1.0 INTRODUCTION

1.1 INTRODUCTION TO THE PROPOSED ACTION

Associated Electric Cooperative, Inc. (AECI) proposes to construct a 660 megawatt net (MW) coal-fired electricity generating unit at a site near Norborne, Missouri.

A detailed description of the Proposed Action (Project) is provided in *Section 2.3.5*, *Proposed Action*, and the location of the proposed power plant is shown on Figure 2-76 within that section. The Proposed Action includes the following components:

- Power plant and associated facilities and operations, including the plant cooling system, waste management operations, lighting, fire protection, safety, and other systems.
- 345-kilovolt (kV) substation, with associated transmission line modifications and communications facilities.
- Approximately 134 miles of new 345-kV transmission lines to connect with AECI's existing network.
- Water supply system consisting of groundwater wells and associated pipeline.
- Solid waste disposal facility.
- New rail access from existing mainline railroads.
- Actions to reduce or prevent environmental impacts.
- Materials handling including rail unloading.

The Norborne site is located in western Carroll County, Missouri, approximately 2.5 miles northwest of the town of Norborne (Figure 2-76). Water for cooling and other facility needs would be provided by wells, which would be located adjacent to the Missouri River approximately seven miles south of the site. Water requirements are estimated to average 5,600 gallons per minute (gpm), peaking to 7,400 gpm in summer. An on-site solid waste disposal facility for ash and flue gas desulfurization waste would be located just north of the power plant. An approximately 6.5-mile long rail connector to a rail line north of the plant would be constructed for coal delivery, and another line, to be used primarily for delivery of construction equipment and materials, would be constructed to connect with a rail line about one mile south of the proposed plant. The Project would include on-site water and wastewater treatment, and a water discharge line to the Missouri River.

1.2 READER'S GUIDE TO THIS DOCUMENT AND THE EIS PROCESS

The National Environmental Policy Act (NEPA) of 1969 requires that an environmental impact statement (EIS) be prepared for any federal actions that may significantly affect the environment. Because AECI, a rural electric cooperative, has applied for a loan for the Project from the U.S. Department of Agriculture, Rural Development (USDA/RD), the proposed Project constitutes a federal action for NEPA purposes.

All environmental laws and regulations applicable to the Proposed Action are summarized in *Appendix A, Relevant Federal and State Environmental Laws and Regulations*.

1.2.1 Reader's Guide

Desired information can be located in the following ways:

- Review the table of contents to find the page numbers for broad subjects of interest.

- Use the index in the back of the document to locate particular subjects and the pages on which they are found.

Acronyms and abbreviations are located in *Appendix B*; a glossary has been provided in *Section 9*.

1.2.2 EIS Process

The process for preparing an EIS is determined by the federal regulations implementing NEPA. The major steps in the EIS process are described below.

Notice of Intent (NOI) – The EIS process began when USDA/RD issued a NOI that was published in the Federal Register on August 10, 2005. The NOI announced USDA/RD's intention to prepare an EIS and hold public scoping meetings concerning the Project proposed by AECI.

Scoping Period – The purpose of scoping is to identify public and agency issues, and possible alternatives to be considered in the EIS. The scoping process included notifying the general public, and federal, state and local agencies of the Proposed Action. The scoping period, its results, and additional agency and public participation are described in *Section 6.0, Consultation and Coordination*.

Draft EIS – The Draft EIS, made available in January 2007, provided a description of the Proposed Action, considered public and agency comments received during the public scoping process, assessed the potential impacts, and identified potential measures to mitigate those impacts. A Notice of Availability (NOA) for the Final EIS was published in the Federal Register.

Comment Period and Public Hearings – The public and agencies reviewed and commented on the Draft EIS during a 45-day comment period. USDA/RD held public hearings to provide interested parties an opportunity to ask questions about and provide comments on the Draft EIS analysis; these are further described in *Section 6.0, Consultation and Coordination*. Comments received on the Draft EIS and responses to those comments are included in Appendix M.

Final EIS – The purpose of this Final EIS is for USDA/RD to assess, consider, and respond to public and agency comments received on the Draft EIS. A NOA was published in the Federal Register when the Final EIS became available. USDA/RD encourages public review of the Final EIS for 30 days after it is published.

Records of Decision (RODs) – USDA/RD will publish a ROD describing the selected action and any mitigation measures, and the factors taken into consideration in making its decisions. USDA/RD will take no action on its decision until its ROD is made available to the public.

1.3 AGENCY ROLES AND RELATIONSHIPS

1.3.1 Lead Agency--U.S. Department of Agriculture, Rural Development

Lead agencies are those preparing or taking primary responsibility for preparing the EIS. The lead agency for this EIS is USDA/RD.

1.3.2 Federal Cooperating Agency--U.S. Army Corps of Engineers

Consistent with federal regulations implementing NEPA[1] the lead agency is responsible for establishing liaison with all federal, state, local, and tribal agencies that have jurisdiction by law or special expertise with respect to any environmental impact involved in a proposed action and for requesting its participation as a cooperating agency on an EIS, as appropriate.

The U.S. Army Corps of Engineers (USACE) has agreed to participate as a cooperating agency for this EIS. This project would require obtaining certain permits from the USACE. A permit under Section 10 of the Rivers and Harbors Act would be required for the water supply wells, the discharge structure, and the transmission lines. A permit under Section 404 of the Clean Water Act (CWA) would be required for areas that discharge fill into wetlands and Waters of the United States (U.S.).

1.4 PURPOSE AND NEED

1.4.1 Purpose for the Proposed Action

AECI is a generation and transmission (G&T) cooperative that provides wholesale electric power and energy to its six members. Each of the six members is also a G&T cooperative that in turn provides wholesale electric power and energy to the third tier in a three tier system, member distribution cooperatives. AECI’s role is primarily to provide generation while the six member G&Ts primarily provide transmission of the power provided by AECI. The 51 member distribution cooperatives served by the G&Ts sell electric power and energy at retail to their member-customers in Missouri, southeastern Iowa and northeastern Oklahoma. Figure 1-1 shows AECI’s service area, the six G&Ts, and the 51 distribution cooperatives.

[1] 40 CFR 1501.5, 1501.6, 1508.5, and 1508.16

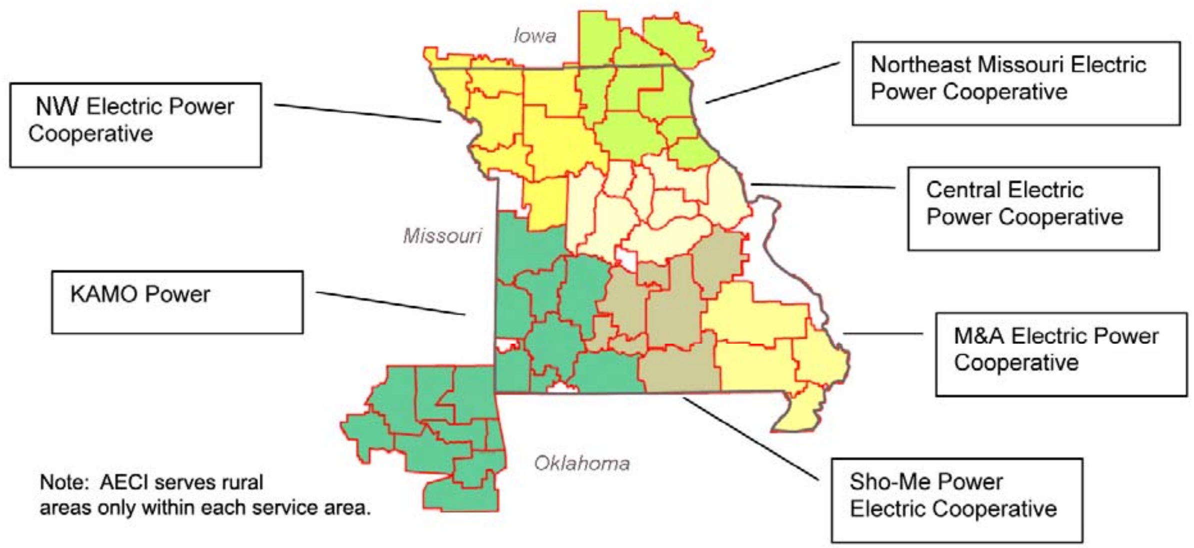

Figure 1-1. AECI Systems Service Area

Source: AECI, 2004e

AECI has "all requirements" contracts to provide the electrical power and energy needs of the G&Ts, who are similarly bound to serve the needs of the distribution cooperatives. These contracts also require the G&Ts and distribution cooperatives to buy all their power from AECI. AECI's Board of Directors is appointed by the G&Ts with the responsibility of reliably and economically serving this cooperative family.

The six G&Ts existed first; AECI was created later. In identical language, AECI's six contracts with the G&Ts state that the primary purpose of each of the G&Ts is "to furnish adequate supplies of electric power and energy to the load center of its member or affiliated cooperatives on a cooperative, non-profit basis at the lowest feasible cost" and that AECI was formed to "further the primary objective" of each of the G&Ts through the overall coordination and use of the power and transmission facilities (Holt, 1996).

As discussed in this section, AECI has identified the need to add approximately 660 MW net of baseload capacity to its system by 2012, in accordance with its contractual obligations to its members. The purpose of the Proposed Action is to provide this additional power generation to serve the needs of AECI's cooperative members.

1.4.2 Need for the Proposed Action

AECI's conclusion that a 660 MW net unit is needed by 2012 is based on a comparison of its load forecast to its capacity resources, as explained below.

1.4.2.1 Estimated Electric Loads of Cooperative Member Systems

1.4.2.1.1 Scope of Forecast

AECI's load forecast was prepared in compliance with USDA/RD guidelines as specified in the Code of Federal Regulations.[2] Among the requirements that must be addressed are:

- A discussion of the scope of the forecast.
- A discussion of the borrower personnel, consultants, data and other resources used in the preparation of the forecast.
- A discussion of the procedures used to collect, validate, process and update the data used in the study.

These requirements were addressed in detail in AECI's 2004 Electric Load Forecast Study (AECI, 2004e), which was included as part of its loan application for the Proposed Action. The results of the study, also referred to as AECI's Power Requirements Study (PRS), are summarized in this section. The forecast extended through 2025.

1.4.2.1.2 Data Sources

In addition to data provided by AECI and its distribution cooperatives, the following outside sources were used in the load forecast:

- Woods and Poole Economics, Inc. Complete Economic and Demographic Data Series (CEDDS), January 2004.
- Midwestern Climate Center database.

[2] Code of Federal Regulations, Title 7 (7 CFR), Part 1710, "General and Pre-loan Policies and Procedures Common to Insured and Guaranteed Electric Loans" as published in the Federal register. The specific requirements are contained in Section 1710.203, "Requirements to Prepare a Load Forecast".

- U.S. Department of Energy's (DOE) Energy Information Administration's Annual Energy Outlook 2004 and various issues of Monthly Energy Review.

1.4.2.1.3 Modeling

Electric load forecasts are generally based on extrapolation of historic trends for the various input factors such as population growth, income levels, weather, etc. Expected future conditions that run counter to historic trends can also be accounted for. These various projections are described by best-fit equations and regression analyses and mathematically combined to arrive at an estimated future load. (AECI, 2004e).

1.4.2.1.4 Demographic Trends

Between 1990 and 2000, population in AECI's service area increased at an average annual rate of 1.1 percent. The fastest growth occurred in the suburban areas surrounding Kansas City, St. Louis, Springfield, Branson and Tulsa. Many areas in the northern third of Missouri, southern Iowa, and the extreme southeastern corner of Missouri lost population during the 1990s. These trends follow the U.S. population shift from rural to suburban areas. Figures 1-2 and 1-3 show the distribution of population growth from the 1990 to 2000 Census in Missouri and Oklahoma. Southern Iowa is not illustrated, but tends to resemble northern Missouri. (AECI, 2004e).

Moderate population growth in AECI's service area is expected to continue throughout the forecast horizon. Total population in AECI primary service counties is projected to increase at an average annual rate of 1.0 percent from 2003 to 2023. The strongest growth is expected to occur in suburban areas surrounding the larger urban centers in the region.

Income levels are important for electric load forecasting since higher household incomes reflect the ability to purchase larger homes with more appliances, TVs, computers, entertainment systems and other electricity-consuming items, plus with proportionately greater needs for heating and air conditioning. The highest household incomes are generally found in areas surrounding larger urban centers, especially St. Louis, Kansas City, and Tulsa. Extreme northern Missouri and the southern one-third of the state have the lowest average household incomes in the state. (AECI, 2004e).

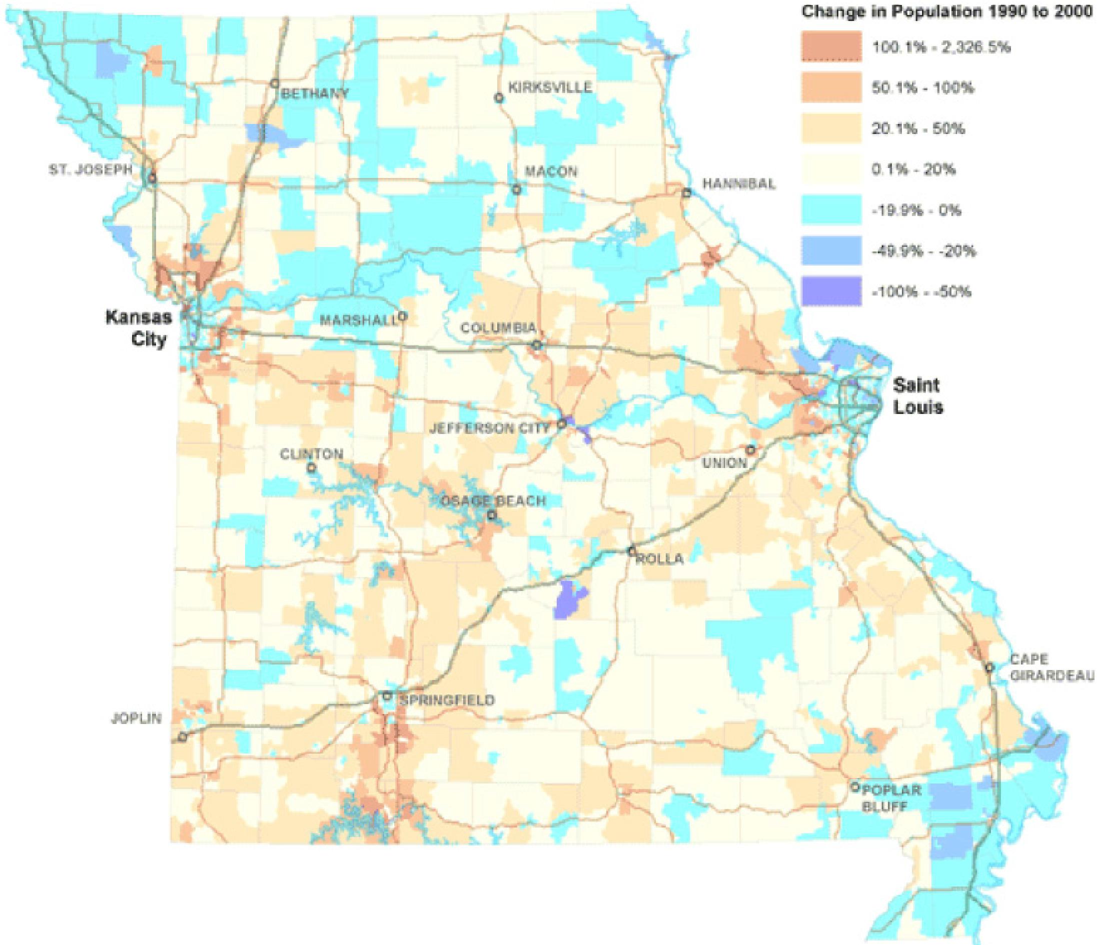

Figure 1-2. Missouri Population Changes, 1990 -2000

Source: AECI, 2004e

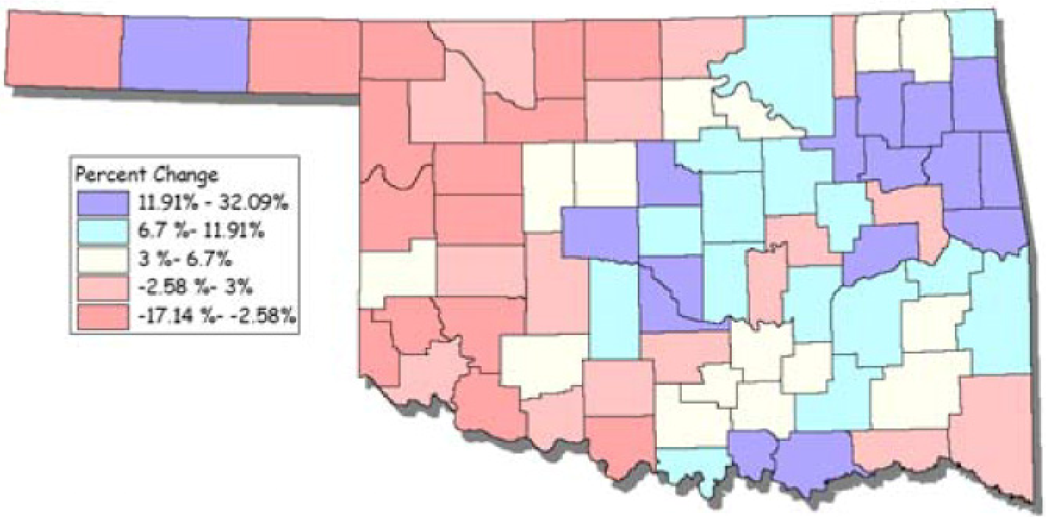

Figure 1-3. Oklahoma Population Changes, 1990 -2000

Source: AECI, 2004e

Real (inflation-adjusted) average household income in the primary AECI counties increased at an average annual rate of 1.9 percent from 1990 to 2000, then the rate of growth slowed somewhat following the 2001 recession. Real income growth in the service area is projected to increase at an average annual rate of 1.0 percent, reflecting prospects for continued income growth, but at a rate somewhat below the increases observed during the 1990s. These increases will be distributed unevenly across the service area. (AECI, 2004e).

1.4.2.1.5 Forecast Database Development

Sales, revenue and consumer data by class and monthly peak data are compiled on a regular basis by member system staff. This is typically collected on RUS [Rural Utilities Service] Form 7 filings. The historic annual data from 1984 through 2003 for each distribution cooperative, in addition to demographic data for the service area from the same time period, form the basis for the projection models. (AECI, 2004e).

Historic weather data from stations throughout the AECI service area were used to estimate air conditioning and heating needs.

The cost of electricity is a factor in forecasting load. The analysis found that the nominal (not adjusted for inflation) cost of electricity was fairly constant from 1984 through 2003. The model assumed that this trend of the declining real (inflation adjusted) cost of electricity will continue.

The price of alternate fuels for uses where electricity is an option (for example, space and water heating, cooking) also affects the forecast. The model database included projections for prices of natural gas, fuel oil, and propane.

The database also incorporated estimated saturation levels for electric space heat, electric water heating, and air conditioning. At 100 percent saturation, everyone has air conditioning, electric space heat, and electric water heating. These data are relevant because, for example, if the projected price of alternative fuels for space heating is high compared to the price of electricity, this would only make a difference for people who do not have electric heat. Or, higher income levels might mean more people would have air conditioning only if there are some people who do not now have it. (AECI, 2004e).

1.4.2.1.6 Forecasts by Consumer Category

Residential Class

This class accounted for about 89 percent of members in 2003 and 72 percent of total energy sales. The combination of projected decreases in real electricity prices and increases in electric space heat saturation as well as the projected growth in the number of consumers and in income results in projected sales growth to this class. Growth in total energy sales to the residential class was projected to average 3.1 percent per year through 2025. The average annual growth rate in electric energy sales for the five-year period preceding the study (1998 to 2003) was also 3.1 percent. (AECI, 2004e).

Small Commercial Class

AECI distribution cooperatives provided service to 63,323 small commercial consumers in 2003. This class accounted for eight percent of total members and about 16 percent of total energy sales in 2003. Given the forecasts of steadily increasing income and the expected increase in number of households, the number of small commercial consumers is projected to grow at an average annual rate of 3.0 percent through 2025. Per-consumer sales are expected to grow slowly at about 0.5 percent per year. The overall increase in electrical energy sales to this group is expected to be about 3.5 percent per year through 2025, compared with 4.4 percent from 1998 to 2003. (AECI, 2004e).

Large Commercial Class

Associated cooperatives served six-hundred and sixty six consumers that were classified as large commercial for this forecast. In most cases, this class represents uses of one million kilowatt-hours (kWhrs) or more annually. Based on the forecasts of members and average energy use, total energy sales to the large commercial class is expected to grow at 3.3 percent per year through 2025, compared with 3.9 percent from 1998 to 2003. (AECI, 2004e).

Other Classes

There are several other consumer classes, including irrigation, public lighting, public authority sales, and others, but they together make up less than 2 percent of energy sales. Energy growth forecasts for these groups ranged from about one to three percent per year through 2025 (AECI, 2004e).

1.4.2.1.7 Combined Forecasts

Total customers are projected to grow at 1.9 percent per year over the forecast horizon. Total energy sales to revenue classes by AECI cooperatives, calculated as the sum of the class energy forecasts described above, are projected to grow by 3.2 percent per year from 2003 to 2025. This compares to total system sales growth of 4.6 percent annually from 1983 to 2003. (AECI, 2004e).

AECI's own planning forecast for peak power requirements through 2016, which is somewhat lower than the model-predicted PRS forecast, is shown in Figure 1-4 along with the model-predicted forecast. The most recent forecasts, compiled from individual forecasts of each distribution cooperative, show an estimated annual growth rate of 2.6 percent in base energy consumption (GWh) over the period 2005 to 2025, and an estimated annual growth rate of 2.1 percent in base capacity needs (GW) over the same period (USDA/RD, 2007).

1.4.2.2 AECI Load Requirements and Capacity Resources

1.4.2.2.1 Variations in Requirements

Electrical energy needs vary by hour and throughout the year. In AECI's service area, peak requirements occur during the hottest days of summer.

This varying power requirement can be shown graphically with a load-duration curve. Figure 1-5 shows AECI's approximate load-duration curves for 2006 and for 2017. The x-axis on the graph shows the number of hours in a year and the y-axis shows the corresponding power needed. The loads projected for each hour are sorted from highest to lowest and placed on the graph with the highest load at the left of the x-axis. At the right side of the chart, for all 8,760 hours in a year, in 2006, at least about 1,100 MW are

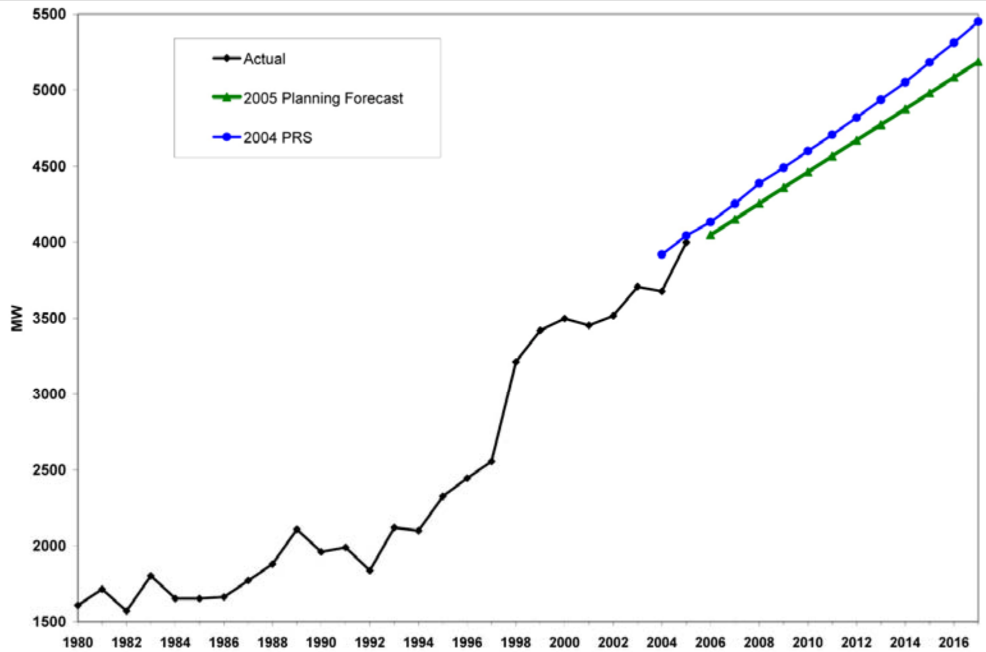

Figure 1-4. AECI Peak Demand Forecast

Source: AECI, 2004e

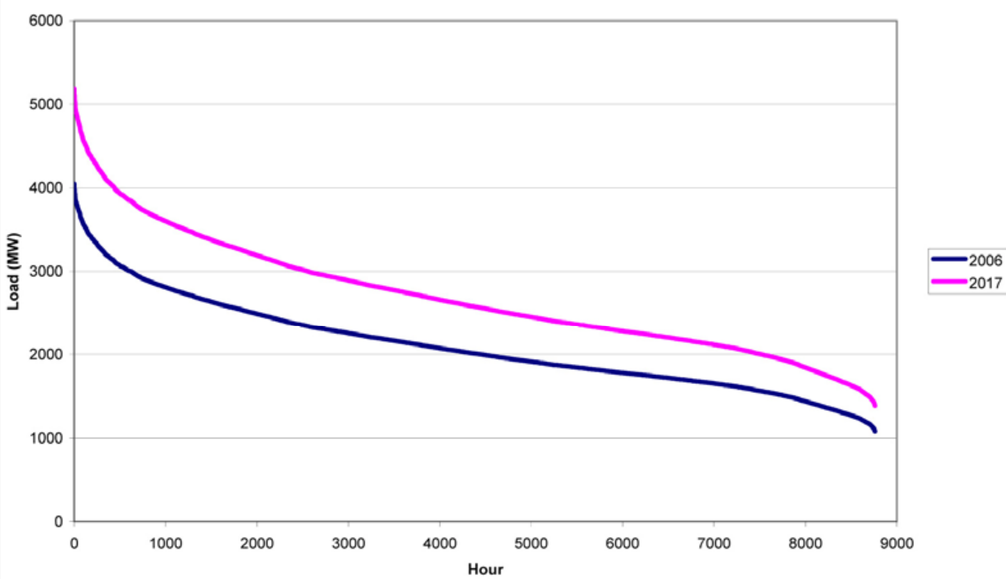

Figure 1-5. AECI Load-Duration for 2006 and 2017

Source: AECI, 2004e

always needed in AECI's system; that is, the power requirements never dip below 1,100 MW. That is the lowest power requirement. In AECI's service area, this might occur in the middle of the night on a mild spring or fall day. At the left side of the chart, very briefly during a short period of the annual maximum peak, 4,159 MW were needed in 2006. About half the time in 2006, more than 2,000 MW were needed and about half the time less than 2,000 MW were needed. For 2017, that 50th percentile load is projected to be about 2,700 MW.

To economically meet its members' energy needs, AECI needs a combination of base, intermediate, and peak load energy sources. The energy needs that are present for at least about half the time are usually most economically met by baseload plants. AECI's target is to meet about 50 to 60 percent of its load requirement with baseload units. Baseload plants are generally more expensive to build, require more time to start up, but are less expensive to operate once they have started. AECI's baseload energy resources are all coal-fired. The baseload plants are generally kept running for an extended period of time (that is, they have capacity factors greater than 80 percent). Peaking plants are usually less expensive to build, can start up and change load quickly to respond to variable demand, but have higher fuel and O&M costs. The peaking plants generally have capacity factors less than 10 percent, and intermediate load plants are in between, with some overlap. (AECI, 2006h).

1.4.2.2.2 Load Projections and Resources

Table 1-1 shows AECI's peak load projections and resource capabilities through 2017, with actual data through 2005. As shown in the table, a new 660 MW net plant (the proposed Project) is planned for 2013, when there would otherwise be a system deficit of 243 MW. The new plant would gradually be brought to full capacity, and in 2017, the surplus would be back to zero. It is most economical to time the addition so as to balance the system deficit and surplus, which includes gradually bringing the new facility to full capacity.

Table 1-1. Peak Load Projections and Resource Capabilities

	2003[1]	2004[1]	2005[1]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
System Load (MW)															
Member Coincident Peak	3,708	3,678	3,999	4,048	4,152	4,255	4,359	4,462	4,566	4,670	4,773	4,877	4,980	5,084	5,187
Reserve Requirements	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608
System Peak w/ Reserve Requirement	4,316	4,286	4,607	4,656	4,760	4,863	4,967	5,070	5,174	5,278	5,381	5,485	5,588	5,692	5,795
Resource Capacity (summer peaking MW[2])															
Thomas Hill 1 - Baseload	170	170	170	170	170	170	169	169	169	169	169	169	169	169	169
Thomas Hill 2 - Baseload	280	280	280	280	280	280	278	278	278	278	278	278	278	278	275
Thomas Hill 3 - Baseload	670	670	670	670	670	670	665	665	665	665	665	665	665	665	656
New Madrid 1 - Baseload	570	570	570	570	570	570	567	567	567	567	567	567	567	567	563
New Madrid 2 - Baseload	570	570	570	570	570	570	567	567	567	567	567	567	567	567	563
GRDA Unit 2 - Baseload	198	198	198	198	198	198	198	198	198	198	198	198	198	198	198
Chamois 1 - Baseload	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Chamois 2 - Baseload	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Chouteau - Intermediate	490	490	490	490	490	490	490	490	490	490	490	490	490	490	490
St Francis 1 - Intermediate	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
St Francis 2 - Intermediate	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
Nodaway 1 - Peaking	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Nodaway 2 - Peaking	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Essex - Peaking	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Unionville - Peaking	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Holden 1 - Peaking	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Holden 2 - Peaking	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Holden 3 - Peaking	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
SPA Peaking Contract	478	478	478	478	478	478	478	478	478	478	478	478	478	478	478
New Coal 2013 - Baseload	0	0	0	0	0	0	0	0	0	0	425	425	425	660	660
Dell - Intermediate	0	0	0	0	560	560	560	560	560	560	560	560	560	560	560
New CT 2017 - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18
New CT 2018 - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CT 2019 - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CT 2020 - Peaking	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vepco Purchase - Intermediate [3]	274	274	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Plains Purchase - Peaking	36	36	36	36	36	36	36	0	0	0	0	0	0	0	0
KCPL Capacity Sale [3]	-150	-150	0	-50	-110	-150	-150	0	0	0	0	0	0	0	0
Wind Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
City of New Madrid	-8	-7	-8	-6	-6	-6	-6	-7	-7	-7	-7	-7	-7	-8	-8
Total Capacity	4,750	4,751	4,627	4,578	5,078	5,038	5,024	5,139	5,138	5,138	5,563	5,563	5,563	5,798	5,794
Surplus (Deficit) Without Baseload Resource	434	465	20	-78	318	175	57	69	-35	-140	-243	-347	-450	-554	-660
Surplus (Deficit) as Planned	434	465	20	-78	318	175	57	69	-35	-140	182	78	-25	106	0

Notes

1) Historical data
2) This is summer peak capability in MW -- not nominal or nameplate capacity, which is less by some percentage, depending on capacity type.
3) The contracts for VEPCO purchased power and the KCPL sale both expire before the summer season in 2005 and are not included in the capacity balance for that reason in 2005. A new KCPL capacity sale contract begins in 2006, however no energy is shown for this sale because the energy is sold at market prices and is included in market sales.

Source: AECI, 2004e

The total peak loads on the system are shown at the top of the table. The "member coincident peak" is the maximum system-wide peak that occurs in a year. This is from AECI's 2005 planning projection (Figure 1-4), which, as noted previously, is a little lower than the projection based on the econometric modeling used in the PRS process. The reserve requirement is a Board-mandated safety factor to allow for the possibility of any one resource being completely unavailable. Since that resource could be AECI's largest (670 MW), that capacity amount is used for the reserve. A portion (62 MW) of that reserve requirement is provided through a firm power purchase that includes reserves. The resulting net reserve requirement is 608 MW. For each year, the reserve amount is added to the projected peak to arrive at the system peak with reserve requirements.

The table then lists all AECI's resources, with capacity. Resources that are planned are shown with zero capacity until they come on-line. Each resource is listed as baseload, intermediate or peaking. All the existing baseload resources are coal-fired. Those designated as intermediate are combined-cycle natural gas-fired facilities (AECI, 2006f). The peaking resources are simple-cycle natural gas-fired units except for Unionville, which is oil-fired, and the Southwest Power Authority (SPA) contract, which is for hydroelectricity. Hydroelectric power is available for a limited number of hours in the year based on the storage in the reservoirs, and is thus used for peak loads. The simple-cycle natural gas-fired plants can respond quickly to varying needs, but fuel costs are high compared to fuel for baseload plants.

The Dell plant, which is planned to be available in 2007, is a combined-cycle natural gas-fired plant.

1.4.2.2.3 Need for Additional Baseload Resources

In Table 1-1, for each year, the available resource capacities are totaled and compared with the requirements, both with and without the proposed Project. As shown in the table, AECI is projected to have a small capacity deficit of 78 MW in 2006. However, in 2007 the Dell combined cycle plant will come into service and AECI is expected to have a surplus until 2011. Without the Proposed Action, the deficit grows to 243 MW in 2013, and 660 MW net in 2017. Without the Proposed Action, AECI's baseload capacity is 2490 MW. While there is no firm rule about the percentage of time that baseload capacity meets system load, it is not unreasonable to expect that capacity to meet the load for 60% of the time. As can be seen from the load duration curve (Figure 1-5), AECI's baseload capacity would be several hundred megawatts below this criteria in 2017 without the Proposed Action. The capacity and baseload deficits demonstrate the need for the proposed baseload addition.