2
Indianola Municipal Utilities	Indianola	INT COMB	OIL	0.8
Indianola Municipal Utilities	Indianola	INT COMB	OIL	1.2
Indianola Municipal Utilities	Indianola	INT COMB	OIL	3.5
Indianola Municipal Utilities	Indianola	INT COMB	OIL	4.8
Interstate Power Co.	Dubuque	STEAM	COAL	30
Interstate Power Co.	Dubuque	STEAM	COAL	35
Interstate Power Co.	Dubuque	STEAM	COAL	13
Interstate Power Co.	Fox Lake	STEAM	COAL	84
Interstate Power Co.	Kapp	STEAM	COAL	217
Interstate Power Co.	Lansing	STEAM	COAL	15.5
Interstate Power Co.	Lansing	STEAM	COAL	10.7
Interstate Power Co.	Lansing	STEAM	COAL	33.8
Interstate Power Co.	Neal (IA)	STEAM	COAL	134.35
Interstate Power Co.	Dubuque	INT COMB	OIL	2.3

APPENDIX D CONTINUED

Interstate Power Co.	Dubuque	INT COMB	OIL	2.3
Interstate Power Co.	Fox Lake	GAS TURB	OIL	21.3
Interstate Power Co.	Hills	INT COMB	OIL	2
Interstate Power Co.	Hills	INT COMB	OIL	2
Interstate Power Co.	Lansing	INT COMB	OIL	1
Interstate Power Co.	Lansing	INT COMB	OIL	1
Interstate Power Co.	Mason City Gt (Lime Creek)	GAS TURB	OIL	35
Interstate Power Co.	Mason City Gt (Lime Creek)	GAS TURB	OIL	35
Interstate Power Co.	Montgomery (MN)	GAS TURB	OIL	22.2
Interstate Power Co.	New Albin	INT COMB	OIL	0.7
Interstate Power Co.	Rushford	INT COMB	OIL	2
Interstate Power Co.	Fox Lake	STEAM	GAS	12
Interstate Power Co.	Fox Lake	STEAM	GAS	12
Interstate Power Co.	Kapp	STEAM	GAS	18
Interstate Power Co.	George Neal South	STEAM	COAL	134.35

APPENDIX D CONTINUED

Maquoketa Municipal Power	Maquoketa - MMP	INT COMB	OIL	1.83
Maquoketa Municipal Power	Maquoketa - MMP	INT COMB	GAS	1
Maquoketa Municipal Power	Maquoketa - MMP	INT COMB	GAS	2
Maquoketa Municipal Power	Maquoketa - MMP	INT COMB	GAS	1.55
Maquoketa Municipal Power	Maquoketa - MMP	INT COMB	GAS	2.4
Maquoketa Municipal Power	Maquoketa - MMP	INT COMB	GAS	6.5
McGregor Municipal Utilities	McGregor	INT COMB	OIL	1.21
McGregor Municipal Utilities	McGregor	INT COMB	OIL	0.27
McGregor Municipal Utilities	McGregor	INT COMB	OIL	0.55
MidAmerican Energy Co.	Neal (IA)	STEAM	COAL	253.16
MidAmerican Energy Co.	Nimeca Diesels	INT COMB	OIL	41.04
MidAmerican Energy Co.	Pleasant Hill (MIDAM)	GAS TURB	OIL	35
MidAmerican Energy Co.	Pleasant Hill (MIDAM)	GAS TURB	OIL	35
MidAmerican Energy Co.	Pleasant Hill (MIDAM)	GAS TURB	OIL	78
MidAmerican Energy Co.	Coralville	GAS TURB	GAS	16
MidAmerican Energy Co.	Coralville	GAS TURB	GAS	16
MidAmerican Energy Co.	Coralville	GAS TURB	GAS	16
MidAmerican Energy Co.	Coralville	GAS TURB	GAS	16
MidAmerican Energy Co.	Electrifarm	GAS TURB	GAS	55.5
MidAmerican Energy Co.	Electrifarm	GAS TURB	GAS	63.1
MidAmerican Energy Co.	Electrifarm	GAS TURB	GAS	67
MidAmerican Energy Co.	Merle Parr	GAS TURB	GAS	15.4
MidAmerican Energy Co.	Merle Parr	GAS TURB	GAS	15.4
MidAmerican Energy Co.	Moline	GAS TURB	GAS	16
MidAmerican Energy Co.	Moline	GAS TURB	GAS	16
MidAmerican Energy Co.	Moline	GAS TURB	GAS	16
MidAmerican Energy Co.	Moline	GAS TURB	GAS	16
MidAmerican Energy Co.	River Hills	GAS TURB	GAS	14.5
MidAmerican Energy Co.	River Hills	GAS TURB	GAS	14.5

APPENDIX D CONTINUED

MidAmerican Energy Co.	River Hills	GAS TURB	GAS	14.5
MidAmerican Energy Co.	River Hills	GAS TURB	GAS	14.5
MidAmerican Energy Co.	River Hills	GAS TURB	GAS	14.5
MidAmerican Energy Co.	River Hills	GAS TURB	GAS	14.5
MidAmerican Energy Co.	River Hills	GAS TURB	GAS	14.5
MidAmerican Energy Co.	River Hills	GAS TURB	GAS	14.5
MidAmerican Energy Co.	Sycamore (MIDAM)	GAS TURB	GAS	74.5
MidAmerican Energy Co.	Sycamore (MIDAM)	GAS TURB	GAS	74.5
MidAmerican Energy Co.	Council Bluffs	STEAM	COAL	46
MidAmerican Energy Co.	Council Bluffs	STEAM	COAL	88
MidAmerican Energy Co.	Council Bluffs	STEAM	COAL	504.03
MidAmerican Energy Co.	George Neal South	STEAM	COAL	253.16
MidAmerican Energy Co.	Louisa	STEAM	COAL	598.14
MidAmerican Energy Co.	Neal (IA)	STEAM	COAL	135
MidAmerican Energy Co.	Neal (IA)	STEAM	COAL	300
MidAmerican Energy Co.	Neal (IA)	STEAM	COAL	370.8
MidAmerican Energy Co.	Ottumwa - IES	STEAM	COAL	372.06
MidAmerican Energy Co.	Riverside (MIDAM)	STEAM	COAL	5
MidAmerican Energy Co.	Riverside (MIDAM)	STEAM	COAL	130
MidAmerican Energy Co.	Quad Cities	NUCLEAR	NUCLEAR	192.25
MidAmerican Energy Co.	Quad Cities	NUCLEAR	NUCLEAR	192.25
MidAmerican Energy Co.	Moline	HYDRO	HYDRO	0.8
MidAmerican Energy Co.	Moline	HYDRO	HYDRO	0.8
MidAmerican Energy Co.	Moline	HYDRO	HYDRO	0.8
MidAmerican Energy Co.	Moline	HYDRO	HYDRO	0.8
Milford Municipal Utilities	Neal (IA)	STEAM	COAL	2.18
Milford Municipal Utilities	George Neal South	STEAM	COAL	2.18
Montezuma Municipal Light & Power	Montezuma (MONT)	INT COMB	OIL	1.86
Mount Pleasant Utilities	Mount Pleasant	INT COMB	OIL	1

APPENDIX D CONTINUED

Muscatine Power & Water	Muscatine	STEAM	COAL	83.72
Muscatine Power & Water	Muscatine	STEAM	GAS	25.4
Muscatine Power & Water	Muscatine	STEAM	COAL	162
New Hampton Municipal Light Plant	New Hampton	INT COMB	GAS	3.5
New Hampton Municipal Light Plant	New Hampton	INT COMB	GAS	5
New Hampton Municipal Light Plant	New Hampton	INT COMB	GAS	5
Northwest Iowa Power Coop	Neal (IA)	STEAM	COAL	56.35
Northwest Iowa Power Coop	George Neal South	STEAM	COAL	56.35
NorthWestern Public Service	Neal (IA)	STEAM	COAL	54.16
NorthWestern Public Service	George Neal South	STEAM	COAL	54.16
Osage Municipal Light & Power Dept.	Osage (OSAG)	INT COMB	OIL	3.13
Osage Municipal Light & Power Dept.	Osage (OSAG)	INT COMB	OIL	6.07
Osage Municipal Light & Power Dept.	Osage (OSAG)	INT COMB	OIL	3.64
Osage Municipal Light & Power Dept.	Osage (OSAG)	INT COMB	OIL	3.64
Pella Municipal Power & Light Dept.	Pella	STEAM	COAL	12.5
Pella Municipal Power & Light Dept.	Pella	STEAM	COAL	26.5
Rockford Municipal Light Plant	Rockford	INT COMB	OIL	1.6
Spencer Municipal Utilities	Neal (IA)	STEAM	COAL	7.55
Spencer Municipal Utilities	Spencer (SPENCE)	JET ENG	OIL	20
Spencer Municipal Utilities	George Neal South	STEAM	COAL	7.55
State Center Municipal Electric Light	State Center	INT COMB	OIL	0.6
State Center Municipal Electric Light	State Center	INT COMB	OIL	0.6
State Center Municipal Electric Light	State Center	INT COMB	OIL	1.36
State Center Municipal Electric Light	State Center	INT COMB	OIL	1.36
State Center Municipal Electric Light	State Center	INT COMB	GAS	2.5
Strawberry Point Municipal Light	Strawberry Point	INT COMB	OIL	0.85
Strawberry Point Municipal Light	Strawberry Point	INT COMB	OIL	0.37
Strawberry Point Municipal Light	Strawberry Point	INT COMB	OIL	1.03
Tipton Municipal Utilities	Louisa	STEAM	COAL	3.4

APPENDIX D CONTINUED

Waverly Light & Power	East Plant (WVY)	INT COMB	OIL	0.72
Waverly Light & Power	East Plant (WVY)	INT COMB	OIL	0.72
Waverly Light & Power	East Plant (WVY)	INT COMB	OIL	1.16
Waverly Light & Power	North Plant	INT COMB	OIL	7
Waverly Light & Power	North Plant	INT COMB	GAS	1.25
Waverly Light & Power	North Plant	INT COMB	GAS	1.35
Waverly Light & Power	North Plant	INT COMB	GAS	3.5
Waverly Light & Power	North Plant	INT COMB	GAS	3.75
Waverly Light & Power	North Plant	INT COMB	GAS	3.75
Waverly Light & Power	Louisa	STEAM	COAL	7.48
Waverly Light & Power	East Hydro	HYDRO	HYDRO	0.11
Waverly Light & Power	East Hydro	HYDRO	HYDRO	0.19
Waverly Light & Power	East Hydro	HYDRO	HYDRO	0.18
Waverly Light & Power	Skeets 1	WIND	WIND	0.08
West Bend Municipal Utility	West Bend	INT COMB	OIL	1.02
West Bend Municipal Utility	West Bend	INT COMB	OIL	0.94
West Bend Municipal Utility	West Bend	INT COMB	OIL	2.04
West Liberty Municipal Electric Dept.	West Liberty	INT COMB	OIL	0.75
West Liberty Municipal Electric Dept.	West Liberty	INT COMB	OIL	2.1
West Liberty Municipal Electric Dept.	West Liberty	INT COMB	OIL	2.7
[Various Companies]	Iowa Distributed Wind Generation Project	WIND	WIND	0.26
[Various Companies]	Iowa Distributed Wind Generation Project	WIND	WIND	0.26
[Various Companies]	Iowa Distributed Wind Generation Project	WIND	WIND	0.26
MEC/Nebraska Public Power District	Cooper Station	NUCLEAR	NUCLEAR	387
Wind at Nameplate/Other Generators at Summer Rating	Total Capacity (MW)			9445.3

Appendix E
Iowa Non-Utility Generators

Company Name	Plant Name	Nameplate Capacity MW
AG Processing, Inc.	AG Processing Inc.	8.5
Alliant Energy Applications, Inc.	Industrial Applications Inc - North Pointe	1.25
Alliant Energy Applications, Inc.	Industrial Energy Applications – Belmond	4.79
Alliant Energy Applications, Inc.	Industrial Energy Applications 1	1.83
Alliant Energy Applications, Inc.	Industrial Energy Applications 10	1.14
Alliant Energy Applications, Inc.	Industrial Energy Applications 11	1
Alliant Energy Applications, Inc.	Industrial Energy Applications 12	2.65
Alliant Energy Applications, Inc.	Industrial Energy Applications 2	2.96
Alliant Energy Applications, Inc.	Industrial Energy Applications 3	2.15
Alliant Energy Applications, Inc.	Industrial Energy Applications 4	1.14
Alliant Energy Applications, Inc.	Industrial Energy Applications 5	1.6
Alliant Energy Applications, Inc.	Industrial Energy Applications 6	3.1
Alliant Energy Applications, Inc.	Industrial Energy Applications 7	5.8
Alliant Energy Applications, Inc.	Industrial Energy Applications 8	5.5
Alliant Energy Applications, Inc.	Industrial Energy Applications 9	16
Alliant Energy Applications, Inc.	Industrial Energy Applications Inc-Cedar Rapids	1.6
Alliant Energy Applications, Inc.	Industrial Energy Applications, Inc.- Ft Madison	8
Archer Daniels Midland Co.	Cedar Rapids – ADM	155
Archer Daniels Midland Co.	Des Moines – ADM	7.9
BIO-Energy Partners	Metro Park East Landfill Gas R	4.8
Cargill, Inc.	Cargill Inc - Corn Milling Div	16
Cedar Rapids Hydro Dam	5-in-1 Dam Hydroelectric	2.1
Enron Wind Development Corp.	Storm Lake I Wind Power [Alta]	80.25
Enron Wind Development Corp.	Storm Lake I Wind Power [Alta]	112.5
FPL Energy, Inc.	Cerro Gordo Wind Project	42
Integrated Community Area WWTP	Des Moines Metro WWTP	0.59
Integrated Community Area WWTP	Des Moines Metro WWTP	0.59
Iowa Methodist Medical Center	Iowa Methodist Medical Center	3.5
Iowa State University	Central Heating Plant (IOSTUN)	33
John Deere Co.	JD Powerhouse	14.5
John Deere Co.	John Deere Dubuque Works	14
Ottumwa WaterWorks & Hydroelectric	Ottumwa Water Works & Hydro	3.25
University of Iowa	University of Iowa - Main Power	21
University of Northern Iowa	University of Northern Iowa	7.5
Yuba-Bear River	Des Moines Metro WWTP	0.59

Source: EIA-412, RUS-12, FORM 1 and other sources as compiled by Resource Data International, Inc.

APPENDIX F
NEW GENERATION (OPERATIONAL AND ANNOUNCED)

State	NERC Region	Name of Facility	MW	Type	Owner/Operator	Operating Start Date
Arkansas	SPP		153	CT	Arkansas Electric Cooperative	Sum 2001
Arkansas	SPP	Union Power Partners	2720		Panda Energy	Spr 2002
Arkansas	SPP		550	CC	Southern Energy (Southern Company) (51%)/ Kinder Morgan Power(49%)	
Arkansas	SPP	Thomas B. Fitzhugh	110	CT	Arkansas Electric Cooperative	
Arkansas	SPP	Pine Bluff Energy Center	228	Cogen	SkyGen Energy / Coral Energy	Sum 2001
Arkansas	SPP	Dam 2	108	HY	Arkansas Electric Coop	1999
Illinois	MAIN	Grand Prairie Energy	500	CC	ABB Energy Ventures	
Illinois	MAIN	Grand Tower Power Station	528	CC	Ameren CIPS	Spr 2001
Illinois	MAIN	Gibson City Power Plant	234	CT	Ameren	Sum 2000
Illinois	MAIN	Kinmundy Power Plant	234	CT	Ameren	June-05
Illinois	MAIN		176	CT	Ameren	June-00
Illinois	MAIN	Equistar Chemical Morris	50	CC-Cogen	Calpine	June-00
Illinois	MAIN		270	CT	Calumet Power (Peoples Energy/Enron)	Sum 2001
Illinois	MAIN		305	CT	Calumet Energy	
Illinois	MAIN	Medina Cogeneration Plant	36	Cogen	CILCO (AES)	Sum 2001
Illinois	MAIN	Fox River Peaking Station	345	CT	Coastal Power	
Illinois	MAIN	La Salle County Station	53	Nuclear	Commonwealth Edison Co.	Sum 2001
Illinois	MAIN	University Park Energy	300	CT	Constellation Power	Sum 2001
Illinois	MAIN		537	CC	Cordova Energy (MidAmerican Energy)	2001
Illinois	MAIN	Duke Energy Lee	640	CT	Duke Energy	Sum 2001
Illinois	MAIN	Des Plaines Green Land Develop.	664	CT	Enron	2000
Illinois	MAIN	Holland	680	CC	Holland Energy	
Illinois	MAIN	Libertyville	300	CT	Indeck	
Illinois	MAIN	Pleasant Valley	300		Indeck	
Illinois	MAIN	Holiday Hills	300	CT	Indeck	
Illinois	MAIN	Rockford	300	CT	Indeck	
Illinois	MAIN	Lincoln Energy Center	664	CT	Kendall New Century Development (Enron)	2000
Illinois	MAIN	Kendall County Generation Facility	1160	CC	LS Power	Spr 2002
Illinois	MAIN	LSP Nelson Energy	1100	CC	LS Power	
Illinois	MAIN	Joppa Power Station	318	CT	MidWest Electric Power (Electric Energy)	
Illinois	MAIN	Elwood	1900	CC/CT	Peoples Energy/Dominion Energy	
Illinois	MAIN	Elwood	600	CT	Peoples Energy/Dominion Energy	Sum 2001
Illinois	MAIN	Reliant Energy Aurora	950	CT	Reliant Energy	Sum 2000

APPENDIX F CONTINUED

Illinois	MAIN	Reliant Energy McHenry County	510	CT	Reliant Energy	September-00
Illinois	MAIN	Cardinal Energy	634	CC-Cogen	Reliant Energy	2001
Illinois	MAIN	Reliant Energy Shelby County	115	CT	Reliant Energy	2000
Illinois	MAIN	Crab Orchard	328	CT	Reliant Energy	
Illinois	MAIN		45	CT	Southwestern Electric Coop	June-00
Illinois	MAIN	North Chicago Power Project	78	CT	Unicom Power (ComEd)	
Illinois	MAIN	Argo Power	750	CC-Cogen	Alliant Energy	2003
Illinois	MAIN		13		CILCO (AES)	2000
Illinois	MAIN		13		CILCO (AES)	2000
Illinois	MAIN	Byron/Braidwood	225	Nuclear	Commonwealth Edison Co.	2002
Illinois	MAIN		300	CT	Indeck	June-00
Illinois	MAIN		110		MidWest Generation	
Illinois	MAIN		800		Standard Power & Light	
Illinois	MAIN	La Salle County Station	53	Nuclear	Commonwealth Edison Co.	1999
Illinois	MAIN	Rocky Road Power Plant	100	CT	Dynegy/NRG Energy	2000
Illinois	MAIN	Reliant Energy Shelby County	225	CT	Reliant Energy	2000
Illinois	MAIN	Various portable & temporary	213	GT	ComEd	1999
Illinois	MAIN	Rocky Road Power Plant	250	CT	Dynegy/NRG Energy	1999
Illinois	MAIN	Tilton Energy Center	176		Illinois Power	1999
Illinois	MAIN	Havana Power Station	235		Illinois Power	1999
Illinois	MAIN		600		Peoples Energy/Dominion Energy	1999
Illinois	MAIN		100	CT	Soyland Power Coop	1999
Indiana	ECAR	AES Greenfield	180	CT	Matrix Power	Sum 2000
Indiana	ECAR	CinCap VII	135	CT	Cinergy	Sum 2000
Indiana	ECAR	Vermillion Generating Station	640	CT	Cinergy / Duke Energy	Sum 2000
Indiana	ECAR	Georgetown Road	240	CT	Indianapolis Power & Light (33%) / DTE Energy (67%)	Sum 2000
Indiana	ECAR		70	Portable	Indianapolis Power & Light (IPALCO)	Sum 2000
Indiana	ECAR		200	CT	Indianapolis Power & Light (IPALCO)	Sum 2001
Indiana	ECAR	Whiting Refinery	525	Cogen	Primary Energy (NiSource)	Sum 2001
Indiana	ECAR		1150	CC	PSEG Gobal	Sum 2002
Indiana	ECAR		514	CT	West Fork Land Development (Enron)	June-00
Indiana	ECAR		500		Cogentrix Energy	Late 2002
Indiana	ECAR		200	CT	DPL (Dayton Power & Light)	June-01
Indiana	ECAR		640	CT	Duke	
Indiana	ECAR		1100	CC	LS Power	2002
Indiana	ECAR	Indiana Harbor Works	50	Cogen	Primary Energy (NiSource)	Fall 2001
Indiana	ECAR		180		PSEG Gobal	June-01

APPENDIX F CONTINUED

Indiana	ECAR	Sugar Creek	300		Southern Company	2002
Indiana	ECAR	State Line	550	CC	Southern Company	January-03
Indiana	ECAR		830	CC	Tenaska	Fall 2003
Iowa	MAPP	Duane Arnold	65	Nuclear	IES Utilities (Alliant Energy)	Spr 2001
Iowa	MAPP		15.6	IC	MidAmerican Energy	2000
Iowa	MAPP		19.5	IC	MidAmerican Energy	2000
Iowa	MAPP		19.5	IC	MidAmerican Energy	2000
Iowa	MAPP	Storm Lake	193	WT	Enron Wind	1999
Iowa	MAPP	Cerro Gordo Wind Farm	42	WT	FPL Energy	1999
Iowa	MAPP	Lake Mills	7.6	IC	Lake Mills, City of	1999
Iowa	MAPP	New Hampton	10.6	IC	New Hampton, City of	1999
Kansas	MAPP	Gordon Evans Energy Center	150	CT	Kansas Gas & Electric (Western Resources)	Sum 2000
Kansas	MAPP	Gordon Evans Energy Center	150	CT	Kansas Gas & Electric (Western Resources)	Sum 2001
Kansas	SPP	Erie	22	IC	Erie, City of	1999
Kentucky	ECAR		86		Cinergy	June-01
Kentucky	ECAR		500		Columbia Electric (Columbia Energy)	
Kentucky	ECAR		640		Duke Energy	June-01
Kentucky	ECAR	Bluegrass	324		Dynegy	Sum 2001
Kentucky	ECAR		500	CT	Dynegy Power	2001
Kentucky	ECAR		500	CT	Enron	June-00
Kentucky	ECAR	Kentucky Pioneer	400	CC	Global Energy (AEP)	Spr 2003
Kentucky	ECAR		245		Perry County Coal/East Kentucky Power Coop	
Kentucky	ECAR		500		Kentucky Mountain Power (EnviroPower)	January-03
Kentucky	ECAR	JK Smith	330	GT	East Kentucky Power	1999
Kentucky	ECAR	EW Brown	328	GT	Kentucky Utilities	1999
Louisiana	SPP	Acadia Power Project	1000	CC	Cleco Corp. / Calpine	Sum 2002
Louisiana	SPP		900	Cogen	AEP	
Louisiana	SPP	Calcasieu	165	CT	Dynegy	June-01
Louisiana	SPP		540		Enron	June-01
Louisiana	SPP	PPG Industries	500	Cogen	Entergy / PPG	Sum 2002
Louisiana	SPP		530		SkyGen Energy	2001
Louisiana	SPP		550	CC	Southern Company / Cleco	Sum 2002
Louisiana	SPP		150	CT	Southern Company / Cleco	Sum 2001
Louisiana	SPP	Calcasieu	155	CT	Dynegy	2000
Louisiana	SPP	Evangeline	480	CT	Cleco	2000
Michigan	ECAR		550	Cogen	CMS Energy(70%) / DTE Energy(30%)	July-01

APPENDIX F CONTINUED

Michigan	ECAR	B.C. Cobb 1 and 3	120		Consumers Energy	June-00
Michigan	ECAR	Gallagher Road	550		Indeck Energy	
Michigan	ECAR		510	CT	Kinder Morgan Power	June-02
Michigan	ECAR		300	CC	Southern Energy	June-01
Michigan	ECAR		530	CC	Southern Energy	June-03
Michigan	ECAR	River Rouge 1	225		Detroit Edison	Sum 2000
Michigan	ECAR		20		Constellation Power/D.B. Riley	1999
Michigan	ECAR		500		Decker Energy International	2001
Michigan	ECAR		1100		Indeck Energy	Sum 2003
Michigan	ECAR		480		Nordic Electric	September-01
Michigan	ECAR	Panda Tallmadge Power	1000		Panda Energy	Late 2004
Michigan	ECAR		1000	NG	US Generating / PG&E Generating	2002
Michigan	ECAR	Delray	139.4	GT	Detroit Edison	2000
Michigan	ECAR	Dearborn Industrial Generation	160	CT	CMS Generation (CMS Energy)	1999
Michigan	ECAR	Livingston Generating Station	136	GT	CMS Generation (CMS Energy)	1999
Michigan	ECAR	Kalamazoo River Gen. Station	63	GT	CMS Generation (CMS Energy)	1999
Michigan	ECAR	Belle River	216	GT	Detroit Edison	1999
Michigan	ECAR	Greenwood	226	GT	Detroit Edison	1999
Michigan	ECAR	Conners Creek 15-16	300		Detroit Edison	1999
Michigan	ECAR	Delray	124	CT	Detroit Edison	1999
Michigan	ECAR	Trenton Channel 7-9	34	ST	Detroit Edison	1999
Minnesota	MAPP	Pleasant Valley Station	435	CT	Great River Energy	May-01
Minnesota	MAPP	Lakefield Junction	534	CT	NRG Energy (NSP) / Tenaska	Sum 2001
Minnesota	MAPP	Black Dog	114	CC	NSP	
Minnesota	MAPP		49	CT	Minnesota Municipal Power Agency	
Minnesota	MAPP		350		Northern Alternative Energy	Late 2001
Mississippi	SERC		800		Cogentrix	Sum 2002
Mississippi	SERC	Attala Energy Facility	500	CC	Duke Energy	June-01
Mississippi	SERC	Hinds Energy Facility	500	CC	Duke Energy	June-01
Mississippi	SERC	Baxter Wilson Power Plant	300		Entergy	Sum 2001
Mississippi	SERC	Batesville Gen Facility	643.8	CC	Cogentrix / LS Power	2000
Missouri	SPP	Aries Power Plant	600	CC	Aquila Energy (Utilicorp) / Calpine	June-01
Missouri	SPP	State Line	150	CT	Empire District / Westar	May-01
Missouri	SPP	State Line	200	CC-ST	Empire District / Westar	May-01
Missouri	SPP	Hawthorn Station (#4)	140	CC	Kansas City Power & Light	Sum 2000
Missouri	SPP		45	CT	Springfield, City of	June-01
Missouri	MAIN	St. Francis II	260	CC-ST	Associated Electric Coop / Duke Energy	June-01

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Missouri	MAIN		640		Duke Energy	Sum 2001
Missouri	MAIN	Panda Montgomery Power	1000	CC	Panda Energy	Fall 2003
Missouri	SPP	Hawthorn Station #7 & #8	154	CT	Kansas City Power & Light	Sum 2000
Missouri	SPP	Hawthorn Station #5	26	ST	Kansas City Power & Light	Sum 2001
Missouri	SPP		150	CT	Springfield, City of	
Missouri	MAIN	Taum Sauk	100	Pump Stor	Ameren	1999
Missouri	SPP	Nodaway	183	GT	Associated Electric Coop	1999
Missouri	SPP	Essex	113	GT	Associated Electric Coop	1999
Missouri	SPP	St. Francis I	260	CC-ST	Associated Electric Coop / Duke Energy	1999
Missouri	SPP	Hawthorn Station #6	148	CT	Kansas City Power & Light	1999
Nebraska	MAPP	Rokeby Station	28	CT	Lincoln Electric	2001
Nebraska	MAPP	Sarpy	95		NPPD	Sum 2000
Nebraska	MAPP	Rokeby #3	90	CT	Lincoln Electric	2001
Nebraska	MAPP		100	CC	Lincoln Electric	Late 2003
Nebraska	MAPP		40	CT	Lincoln Electric	Sum 2004
Nebraska	MAPP		330	CT	Omaha Public Power District	2003
Ohio	ECAR		510	CT	AEP	2002
Ohio	ECAR	Madison Generating Station	640	CT	Cinergy / Duke Energy	Sum 2000
Ohio	ECAR		1070	CC	Cogentrix Energy	Sum 2003
Ohio	ECAR	South side	220	CT	Columbus Power Partners / MCN Energy	June-00
Ohio	ECAR	Greenville Electric Generation Station	200	CT	DPL Energy	Sum 2000
Ohio	ECAR	Darby	480	CT	DPL Energy	
Ohio	ECAR	FM Tait	320	CT	DPL Energy	
Ohio	ECAR	Lancaster Generating Station	200		DPL Energy	Sum 2001
Ohio	ECAR		500	CC	Dresden Energy (Duke?)	June-03
Ohio	ECAR		620	CC	Duke Energy	June-02
Ohio	ECAR	Richland sub site	390	CT	MidAtlantic Energy Group	Sum 2000
Ohio	ECAR	West Lorain	425	CT	Ohio Edison (First Energy)	2001
Ohio	ECAR	Napoleon Gen Facility	45	CT	PG&E Generating	June-01
Ohio	ECAR	Bowling Green Gen Facility	45	CT	PG&E Generating	Sum 2001
Ohio	ECAR		600	CT	Troy Energy (Dominion / CNG Power)	2002
Ohio	ECAR		850	CC	Waterford Energy (PSEG Global?)	May-02
Ohio	ECAR	Fremont Energy Center	700	CC	Calpine	Sum 2003
Ohio	ECAR		90		Cinergy	June-01
Ohio	ECAR	Norton Energy Storage, Phase I	300		Compressed Air Energy Storage/ Norton Energy Storage	

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Ohio	ECAR	Norton Energy Storage, Phase II	2400		Compressed Air Energy Storage/ Norton Energy Storage	2006
Ohio	ECAR		600	CT	Dominion Resources / Consolidated Natural Gas	2002
Ohio	ECAR		640	CT	Entergy	Sum 2002
Ohio	ECAR	Perry Plant site	60	UR	First Energy	June-05
Ohio	ECAR		540	CC	Global Energy (AEP)	Sum 2002
Ohio	ECAR	Galion Gen Facility	45	CT	PG&E Generating	
Ohio	ECAR	various peaking	36.6	IC	American Municipal Power-Ohio	1999
Ohio	ECAR	Bowling Green / Hamilton	64	CT	American Municipal Power-Ohio	1999
Ohio	ECAR		10	CT	American Municipal Power-Ohio	1999
Ohio	ECAR	Various	250	CT	Dayton Power & Light	1999
Oklahoma	SPP	Green Country Energy Project	800	CC	Cogentrix	January-02
Oklahoma	SPP	McClain Energy Facility - Newcastle	520	CC	Duke Energy	Sum 2001
Oklahoma	SPP		300	CT	ONEOK	June-01
Oklahoma	SPP	Oneta	1000	CC	Calpine	Spr 2002
Oklahoma	SPP	Northeastern	320	CC	Public Service Co. of Oklahoma (Central & South West)	
Oklahoma	SPP		1100		Energetix	2003
Oklahoma	SPP		900		Kiowa Power Partners (Power Resources Group)	2002
Oklahoma	SPP	Mustang 1 & 2	115		Oklahoma Gas & Electric	Sum 2000
Oklahoma	SPP	Chouteau	530	CC	Associated Electric Coop / KAMO Power	2000
Pennsylvania	ECAR		450	CT	Dominion Resources / Consolidated Natural Gas	2002
Pennsylvania	ECAR	Various	220		Allegheny Energy	Sum 2000
Pennsylvania	ECAR	Allegheny Units 1 & 2	88	CT	Allegheny Energy	1999
Texas	SPP	Tenaska Gateway Generating Station	845	CC	Tenaska	Spr 2001
Texas	SPP		430		Texas Eastman	Sum 2000
West Virginia	ECAR		500	CT	Twelvepole Creek (Columbia Electric)	Sum 2001
West Virginia	ECAR				Anker Energy	
West Virginia	ECAR				Anker Energy	
West Virginia	ECAR		450	CT	Dominion Resources / Consolidated Natural Gas	2002
West Virginia	ECAR		80	Hydro	Gauley River Power Partners/Catamount Energy	2000
West Virginia	ECAR		300		MCN	
West Virginia	ECAR		74		Virginia Power	1999
West Virginia	ECAR	Panda Culloden	1000	GT	Panda Energy	Spr 2004
West Virginia	ECAR	Belleville	42	HY	American Municipal Power-Ohio	1999
Wisconsin	MAIN	Various	223		Summer Power Source (SkyGen)	Sum 2000

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Wisconsin	MAIN	Gordon Diesel Plant	5.4	IC	Dahlberg Light & Power	
Wisconsin	MAIN	Wisconsin Wind Farm	30	WT	FPL Energy	December-00
Wisconsin	MAIN	Various			Madison Gas & Electric	
Wisconsin	MAIN	Frederic	6		Northwestern Wisconsin Electric	
Wisconsin	MAIN	Wheaton	22	CT	Northern States Power	
Wisconsin	MAIN		1050	CC	PG&E Generating	2002
Wisconsin	MAIN	Junction	6.6		River Falls Municipal Utilities	
Wisconsin	MAIN	RockGen Energy Center	525	CT	SkyGen Energy	2001
Wisconsin	MAIN	Germantown	85	CT	Wisconsin Electric (Wisconsin Energy)	June-00
Wisconsin	MAIN	Germantown	52	CT	Wisconsin Electric (Wisconsin Energy)	June-00
Wisconsin	MAIN		102	CT	Wisconsin Public Service	June-00
Wisconsin	MAIN	Various			Wisconsin Public Service	Sum 2000
Wisconsin	MAIN		500		CalEnergy	Sum 2003
Wisconsin	MAIN	[Phase I]	300	CT	Wisconsin Power & Light (Alliant Energy)	June-02
Wisconsin	MAIN	[Phase II]	200	CC	Wisconsin Power & Light (Alliant Energy)	June-03
Wisconsin	MAIN	Stoneman	250	CC	Mid-American Power/WPS Power(Wisconsin Public Service)	2002
Wisconsin	MAPP		90	CT	Minnesota Power	2002
Wisconsin	MAIN		300	CT	Southern Energy	2000
Wisconsin	MAIN		11	WT	Madison Gas & Electric	1999
Wisconsin	MAIN	Huiskamp/Middleton	20	IC	Madison Gas & Electric	1999
Wisconsin	MAIN	Custer Energy Center	17	CT	Manitowoc Public Utilities	1999
Wisconsin	MAIN		170	CT	US Generating	1999
Wisconsin	MAIN	Concord	44	GT	Wisconsin Electric Power	1999
Wisconsin	MAIN	Paris	44	GT	Wisconsin Electric Power	1999