ALTERNATIVES REPORT

PROPOSED BASELOAD POWER PLANT

Prepared for the

Rural Utilities Service

Associated Electric Cooperative, Inc.

August 2005

Burns & McDonnell
SINCE 1898

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Prepared for:

Rural Utilities Service

Prepared by:

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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ACRONYM LIST

AECI	Associated Electric Cooperative, Inc.
AFB	Air Force Base
AQCR	Air Quality Control Region
AQRV	air quality related values
ASM	Archaeological Survey of Missouri
AWEA	American Wind Energy Association
BACT	Best Achievable Control Technology
BNSF	Burlington-Northern Santa Fe Railroad
CA	Conservation Area
CAA	Clean Air Act
Central	Central Electric Power Cooperative
CFR	Code of Federal Regulations
cfs	cubic feet per second
CMSU	Central Missouri State University
CO	carbon monoxide
CSR	Code of State Regulations
DSM	demand side management
DOE	Department of Energy
EIS	environmental impact statement
EPA	Environmental Protection Agency
FAA	Federal Aviation Administration
FEMA	Federal Emergency Management Agency
FGD	flue gas desulfurization
FIRM	Flood Insurance Rate Map
FLM	Federal Land Managers
gpm	gallons per minute
G&Ts	Generation &Transmission Cooperatives
IGCC	integrated gasification combined-cycle
KCPL	Kansas City Power & Light
km	kilometer
kV	kilovolt
MDC	Missouri Department of Conservation
MDNR	Missouri Department of Natural Resources
MGD	million gallons per day
MINT	Missouri-Iowa-Nebraska Transmission 345 kV line project
MKT	Missouri-Kansas-Texas Railroad
MMBTU	million British thermal units
MW	megawatt
MWh	megawatt-hour
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act

NESC	National Electric Safety Code
NOx	nitrogen oxide
NO_2	nitrogen dioxide
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NREL	National Renewable Energy Laboratory
NRHP	National Register of Historic Places
NS	Norfolk Southern Railroad
NSR	New Source Review
NW	NW Electric Cooperative
NWI	National Wetlands Inventory
NWR	National Wildlife Refuge
O_3	Ozone
Pb	lead
PM	particulate matter
PSD	Prevention of Significant Deterioration
RUS	Rural Utilities Service
SAC	Strategic Air Command
SCR	selective catalytic reduction
SO_2	sulfur dioxide
TCP	Traditional Cultural Properties
tpy	tons per year
TVA	Tennessee Valley Authority
UP	Union Pacific Railroad
U.S.C.	United States Code
USCOE	U.S. Army Corps of Engineers
USDA	U.S. Department of Agriculture
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VOR	Very High Frequency Omni-Directional Range
WA	Wildlife Area
7Q10	7-day average, 10-year low flow

1.0 EXECUTIVE SUMMARY

Associated Electric Cooperative Inc., (AECI) a generation and transmission cooperative headquartered in Springfield, Missouri, proposes to develop a new 660 megawatt (MW) baseload coal-based generation unit to be located in northwestern Missouri with an in-service date of 2011. AECI's load forecast studies indicate additional baseload capacity will be needed in this timeframe to meet its members growing energy demand.

AECI provides electric service to six regional generation and transmission (G&T) cooperatives. The G&T's serve 39 distribution cooperatives in Missouri, 3 in southeast Iowa, and 9 in northeast Oklahoma. These distribution cooperatives provide electrical service directly to more than 830,000 consumer members, including businesses, farms, and households.

The existing generation facilities AECI owns and operates include three coal-fired steam units totaling 1,153 megawatts (MW) at Thomas Hill and two coal-fired units totaling 1,200 MW at New Madrid. AECI's gas-fired generation includes two combined-cycle units totaling 522 MW at Chouteau, two combined-cycle units totaling 501 MW at St. Francis, two simple-cycle units totaling 182 MW at Nodaway and one simple-cycle unit totaling 107 MW at Essex. Additionally AECI has three simple-cycle units totaling 321 MW at Holden that are gas-fired with oil backup, and one oil-fired unit totaling 45 MW at Unionville.

In addition, AECI has established power purchase agreements with several neighboring utility power generation facilities including the City of New Madrid (New Madrid Unit 1 – 570 MW), Missouri; Central Electric Power Coop (Chamois Power Plant –68 MW); KAMO Power (Grand River Dam Authority's Unit 2 – 198 MW); Southwestern Power Administration (478 MW – hydro capacity); the City of West Plains, Missouri (36 MW – peaking capacity); and Duke Trading and Energy Marketing (St. Francis).

A review of alternative ways to meet the needs of AECI was conducted. Options evaluated included load management, renewable energy resources, distributed energy, fossil fuel generation, repowering or uprating existing units, participation in another company's generation project, purchase power, and adding new transmission capacity. It was concluded that a new coal-fired unit would be the most economical, particularly at larger unit sizes.

A site selection study was then done to determine the best location for the new unit. AECI conducted several siting activities between 1977 through 2001. This work was updated as part of a 2004 siting process. The 2004 study further defined sites in those areas identified in the previous studies as suitable for fossil fuel plants. The study resulted in eight candidate siting areas in Northwest and West Central Missouri. Much of the current siting effort centers on a re-examination and update of the findings of the previous studies. As discussed in the siting study, several sites in northwest Missouri were evaluated resulting in the Norborne and Forbes Sites being selected as the proposed and alternate sites. The siting section of this report thoroughly reviewed and confirmed the work done by AECI through 2004.

For power generated by the new power plant to reach the wholesale customers of AECI, new 345-kilovolt (kV) and 161 kV transmission facilities will be needed. In section 7.0, Transmission Macro Corridor Analysis, AECI evaluated the connections needed for the Norborne Site, and the Forbes site. In summary, 125-135 miles of new transmission would be required for either location (see Section 7.0 for further information).

The results of the analysis to date indicates that the best solution to meeting AECI's load growth is to construct a 660 MW unit at the Norborne site and build approximately 135 miles of new 345 kV transmission line. Interconnections will likely occur via two new lines from the Norborne plant to the Thomas Hill Power Plant, the Sedalia Substation, and /or the Mt. Hulda substations in Missouri. The transmission studies being conducted by AECI over the next few months will confirm the best locations for the new interconnections. This constitutes AECI's proposed action.

Construction of a coal-based generating plant at the Forbes site with about 125 miles of 345 and 161 kV transmission line is AECI's proposed alternative. We believe this to be an environmentally acceptable alternative, but not superior to the proposed action at Norborne.

Because AECI intends to finance the project through a guaranteed Federal Financing Bank loan, the project represents a major federal action that must be reviewed under the National Environmental Policy Act (NEPA). The agency with responsibility to carry out the NEPA review is the Rural Utilities Service (RUS), formerly known as the Rural Electrification Administration (REA).

RUS is required by its NEPA regulations to evaluate the environmental impacts of the project and prepare an environmental impact statement (EIS) and Record of Decision (ROD). This document is the first step in the NEPA process. It is intended to provide agencies and other interested parties enough background information on the project so that they can provide feedback to RUS and the applicants regarding issues that should be addressed in the EIS.

This document presents the purpose and need for the project and identifies the various options the utility considered to meet that need including load management, renewable energy sources, distributed generation, re-powering existing units, participation in other company's projects, purchased power, and new fossil-fueled generation alternatives (gas, oil, coal). In addition, it presents the results of a site selection study that reviews previous siting studies and evaluates two proposed sites. Finally, it includes a macro-corridor study which examines the constraints and opportunities for new transmission lines that will allow the new unit to be connected to the utility's distribution system.

2.0 INTRODUCTION

AECI proposes to develop a new baseload coal-fired generation unit. The new unit would be a 660 MW net generating unit to be in-service by 2011. The projected cost of the plant and associated transmission, rail interconnections, and water supply line is approximately $1 billion (including owner's costs and interest during construction).

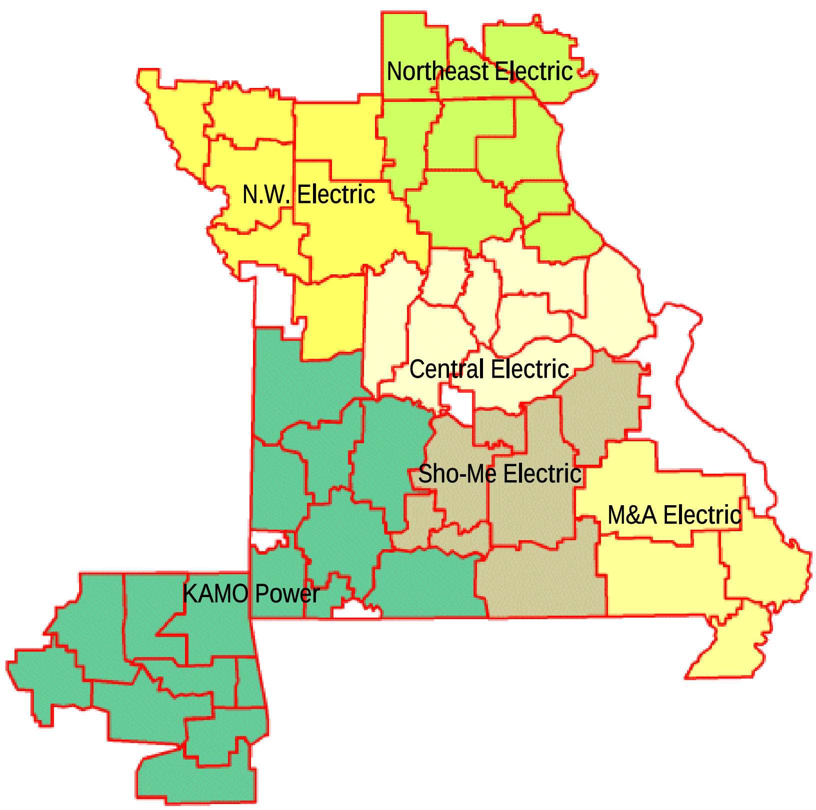
This document is actually a combination of three separate studies; an alternatives analysis, a siting study, and a macro-corridor study. The alternatives analysis is presented in Chapters 3, 4, and 5 and presents a profile of the applicant, an explanation of the purpose and need for the project, and a discussion of the capacity alternatives that were considered. These alternatives included power purchases, load management, energy conservation, and various alternative electric generation technologies. The alternatives review includes descriptions of each technology, and its general advantages and disadvantages.

The siting study is presented in Chapter 6. This chapter includes a review of previous siting studies completed by the utility, updated to include current information where appropriate. Chapter 7 is the macro-corridor study, which consists of a macro-level review of the alternative transmission corridors proposed for the project. Chapter 8 provides conclusions from the three studies (alternatives analysis, siting study and macro-corridor study), and Chapter 9 is a summary of the references used in compiling the report.

3.0 PROFILE OF AECI

Associated Electric Cooperative Inc. (AECI) is owned by, and is the major source of electric power supply for an extended system of six regional G&Ts. These G&Ts serve areas of Missouri, southern Iowa and northeast Oklahoma (See Figure 3-1). Through these electric utility systems, the G&Ts supply wholesale power to 51 distribution cooperatives. The G&T's serve 39 distribution cooperatives in Missouri, 3 in southeast Iowa, and 9 in northeast Oklahoma. These distribution cooperatives provide electrical service directly to more than 830,000 consumer members, including businesses, farms, and households. Table 3-1 lists the six regional G&Ts and their distribution cooperatives.

Figure 3-1 Generation & Transmission Cooperatives Service Area



Source: AECI, April 2005

The member G&Ts work on a regional level, and own and maintain all electrical systems from 69 kV up to 161 kV. The G&T's build and maintain the higher voltage lines, but they are planned and owned by AECI. The distribution cooperatives take on many different responsibilities including installation and maintenance of power lines (below 69 kV) from substations to consumer/members, planning for the future needs of their service area, working with communities to encourage economic development and helping their members learn to conserve energy.

AECI was founded in 1961 and given the responsibility for generation and power procurement. The transmission of the power remained the primary responsibility of the G&Ts. To help meet the objective of providing the lowest cost reliable energy, AECI is able to conduct power transactions with other utilities in and outside Missouri through its 96 interconnections, 19 interconnection agreements, and 79 interchange agreements.

The electrification of rural America enabled the rural economy to grow in many ways. In 1961, the year AECI was formed, a large majority of its electric consumers were involved in farming. Today, only 11 percent claim to receive their income from agriculture.

As the sole provider of power to its members, AECI serves a vital role in the regional rural economy. AECI is an active member of the Association of Missouri Electric Cooperatives, which assists rural electric cooperatives and promotes growth and development of Missouri's rural electric system. AECI’s success in keeping rates as low and as stable as possible, is an important attribute to communities seeking to attract and develop industry.

To provide for the system's ever-growing demand for wholesale electricity, AECI has acquired a flexible mix of resources, including thermal generation facilities, hydropower access, and power purchase agreements with neighboring utilities.

Table 3-1 List of Generation & Transmission Cooperatives

Northeast Electric Power Cooperatives	N.W. Electric Power Cooperatives	Central Electric Power Cooperatives	KAMO Power		Sho-Me Electric Power Cooperatives	M & A Electric Power Cooperatives
Access Energy Cooperative	Atchison-Holt Electric Cooperative, Inc.	Boone Electric Cooperative	Barry Electric Cooperative	Northeast Oklahoma Electric Cooperative	Crawford Electric Cooperative, Inc.	Black River Electric Cooperative
Lewis County Rural Electric Cooperative	Farmers' Electric Cooperative, Inc.	Callaway Electric Cooperative	Barton County Electric Cooperative, Inc.	Osage Valley Electric Cooperative Association	Gascosage Electric Cooperative	Ozark Border Electric Cooperative
Macon Electric Cooperative	Grundy Electric Cooperative, Inc.	Central Missouri Electric Cooperative, Inc.	Central Rural Electric Cooperative	Ozark Electric Cooperative	Howell-Oregon Electric Cooperative	Pemiscot-Dunklin Electric Cooperative
Missouri Rural Electric Cooperative	North Central Missouri Electric Cooperative, Inc.	Co-Mo Electric Cooperative, Inc.	Cookson Hills Electric Cooperative	Ozarks Electric Cooperative Corp.	Intercounty Electric Cooperative	SEMO Electric Cooperative
Ralls County Electric Cooperative	Platte-Clay Electric Cooperative, Inc.	Consolidated Electric Cooperative	East Central Oklahoma Electric Cooperative	Sac Osage Electric Cooperative	Laclede Electric Cooperative	
Tri-County Electric Cooperative Electric Cooperative	United Electric Cooperative	Cuivre River Electric Cooperative, Inc.	Indian Electric Cooperative	Southwest Electric Cooperative	Se-Ma-No Electric Cooperative	
Southern Iowa Electric Cooperative	West Central Electric Cooperative, Inc.	Howard Electric Cooperative	Kiamichi Electric Cooperative	Verdigris Valley Electric Cooperative	Southwest Electric Cooperative	
Chariton Valley Electric Cooperative		Three Rivers Electric Cooperative	Lake Region Electric Cooperative	White River Valley Electric Cooperative	Webster Electric Cooperative	
			New-Mac Electric Cooperative		White River Valley Electric Cooperative	

Source: AECI, April 2005.

4.0 PURPOSE AND NEED FOR THE PROJECT

AECI needs to add approximately 600 megawatts (MW) of reliable baseload generation to the current mix of generation resources by approximately 2011 to serve the growing loads within the service territories of the member cooperatives. The need is determined based on the projection of load growth (both peak loads and annual energy requirements), an evaluation of potential power supply options including purchase agreements and the potential to participate in other power development opportunities.

Separate from the proposed addition of baseload capacity, AECI has plans to add peaking capacity during this time period. AECI is purchasing the Dell Project from TECO Power Services (TPS), a subsidiary of TECO Energy (AECI, 2005). The partially constructed Dell Power Station is situated within the city limits of Dell, Arkansas, on approximately 100 acres. This project is a nominal 540 MW (599 MW, with duct firing) combined-cycle, natural gas-fired power plant. Construction of this facility was temporarily suspended in 2002 (TECO, 2005). AECI's plans call for completing construction and starting the Dell plant by May 2007. This plant, with strategic power purchases, will provide AECI's peaking and intermediate power needs through 2011.

4.1 DEMAND FORECAST

The most recent electrical energy demand analysis indicates that the peak capacity demand for AECI exceeded 3,650 MW during 2004. This peak capacity demand is projected to exceed 4,450 MW by 2011. The peak capacity is the amount of electrical generation capacity necessary to satisfy the peak system requirements (the point in time when the maximum energy requirement exists on the system). The capacity requirement varies during the day and by the seasons. Another tool to view the need for additional generation is the annual energy requirement which is a product of the capacity and the number of hours of operation at that capacity. The annual energy required to meet the load demands of the members in 2004, measured in megawatt hours (MWh), was 17,226,858 MWh. This annual energy usage is projected to exceed 21,244,000 MWh by 2011 and just over 30,000,000 MWh by 2025. Figure 4-1 depicts the peak capacity demand from 1980 to 2004, and projects the future demand to 2015. Figure 4-2 depicts the forecasted energy requirements from 1980 to 2025.

Figure 4-1 AECI Peak Demand, 1980 - 2014

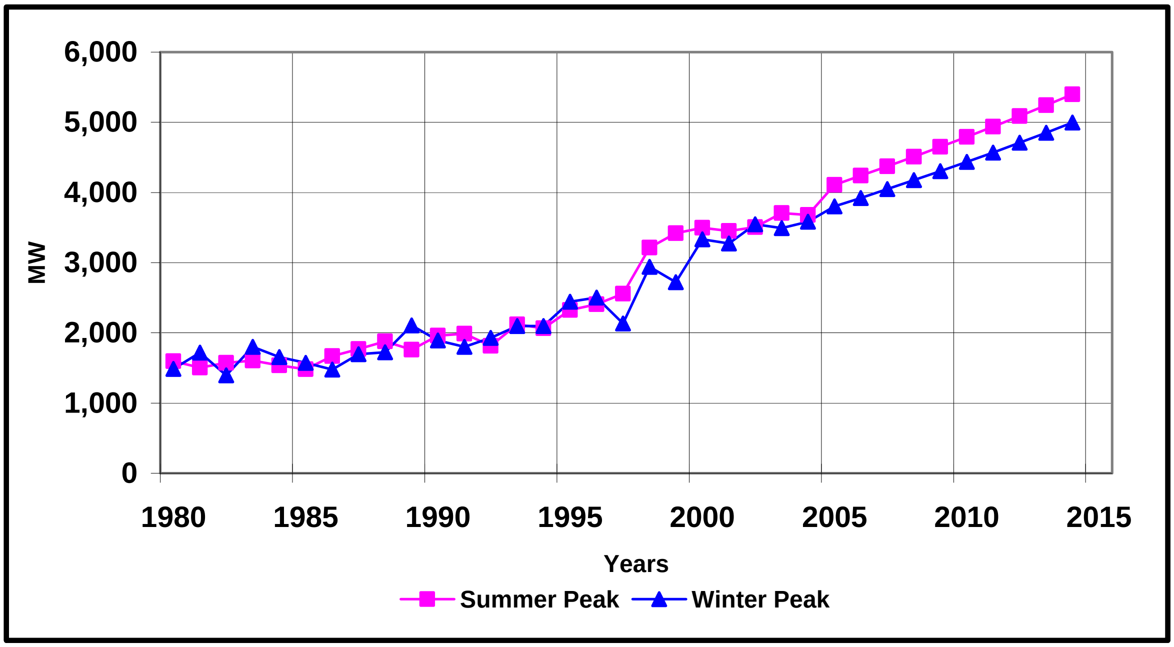


Figure 4-2 AECI Forecasted Energy Requirements, 1980 - 2025

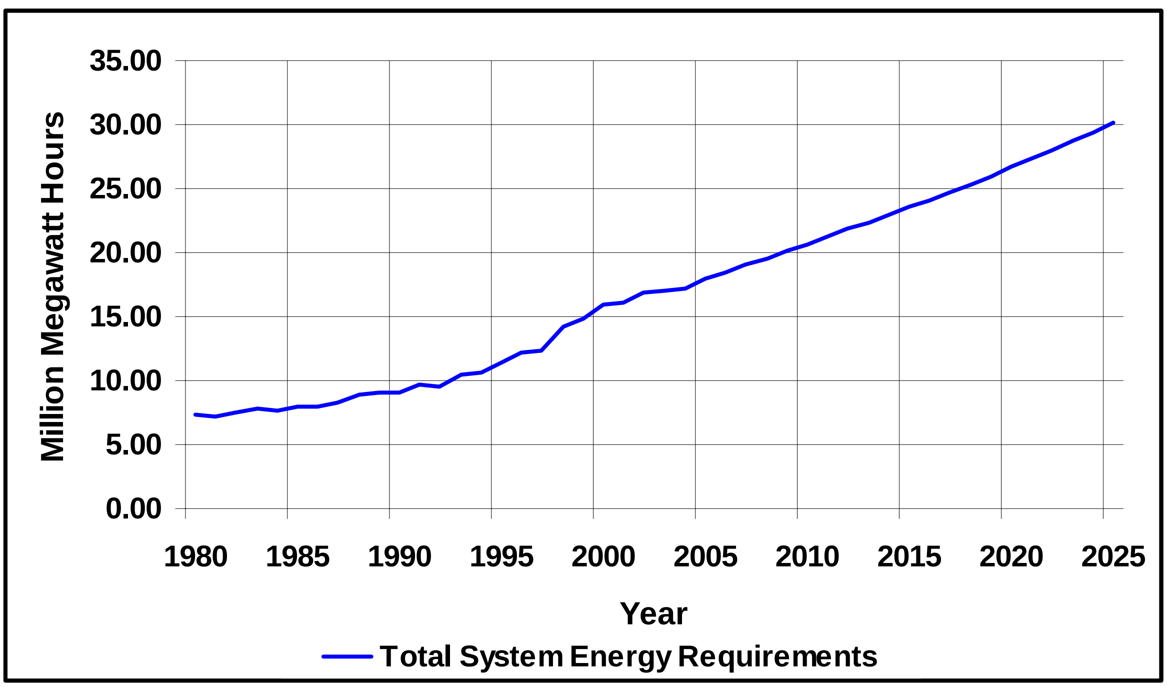


Table 4-1 presents the total peak demand for electrical energy on the AECI System. Historic information is presented for the period from 1980 to 2004 (AECI, 2005). The forecast information is shown from 2005 through 2014, and was obtained from the latest Power Requirements Study (AECI, 2001).

Table 4-1 Peak Energy Demand

Year	Summer Peak (MW) (Jul-Aug)	Winter Peak (MW) (Dec-Feb)	Year	Summer Peak (MW) (Jul-Aug)	Winter Peak (MW) (Dec-Feb)
1980	1,598	1,486	1998	3,214	2,943
1981	1,505	1,719	1999	3,421	2,720
1982	1,571	1,396	2000	3,499	3,333
1983	1,604	1,803	2001	3,453	3,273
1984	1,535	1,653	2002	3,507	3,546
1985	1,480	1,573	2003	3,708	3,494
1986	1,670	1,475	2004	3,678	3,584
1987	1,771	1,697	2005	4,108	3,802
1988	1,879	1,723	2006	4,239	3,923
1989	1,759	2,108	2007	4,374	4,048
1990	1,960	1,893	2008	4,510	4,175
1991	1,987	1,803	2009	4,649	4,303
1992	1,813	1,928	2010	4,790	4,434
1993	2,120	2,099	2011	4,937	4,569
1994	2,066	2,096	2012	5,086	4,708
1995	2,326	2,445	2013	5,241	4,851
1996	2,408	2,504	2014	5,397	4,996
1997	2,556	2,136			

Source: AECI, 2001

Table 4-2 presents the historical and forecasted system energy requirements for AECI. Historic information is presented from 1980 through 2004, and projected requirements are presented from 2005 through 2025. As noted in Table 4-3, the average growth rates over 5 year periods have varied from 3.0 to 7.2 percent over the last 15 years. The forecasted growth rates demonstrate a conservative expected average growth rate ranging from 2.9 to 2.5 percent per year for the future 5-year periods.

Table 4-2 Historic and Forecast Energy Requirements

Year	Total System Energy Requirements (MWhs)	Year	Total System Energy Requirements (MWhs)
1980	7,357,657	2003	17,083,912
1981	7,141,742	2004	17,226,858
1982	7,459,015	2005	17,935,166
1983	7,824,591	2006	18,479,105
1984	7,636,288	2007	19,039,862
1985	8,038,413	2008	19,607,604
1986	7,992,479	2009	20,168,743
1987	8,266,284	2010	20,695,684
1988	8,939,124	2011	21,244,220
1989	9,092,002	2012	21,846,128
1990	9,120,387	2013	22,394,722
1991	9,633,354	2014	22,957,199
1992	9,533,823	2015	23,533,913
1993	10,441,175	2016	24,125,226
1994	10,567,434	2017	24,731,396
1995	11,451,925	2018	25,352,797
1996	12,160,988	2019	25,989,811
1997	12,384,522	2020	26,642,831
1998	14,203,937	2021	27,312,258
1999	14,875,250	2022	27,998,505
2000	15,861,891	2023	28,701,995
2001	16,153,567	2024	29,423,161
2002	16,898,527	2025	30,162,447

Source: AECI, 2001, Includes non-Act beneficiary sales, and system losses

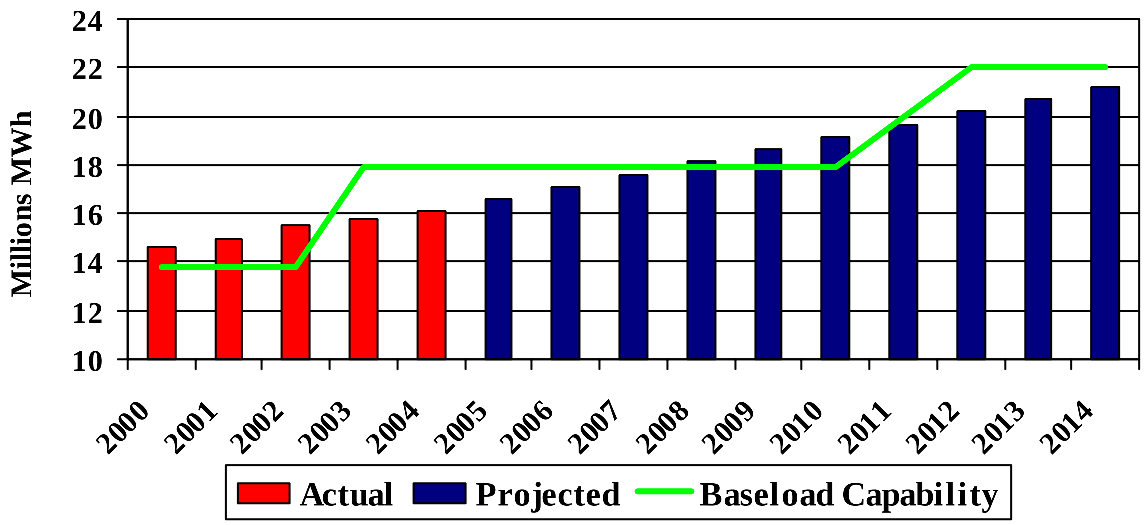
Table 4-3 Historic and Projected Energy Demand Growth Rates

Years	Average Growth Rate in Energy Requirements
1989-1994	3.1%
1994-1999	7.2%
1999-2004	3.0%
2005-2010	2.9%
2010-2015	2.6%
2015-2020	2.5%

Source: AECI, 2001

The chart below compares the actual and projected member sales to Act beneficiaries, and indicates the energy that could be generated using existing baseload capacity to meet this demand. It illustrates that the baseload capability would not meet members demand by 2 million MWh in 2012.

Figure 4-3 Comparison of Member Sales to Energy Available Through Existing Resources.



Source: AECI. Member Sales does not include non-Act beneficiary sales or system losses. Baseload Capacity represents coal fired capacity on the AECI system.

4.2 PLANNING HISTORY

The 2000 Power Requirements Study (PRS) for AECI contains the most recent 15-year forecast. This study provides a class-specific energy sales forecast, as well as system energy requirements and a forecast of peak demand. This PRS includes historical data through 1999 with projections through 2014. Prior to the completion of the 2000 PRS, AECI's previous PRS was published in 1999, and included historical data through 1997. AECI is currently in the process of developing a new PRS. This study will be available as soon as it is completed (expected in late 2005).

4.3 EXISTING RESOURCES

AECI operates a wide variety of owned and leased electrical generation resources to serve the energy requirements of its members. In addition, AECI has established power purchase agreements with several neighboring utility power generation facilities to purchase available economical resources.

4.3.1 Existing Generation Resources

Currently, AECI operates two coal-based power plants: New Madrid Power Plant (1,200 megawatts) and Thomas Hill Energy Center Power Division (1,153 MW). AECI also dispatches KAMO Power's portion of Grand River Dam Authority's Unit 2 (198 MW) and Central Electric Power Cooperative's Chamois Power Plant (68 MW), both of which are coal-based. The Chamois plant also burns a percentage of biomass fuels, such as, used railroad ties, shelled corn, sawdust, and walnut shells. The walnut shells have proven to produce the greatest amount of heat value and are routinely burned at the facility. In the summer of 2005, there is a plan to burn fescue seed hulls made available from a seed plant near Kansas City.

AECI's natural gas-based generating plants include St. Francis Power Plant (501 MW), Essex Power Plant (107 MW), Nodaway Power Plant (182 MW), Chouteau Power Plant (522 MW) and Holden Power Plant (321 MW) which also has oil backing capability.

The cooperative also owns and operates the oil-based generators at Unionville (45 MW) and has a long-term contract with the Southwestern Power Administration for 478 MW of hydroelectric peaking power. Table 4-4 provides a list of AECI's resources and their respective capacity, fuel type, and type and percentage of ownership.

4.3.2 Existing Purchase Contracts

AECI has entered into power purchase agreements with its member generation and transmission cooperatives (Member G&T's) and with the City of New Madrid, Missouri, which provide that AECI will receive the electrical output of generation facilities owned by those entities, exclusive of power reserved for certain third parties and for station service.

Table 4-4 Summary of Facilities Operated by AECI

Resource	Net Summer Capacity (MW)	Net Winter Capacity (MW)	Fuel-type	Type of Ownership	Ownership
Chouteau 11	165	165	Natural Gas	Own	100%
Chouteau 12	165	165	Natural Gas	Own	100%
Chouteau 10	165	170	Combined Cycle - Steam	Own	100%
Essex 1	107.4	112.5	Natural Gas	Own	100%
Holden 11	77.6	89.5	Natural Gas/Fuel Oil	Own	100%
Holden 12	77.6	89.5	Natural Gas/Fuel Oil	Own	100%
Holden 13	77.6	89.5	Natural Gas/Fuel Oil	Own	100%
New Madrid 1	580	580	Coal	Lease	0%
New Madrid 2	580	580	Coal	Own	100%
Nodaway 1	91.4	113.7	Natural Gas	Own	100%
Nodaway 2	91.4	113.7	Natural Gas	Own	100%
St Francis 1	225	242	Natural Gas	Own	100%
St Francis 2	248	272	Natural Gas	Own	100%
Thomas Hill 1	175	175	Coal	Own	100%
Thomas Hill 2	275	275	Coal	Own	100%
Thomas Hill 3	670	670	Coal	Own	100%
Unionville 1	22.5	22.5	Fuel Oil	Own	100%
Unionville 2	22.5	22.5	Fuel Oil	Own	100%

Source AECI, 2005

Under the terms of the agreement with the City of New Madrid, Missouri, AECI operates the City's New Madrid Unit 1. AECI also receives all capacity and energy from New Madrid Unit 1 in excess of the demand and energy reservations for the City of New Madrid, Missouri. New Madrid Unit 1 has a net generating capacity of 570 megawatts and an annual energy production of approximately 4,000,000 megawatt-hours (MWh). The agreement is in effect until bonds issued to cover the construction of the power plant by the City of New Madrid are paid, or other arrangements are made for their retirement, or 50 years has passed since the date of initial commercial operation (October 1, 1972), whichever is later.

Under the terms of the agreement with Central Electric Power Coop, AECI receives the electrical output of Central's Chamois Power Plant. The combined capacity of Chamois

Units 1 and 2 is 68 MW, and annual energy production is approximately 450,000 MWh. The agreement with Central Electric Power Coop terminates on May 31, 2040.

Under the terms of the agreement with KAMO Power, AECI receives power and energy from the 38 percent KAMO Power portion of the second unit of the Grand River Dam Authority (GRDA) power plant. The net capacity received from this unit is 197.6 MW. The energy delivered from this plant is limited to the load factor of KAMO Power's Oklahoma load. When not needed by GRDA, AECI has the ability to purchase additional energy from the power plant. The agreement with KAMO Power terminates on May 31, 2040.

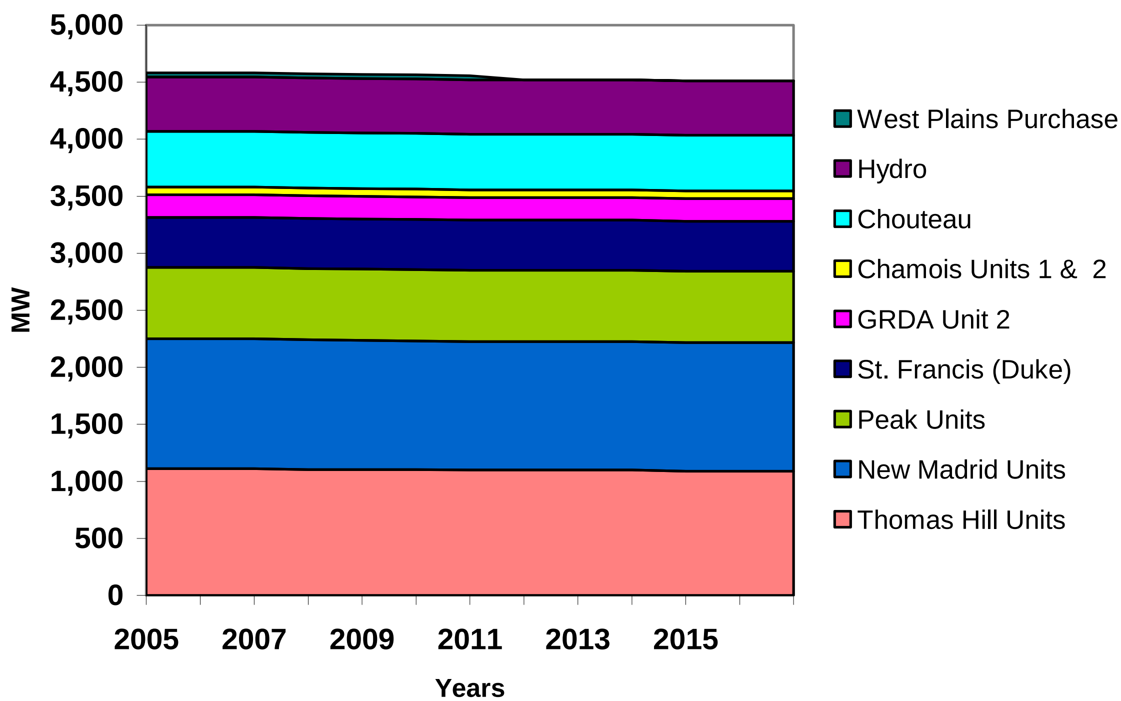
AECI has additional agreements for purchase of power and energy with Southwestern Power Administration; the City of West Plains, Missouri; and Duke Trading and Energy Marketing (Duke).

Under the terms of the agreement with Southwestern Power Administration, AECI receives a firm 478 MW hydro capacity and a commitment for this much capacity to be available for an equivalent of 1,200 hours per year (573,600 MWh of energy). In addition, AECI has the right to purchase additional supplemental energy which may be available each year. Annual supplemental energy purchases typically average 573,600 MWh. The agreement with Southwestern Power Administration terminates on February 28, 2016.

Under the terms of the agreement with the City of West Plains, Missouri AECI receives peaking capacity in excess of the load and reserve requirements of the City. The excess capacity available is approximately 36 MW. This agreement terminates on October 1, 2009.

Under the terms of the agreement with Duke, AECI has ownership in the St. Francis Power Plant Units 1 and 2. Duke has rights and obligations to half the output resulting from Units 1 and 2. AECI also has the right to purchase the capacity and energy rights from the Duke portion of both units, making a total 440-MW capacity available to AECI from the St. Francis Power Plant. The term of the agreement allows Duke the option to terminate its rights and obligations in 2009 for Unit 1, and 2011 for Unit 2; however, the figure below depicts this capacity as continuing to be available to AECI through 2016. Figure 4-4 depicts the total capacity available from the exiting resources on the AECI system.

Figure 4-4 AECI System Capacity



4.3.3 Existing Demand Side Management Resources

It is first important to note that AECI has only six G&T customers. They in turn have 51 distribution customers who supply the ultimate consumer. AECI and the six G&T's are contractually obligated to supply the power and energy demands of those consumers. Demand side management (DSM) initiatives are determined solely by the distribution cooperatives. AECI's ability to influence DSM is limited to sending appropriate price signals to the members.

In the year 2000, AECI modified its rate structure to have both a peak and base demand billing component. With the recent revisions, the demand charges are now generally determined using averages of the member's maximum monthly system demands (referred to as self-coincident peak demand) over multiple historical monthly or seasonal periods. This kind of demand billing structure encourages distribution cooperatives, through their G&T

supplier, to implement cost-effective actions to lower their peak demand especially during the period coincident with AECI's summer and winter peak.

The most common types of DSM activity among AECI members are direct load control programs. Most direct load control programs are conducted at the distribution cooperative level. Some of AECI's members are active in installing electric water heaters and ground-source heat pumps. Additionally, most of AECI's members make literature available to their consumers regarding conservation and energy efficiency. Details of the particular DSM activities of each distribution cooperative member of AECI are documented in the respective 2000 PRS report for each cooperative.

4.3.4 Incremental Upgrades

Incremental upgrades include projects to increase the output from existing facilities. There were no incremental capacity upgrades considered that would meet the need of additional baseload capacity. Under the Environmental Protection Agency's (EPA's) current regulatory interpretations, incremental upgrades can be subject to New Source Review. This reduces the potential advantages associated with improving existing facilities.

4.3.5 Power Pool Member Resources

Because lack of reliability has a huge potential cost, AECI belongs to a regional organization of utilities dedicated to preserving reliability -- the Southeastern Reliability Council (SERC), headquartered in Birmingham, AL. SERC is one of the ten (10) regional reliability councils constituting the North American Electric Reliability Council (NERC). SERC is responsible for promoting, coordinating and ensuring the reliability and adequacy of the bulk power supply systems in the area served by the Member Systems. SERC membership is comprised of investor-owned, municipal, cooperative, state and federal systems, independent power producers, and power marketers.

Because of the geographic size of the region and the diversity among its parts, the region is divided into sub-regions for data reporting purposes. These are the Virginia - Carolinas Reliability sub-region (VACAR), the Tennessee Valley Authority (TVA) sub-region (Tennessee and adjacent portions of Alabama, Georgia, Kentucky and Mississippi) the

Southern sub-region (Georgia, Alabama, part of Mississippi, and panhandle of Florida), and, effective January 1, 1998, the Operating Companies of Entergy, Associated Electric Cooperative and CAJUN Electric Power Cooperative became official members of SERC, adding a fourth sub-region to SERC.

4.3.6 Transmission System Constraints

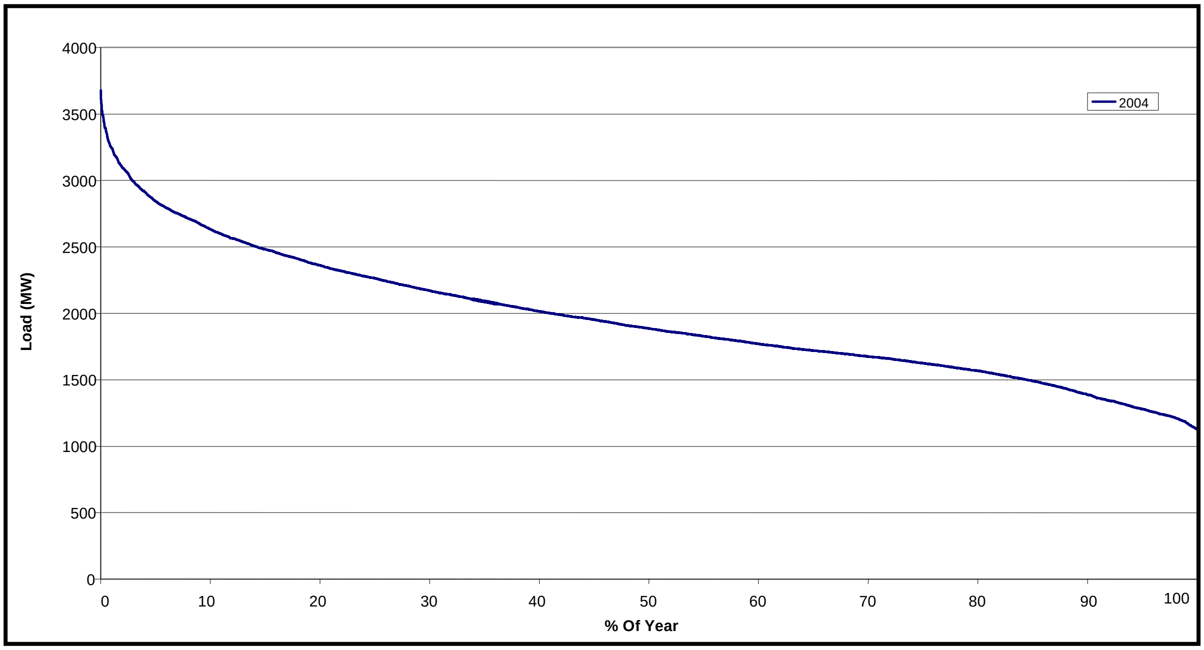
AECI and its member G&Ts currently has over 9,000 miles of high voltage transmission lines with 96 interconnection points and 79 interchange agreements with Missouri and regional power suppliers. Although there are some transmission constraints, AECI is a very strong system that provides adequate interconnection to neighboring systems. The lack of available low cost energy reserves serves as a larger constraint to the purchase of power.

4.3.7 Characteristics of Energy Needs

AECI's needs are for firm, baseload generation to meet their demand and energy requirements. As shown by the curve below in Figure 4-5, the energy requirements on AECI's system in 2004 were always greater than approximately 1,150 MW. This, plus the required reserve capacity, represents baseload capacity requirements. As discussed above, the energy demand is projected to increase in the future. The relationship between the baseload and peak load (i.e. the shape of the load duration curve) is expected to remain fairly constant. The total load exceeded 1,150 MW for essentially all of the year and for more than 50 percent of the time the demand requirements were greater than 1,850 MW. This represents intermediate load. The power requirements above this amount (i.e. needed less than 50 percent of the year represent peak loads. The total loads exceed 2,700 MW approximately 10 percent of the year. This load duration curve reflects the diversified loads on the system, and the efforts to manage peak loads.

The total number of consumers on AECI's system is projected to increase from 731,418 in 2000 to 982,741 by 2014. This equates to an expected average annual increase of 2.1 percent. Excluding the impact of the Oklahoma cooperatives' consumers, the average historical growth of the total consumers was 2.4 percent annually from 1985 to 1999.

Figure 4-5 AECI Energy Requirements, Load Duration Curve



Source: AECI, 2005

4.3.7.1 Residential

The residential class is, by far, the largest consumer class on AECI's system, accounting for approximately 92 percent of the total number of consumers in 1999. The aggregate forecast of the number of residential consumers served by AECI's members is expected to increase from 669,997 in 2000 to 897,454 by 2014. This equates to an average annual increase of 2.1 percent, slightly lower than the historical average annual rate of growth of 2.2 percent experienced from 1985 to 1999. This excludes the impact of the addition of the Oklahoma members of KAMO Power to the AECI system in 1998.

Sales to the residential class made up approximately 69 percent of AECI's total sales in 1999. Energy sales to the residential sector grew at an average annual rate of 3.7 percent during the period 1994 to 1999, excluding the impact of the addition of the Oklahoma members of KAMO Power to the AECI system. This compares to the national average residential sales growth of 2.5 percent per year over the same period. The total energy sales to the residential class is projected to grow at an average annual rate of 3.2 percent from 2000 to 2014, increasing from 8,945,388 MWh in 2000 to 13,918,587 MWh in 2014. This projected rate of growth is slightly less than the historical rate of growth in total residential energy sales from

1985 to 1999 of 3.7 percent, excluding the impact of sales to the Oklahoma cooperatives' consumers.

4.3.7.2 Small Commercial

The small commercial class (defined as commercial accounts with less than 1,000 kVA transformer capacity), accounts for slightly more than 7 percent of the total number of consumers. Typical consumers in this class include office buildings, service stations, restaurants, and other retail establishments. The number of small commercial consumers is expected to increase from 52,175 in 2000 to 73,317 by the end of the forecast period. This commercial class of consumers is forecast to increase at an average annual rate of 2.5 percent. The average annual growth rate from 1985 to 1999 was 4.5 percent without considering the impact of the addition of the Oklahoma cooperatives' consumers.

Small commercial energy sales by AECI's members, which accounted for 15 percent of the total sales in 1999, have historically grown at a faster rate than residential sales. The average annual growth rate was 5.0 percent from 1985 to 1999, excluding the impact of the Oklahoma cooperatives sales (compared to 3.7 percent for the residential class). Total small commercial sales are projected to increase from the 2000 level of 1,917,460 MWh to 2,964,478 MWh by 2014. This represents an average annual growth rate of 3.2 percent.

4.3.7.3 Large Commercial

The large commercial class includes commercial accounts with greater than 1,000 kVA transformer capacity. In 1999, the large commercial class accounted for about 9 percent of the total sales to consumers by AECI's member cooperatives. The sum of the G&Ts' forecasts indicates large commercial sales are projected to increase from 1,154,368 MWh to 1,766,992 MWh, or 3.1 percent, from 2000 through 2014. This average annual growth is considerably lower than the 9.8 percent average annual growth experienced from 1985 to 1999 and the 12.6 percent average annual growth that occurred from 1994 through 1999, excluding the addition of the Oklahoma portion of the KAMO Power system.

4.3.7.4 Other

Other classifications of consumers served by the distribution cooperatives of AECI's member G&Ts include irrigation, public street and highway lighting, other sales to public authorities, and sales for resale. The combined total energy sales to these other classes represented less than 7 percent of the total retail sales on AECI's system. The largest portion of these other sales (approximately 78 percent in 1999) represent direct sales by Sho-Me Power Electric Cooperative (Sho-Me Power) to municipal consumers. Total energy sales to these other classes of consumers is projected to grow at an average annual growth rate of 2.6 percent from 2000 to 2014, increasing from 833,261 MWh in 2000 to 1,188,268 MWh in 2014. This compares to historical average annual growth of 1.8 percent from 1985 through 1999, excluding the impact of the addition of the Oklahoma cooperatives.

Table 4-5 shows the total capacity requirements of AECI's member cooperatives, which represents the sum of the consumer class forecasts described above. Total capacity requirements are projected to increase at an average annual growth rate of 3.2 percent. This compares to average annual growth of 4.1 percent for the period 1985 to 1999 and 4.4 percent from 1994 through 1999, excluding the impact of the addition of the consumers of the Oklahoma cooperatives to the AECI system.

Table 4-5 Total Capacity Requirements

Contract Year	Coop Load (MW)	Other Loads (MW)	Required Reserve (MW)	Total Capacity Requirements (MW)
2004	3,797	2	608	4,407
2005	3,896	3	608	4,507
2006	3,996	2	608	4,606
2007	4,095	3	608	4,706
2008	4,195	3	608	4,806
2009	4,295	3	608	4,906
2010	4,394	3	608	5,005
2011	4,494	3	608	5,105
2012	4,594	3	608	5,205
2013	4,693	4	608	5,305
2014	4,793	3	608	5,404
2015	4,893	3	608	5,504
2016	4,992	4	608	5,604

Source: AECI, 2005

4.4 NEED SUMMARY

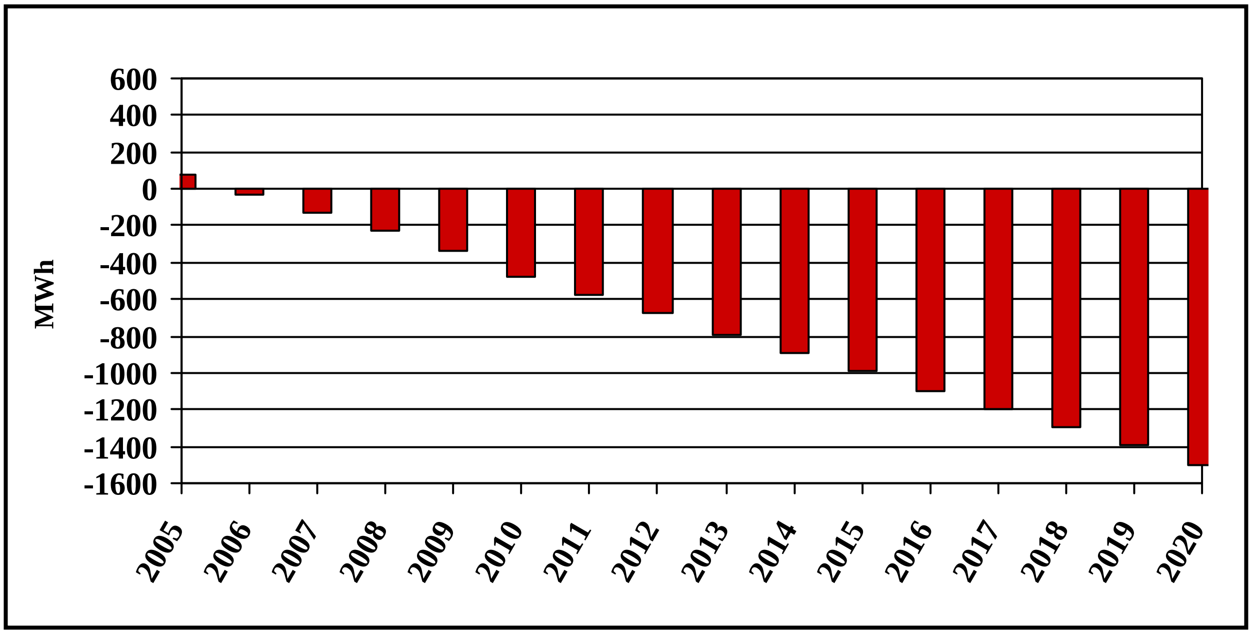
The results of the PRS, indicates a need to add approximately 660 to 700 MW of baseload generation in the 2010 – 2013 timeframe. A baseload addition in this time frame will help to provide protection against rising and volatile fuel prices. Table 4-6 indicates the system surpluses (i.e. when system resources exceed the capacity requirements), and the periods of deficits (i.e. when system resources do not satisfy the projected capacity requirements). Figure 4-6 illustrates this information in graphic form. Figure 4-7 illustrates how the addition of the Dell project reduces or eliminates the deficit for several years and Figure 4-8 illustrates how the addition of the planned coal fired generation will eliminate the deficit until approximately 2017.

Table 4-6 System Capacity and the Forecast Deficit Capacity

Year	Megawatts
2004	299
2005	75
2006	-25
2007	-133
2008	-238
2009	-341
2010	-449
2011	-584
2012	-684
2013	-784
2014	-893
2015	-992
2016	-1,091

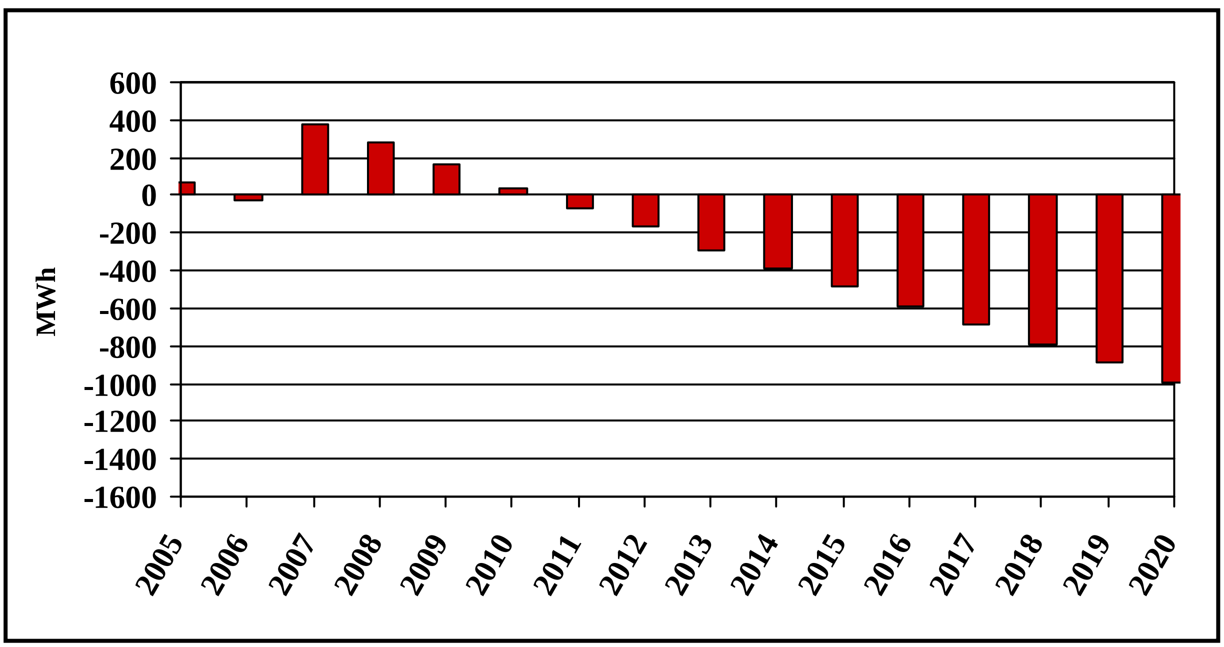
Source: AECI, 2005

Figure 4-6 AECI Projected Surplus and Deficit Capacity Without Additional Generation



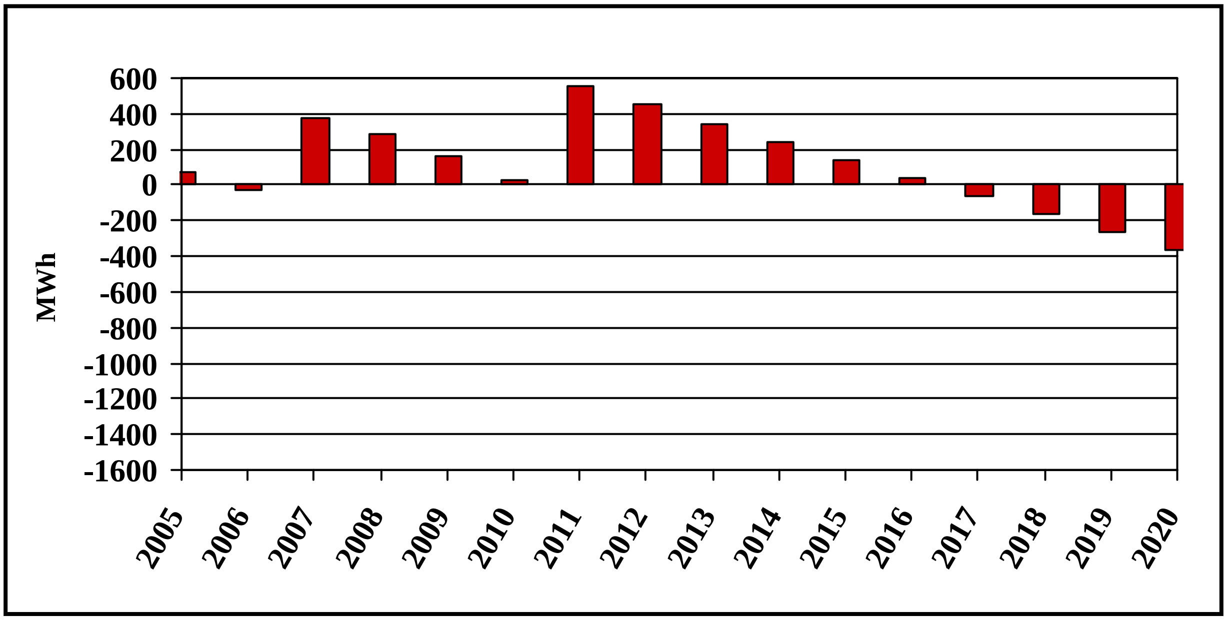
Source: AECI, 2005

Figure 4-7 AECI Projected Surplus and Deficit Capacity With Dell Addition



Source: AECI, 2005

Figure 4-8 AECI Projected Surplus and Deficit Capacity With Coal Plant Addition



Source: AECI, 2005