ALTERNATIVES REPORT

PROPOSED COMBINED-CYCLE POWER PLANT

Prepared for

Rural Development

United States Department of Agriculture

Associated Electric Cooperative, Inc.

August 2008

Burns & McDonnell
SINCE 1898

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Prepared by:

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

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ACRONYM LIST

AECI	Associated Electric Cooperative, Inc.
CEGT	CenterPoint Energy
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
EA	environmental assessment
ELFS	Electric Load Forecast Study
EPA	U.S. Environmental Protection Agency
GRDA	Grand River Dam Authority
G&Ts	Generation &Transmission Cooperatives
HRSG	heat recovery steam generator
KMIGT	Kinder Morgan Interstate Gas Transmission
kV	kilovolt
kVA	kilovolt amps
MAIP	Mid-America Industrial Park
MW	megawatt
MWh	megawatt-hour
NEPA	National Environmental Policy Act
NGPL	Natural Gas Pipeline Company
NO_x	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
OGT	Oneok Gas Transmission
PEPL	Panhandle Eastern Pipe Line Company
RD	Rural Development
SERC	Southeastern Reliability Council

1.0 EXECUTIVE SUMMARY

Associated Electric Cooperative Inc. (AECI) is a generation and transmission cooperative headquartered in Springfield, Missouri. AECI proposes to develop a new, 540-megawatt (MW) gas-fired combustion combined-cycle generation unit at an existing generation site in northeastern Oklahoma with an in-service date of early 2011. AECI's Electric Load Forecast Study (ELFS) indicated that additional intermediate capacity will be needed in this timeframe to meet its members' growing energy demand. Based on the ELFS, a 50 MW capacity deficit is projected for 2009 and this deficit is expected to grow between 80 to 100 MW per year thereafter. AECI's projected deficit will exceed approximately 130 MW and 580 MW by 2011 and 2016, respectively.

AECI provides electric service to six regional generation and transmission (G&T) cooperatives. These G&Ts 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 850,000 consumer members, including businesses, farms, and households.

The existing generation facilities AECI owns and/or operates include three coal-fired steam units totaling 1,153 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 combined-cycle units totaling 560 MW at Dell, 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 two oil-fired units totaling 45 MW at Unionville.

AECI also has established power purchase agreements with the City of New Madrid (New Madrid Unit 1 – 600 MW) in Missouri, Central Electric Power Cooperative (Chamois Power Plant – 68 MW) in Missouri, KAMO Power (Grand River Dam Authority's Unit 2 – 198 MW) in Oklahoma, Southwestern Power Administration (478 MW – hydro capacity), and the City of West Plains (36 MW – peaking capacity) in Missouri.

A review of the alternative ways AECI could meet their needs was conducted. Options evaluated included load management, the use of renewable energy resources, distributed energy, fossil fuel generation, the repowering or uprating of existing units, participation in another company's generation project, the purchase of power, or the addition of new transmission capacity. A new combustion turbine unit was determined to be the most economical alternative for AECI.

A 2007 site selection study was conducted to determine the best location for the new unit. Twenty-three potential sites in Arkansas, Missouri and Oklahoma were identified. As discussed in the 2007 siting study, the evaluation resulted in an existing power plant, the Chouteau site, being selected as the preferred site. Section 6.0 of this report provides further information on the site selection study.

The alternative that is the best solution to meet AECI's projected load growth is to construct 540 MW of generation at the existing Chouteau Power Plant. Interconnections will be accomplished via a new substation located one-half mile east of the Chouteau site and 161-kilovolt (kV) and 345-kV transmission lines extending from the facility. This alternative is AECI's proposed action.

AECI intends to finance the project through a guaranteed Federal Financing Bank loan. As a result, the project represents a major federal action that must be reviewed under the 1969 National Environmental Policy Act (NEPA). The responsible agency will be the U.S. Department of Agriculture, Rural Development (RD).

RD is required by its NEPA regulations to evaluate the environmental impacts of the project and prepare an environmental assessment (EA) and Finding of No Significant Impact. This Alternatives Report is the first step in the NEPA process. It is intended to provide agencies and other interested parties with enough background project information so that they can provide feedback to RD and the applicants regarding issues that should be addressed in the EA.

In summary, this Alternatives Report documents the purpose and need for the project and identifies the various options AECI has considered to meet the projected load growth. These options considered included 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). Alternative project sites were also considered; AECI has identified a preferred site for the new generation unit.

2.0 INTRODUCTION

AECI proposes to develop a new, gas-fired, combined-cycle generation unit. The new unit would be a 540 MW net generating unit to be in-service by early 2011. The projected cost of the project is approximately $434 million (including owner's costs and interest during construction).

The alternatives analysis presented in Chapters 3, 4, and 5 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 capacity alternatives included power purchases, load management, energy conservation, and various alternative electric generation technologies. The review of electric generation alternatives includes descriptions of each technology, along with its general advantages and disadvantages.

A review of a siting study completed by AECI is presented in Chapter 6.

3.0 PROFILE OF AECI

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, southeast Iowa and northeast Oklahoma (Figure 3-1). Through these electric utility systems, the G&Ts supply wholesale power to 51 distribution cooperatives of which 39 distribution cooperatives are in Missouri, 3 are in southeast Iowa, and 9 are in northeast Oklahoma. These distribution cooperatives provide electrical service directly to more than 850,000 consumer-members, including businesses, farms, and households. The six regional G&Ts and their distribution cooperatives are listed in Table 3-1.

Figure 3-1 Generation & Transmission Cooperatives' Service Area

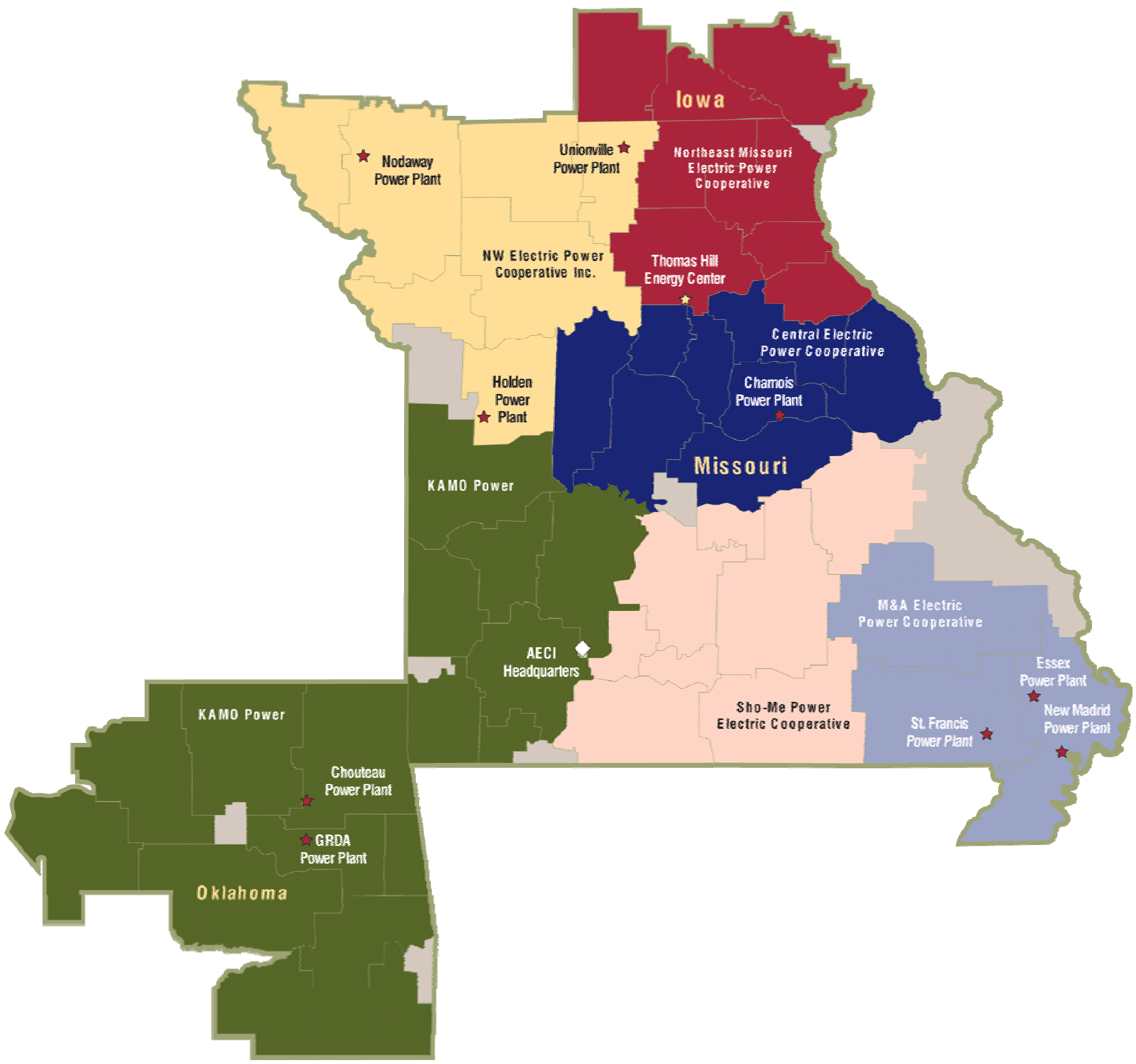

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Table 3-1 List of Regional Generation and Transmission Cooperatives

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 Corporation	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 Association	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.

The member G&Ts work on a regional level, and own and maintain all 69-kV to 161-kV electrical systems. The G&Ts 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 of Missouri through its 158 interconnections, 21 interconnection agreements and interchange agreements with 71 separate entities. Included in these 71 separate entities are investor-owned and municipal utilities, electric cooperatives, power marketing firms, and regional transmission organizations.

As the sole provider of power to its members, AECI serves an important role in the regional rural economy. AECI's stated goal is to keep rates as low and as stable as possible; AECI believes that this is an important attribute to communities seeking to attract and develop industry. To provide for the system's growing demand for wholesale electricity, AECI has established a flexible mix of generation, including thermal facilities, hydropower, and power purchase agreements with neighboring utilities.

4.0 PURPOSE AND NEED FOR THE PROJECT

AECI needs to add new intermediate generation capacity to their current mix of generation resources to serve the growing loads within the service territories of their member cooperatives. The earliest such capacity could be operational on the AECI system is estimated to be 2011. Beginning in 2009, AECI will be in a capacity deficit position. A capacity surplus or deficit is calculated as the difference between existing generating capacity and the total of the demand requirements, other load requirements, and required system reserves. This deficit is projected to be slightly over 50 megawatts (MW) in 2009 and is projected to grow between 80 and 100 MW per year thereafter. AECI's projected deficit will exceed approximately 130 MW and 540 MW by 2011 and 2016, respectively. The determination of need for new intermediate generation capacity was established based on forecasted load growth (both peak loads and annual energy requirements), an evaluation of potential power supply options including power purchase agreements, and the potential to participate in other power development opportunities.

4.1 DEMAND FORECAST

In 2007, the peak capacity demand on the AECI system exceeded 4,200 MW. This peak capacity demand is projected to exceed 4,670 MW in 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 used to assess the need for additional generation is the annual energy requirement, which is the sum of the capacity requirements for each hour of the year. The annual energy requirement in 2007, measured in megawatt-hours (MWh), was approximately 19,380,700 MWh. Annual energy requirements are projected to exceed 21,200,000 MWh by 2011 and reach a level of near 27,000,000 MWh by 2024. The historical peak capacity demand from 1980 to 2007, and the future demand through 2024 is shown in Figure 4-1. The historical and forecasted energy requirements from 1980 to 2024 are presented in Figure 4-2. Both the peak capacity demand and energy requirement forecasts are generally based upon data from AECI's 2006 Electric Load Forecast Study. The historical and projected peak capacity demand and energy requirements are also presented in Tables 4-1 and 4-2, respectively. As noted in Table 4-3, the historical average growth rate in total energy requirements over 5-year periods has varied from 2.8 to 5.4 percent over the last 15 years. The total energy requirements forecast calls for growth at rather conservative rates between 1.6 and 2.3 percent annually for the 5-year periods over the next 15 years. The growth rate for the years 1995-2000 includes the addition of the Oklahoma members of KAMO Power to the AECI system in 1998.

Figure 4-1 AECI Peak Demand, 1980 - 2024

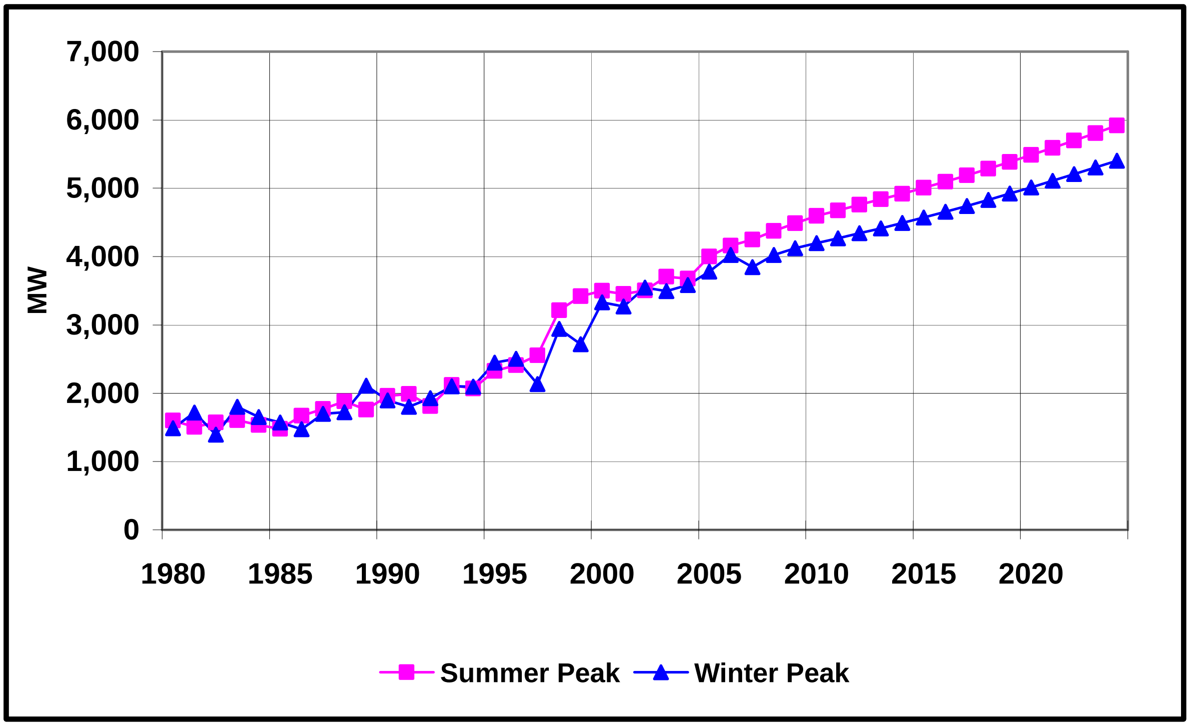


Figure 4-2 AECI Forecasted Energy Requirements, 1980 - 2024

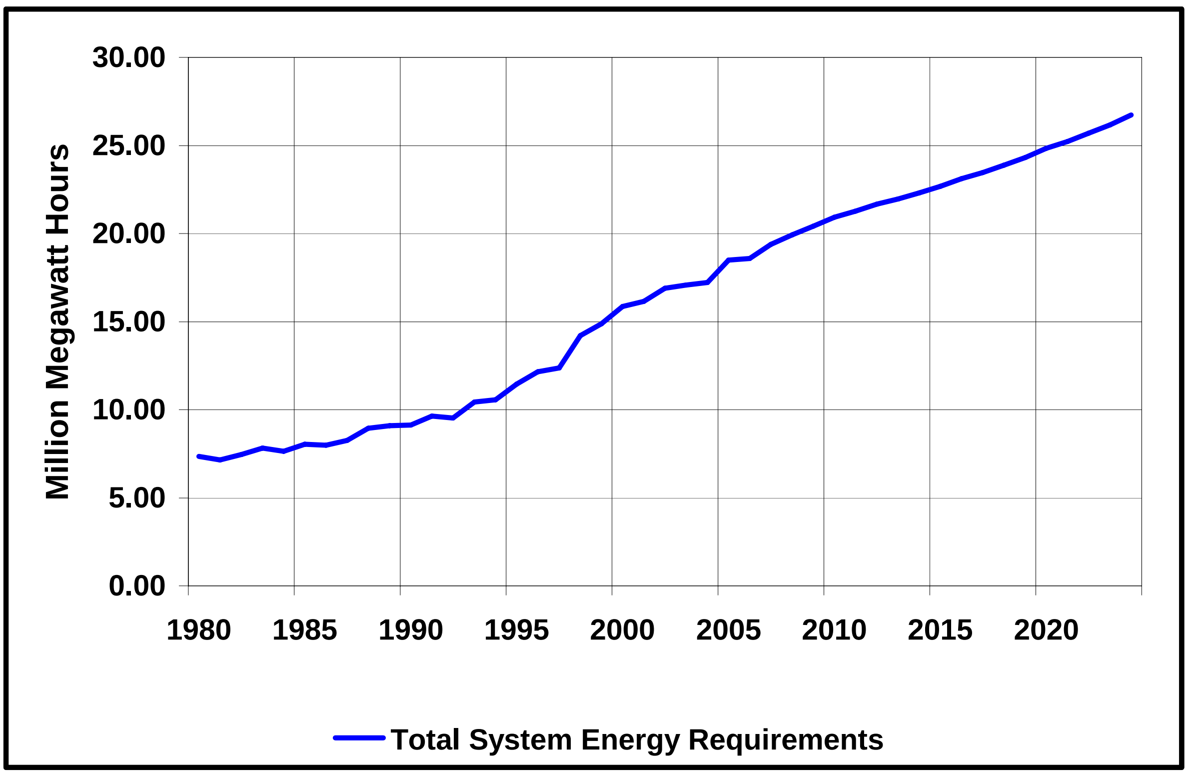


Table 4-1 Historic and Projected Peak Energy Demand

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	2003	3,708	3,494
1981	1,505	1,719	2004	3,678	3,584
1982	1,571	1,396	2005	3,999	3,783
1983	1,604	1,803	2006	4,159	4,026
1984	1,535	1,653	2007	4,248	3,844
1985	1,480	1,573	2008	4,373	4,025
1986	1,670	1,475	2009	4,485	4,123
1987	1,771	1,697	2010	4,595	4,195
1988	1,879	1,723	2011	4,676	4,268
1989	1,759	2,108	2012	4,757	4,341
1990	1,960	1,893	2013	4,839	4,412
1991	1,987	1,803	2014	4,920	4,492
1992	1,813	1,928	2015	5,009	4,570
1993	2,120	2,099	2016	5,096	4,656
1994	2,066	2,096	2017	5,191	4,739
1995	2,326	2,445	2018	5,286	4,830
1996	2,408	2,504	2019	5,385	4,921
1997	2,556	2,136	2020	5,488	5,013
1998	3,214	2,943	2021	5,592	5,109
1999	3,421	2,720	2022	5,698	5,208
2000	3,499	3,333	2023	5,809	5,304
2001	3,453	3,273	2024	5,918	5,404
2002	3,507	3,546			

Source: AECI, 2008

4.2 PLANNING HISTORY

The most recent AECI load forecast is based upon the 2006 Electric Load Forecast Study (ELFS) prepared by Clearspring Energy Associates (2006). The 2006 ELFS includes historical data through 2005 with projections through 2024. AECI is currently in the process of developing a new ELFS. This ELFS is expected to be available in late 2008.

The 2006 ELFS provides a class-specific energy sales forecast, system energy requirements, and a forecast of peak demand. AECI has used the peak demand forecast from the 2006 ELFS without adjustment for planning purposes, however, AECI has revised the energy requirements projections of the 2006 ELFS to represent a system load factor that is more consistent with historical data for their system.

Table 4-2 Historic and Projected 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	17,227,733
1982	7,459,015	2005	18,500,017
1983	7,824,591	2006	18,586,580
1984	7,636,288	2007	19,380,789
1985	8,038,413	2008	19,929,664
1986	7,992,479	2009	20,424,510
1987	8,266,284	2010	20,922,641
1988	8,939,124	2011	21,271,187
1989	9,092,002	2012	21,670,595
1990	9,120,387	2013	21,962,818
1991	9,633,354	2014	22,306,614
1992	9,533,823	2015	22,686,104
1993	10,441,175	2016	23,121,078
1994	10,567,434	2017	23,472,996
1995	11,451,925	2018	23,885,947
1996	12,160,988	2019	24,318,429
1997	12,384,522	2020	24,840,376
1998	14,203,937	2021	25,227,811
1999	14,875,250	2022	25,695,321
2000	15,861,891	2023	26,177,592
2001	16,153,567	2024	26,734,172
2002	16,898,527		

Source: AECI, 2008, 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
1993-1997	5.4%
1998-2002	6.5%
2003-2007	2.8%
2008-2012	2.3%
2013-2017	1.6%
2018-2022	1.8%

Source: AECI, 2008

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 electric resources.

4.3.1 Existing Generation Resources

Currently, AECI operates two coal-based power plants – the New Madrid Power Plant (1,200 megawatts) and the Thomas Hill Energy Center Power Division (1,153 MW). AECI also distributes KAMO Power's portion of the Grand River Dam Authority's Unit 2 (198 MW) and the Central Electric Power Cooperative's Chamois Power Plant (68 MW); both of these facilities are coal-based. The Chamois plant also burns a percentage of biomass fuels, such as used railroad ties, shelled corn, sawdust, and walnut shells.

AECI's natural gas-based generating plants include the St. Francis Power Plant (501 MW), the Essex Power Plant (107 MW), the Nodaway Power Plant (182 MW), the Chouteau Power Plant (522 MW), the Dell Power Plant (560 MW), and the Holden Power Plant (321 MW). The Holden Power Plant also has fuel oil backup capability.

AECI also owns and operates the fuel 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. AECI's resources and their respective capacity, fuel type, and type and percentage of ownership are listed in Table 4-4.

4.3.2 Existing Purchase Contracts

AECI has entered into power purchase agreements with its member generation and transmission cooperatives (Member G&Ts) and with the City of New Madrid, Missouri. Through these agreements, AECI receives the electrical output of generation facilities owned by those entities, exclusive of power reserved for certain third parties and for station service.

Under the terms of the power purchase agreement with the City of New Madrid, 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. The New Madrid Unit 1 has a net generating capacity of 570 megawatts and an annual energy production of approximately 4,000,000 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, other arrangements are made for their retirement, or 50 years has passed since the October 1, 1972 date of initial commercial operation, whichever is later.

Under the terms of the power purchase agreement with Central Electric Power Cooperative, 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 500,000 MWh. The agreement with Central Electric Power Coop terminates on May 31, 2040.

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%
Dell 1	165	174	Natural Gas	Own	100%
Dell 2	165	174	Natural Gas	Own	100%
Dell 3	229	247	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%
Totals	4,375	4,542.4			

Source AECI, 2008

Under the terms of the power purchase agreement with KAMO Power, AECI receives 38 percent of the power and energy from KAMO Power from 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 to AECI from this plant is limited to the load factor of KAMO Power's Oklahoma load. When not needed by the GRDA, AECI has the ability to purchase additional energy from the power plant. The agreement with KAMO Power terminates on May 31, 2040.

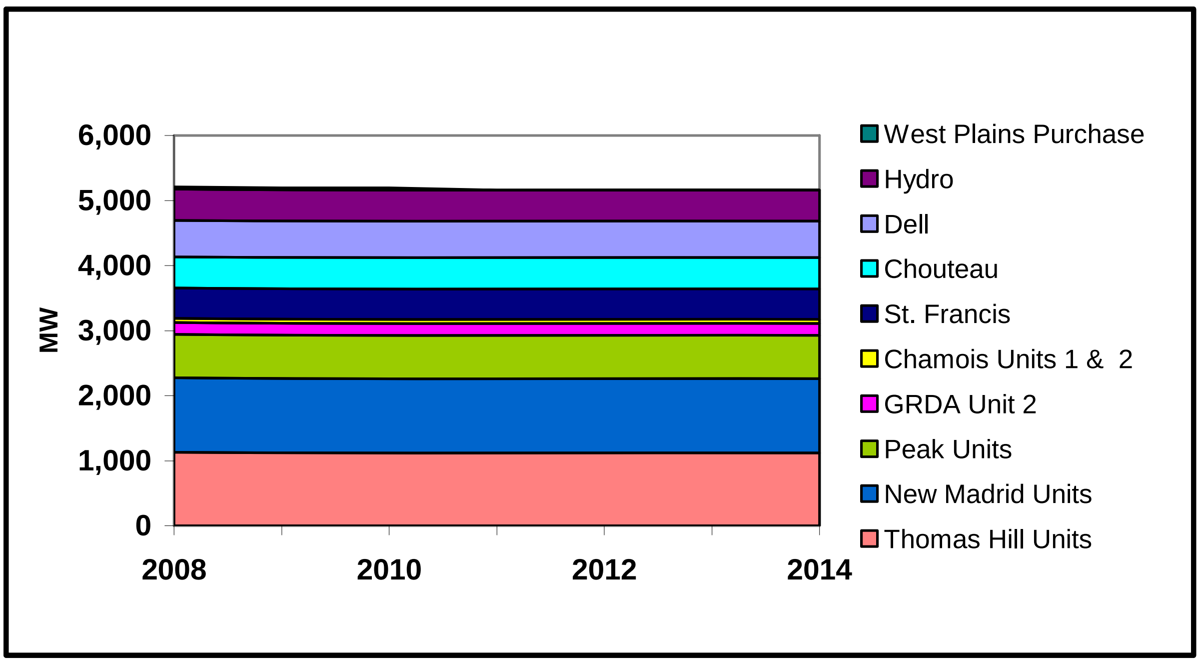
AECI has additional power purchase agreements with Southwestern Power Administration and the City of West Plains, Missouri.

Under the terms of the power purchase agreement with Southwestern Power Administration, AECI receives a firm 478 MW hydro electric capacity and a commitment for this 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 from Southwestern Power Administration which may be available each year. Since 2002, the annual supplemental energy purchases made by AECI from the Southwestern Power Administration have averaged approximately 545,000 MWh. The agreement with Southwestern Power Administration terminates on February 28, 2016.

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

The total capacity of AECI's owned and contracted generating resources are presented in Figure 4-3.

Figure 4-3 AECI System Capacity



4.3.3 Existing Demand Side Management Resources

AECI has only six G&T customers which in turn have 51 distribution customers who supply the ultimate consumer. AECI and the six G&Ts are contractually obligated to supply the power and energy demands of these ultimate consumers. In the year 2000, AECI modified its rate structure to have both peak and base demand billing components.

Using this rate structure, the demand charges are 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 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 that coincides with AECI's summer and winter peak.

In 2008, AECI will sponsor several energy efficiency programs and provide additional incentives for the participation of the member G&T and distribution cooperatives in these programs. AECI's "Take Control & Save" energy efficiency program will include the following initiatives: energy-efficient lighting, commercial energy grants, Energy Star appliances, building weatherization, electric water heating, and heating and cooling. AECI plans to continue these programs for the foreseeable future. AECI also recognizes that changes to these programs may be required as technology and legislation in these areas continues to evolve in the coming years.

Many of AECI's members participate independently in other demand-side management activities, such as 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. Most of AECI's members make literature available to their consumers regarding conservation and energy efficiency. Energy efficiency and demand side management activities of each distribution cooperative member are documented in each cooperative's respective 2000 PRS report.

4.3.4 Incremental Upgrades

Incremental upgrades include projects to increase the output from existing facilities; these increases generally relate to improvements to heat rates or plant efficiency. There are no incremental capacity upgrades considered that would meet the need for additional capacity. Under the U.S. Environmental Protection Agency's (EPA's) current regulatory interpretations, incremental upgrades can be subject to New Source Review.

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. This organization is the Southeastern Reliability Council (SERC), headquartered in Birmingham, Alabama. SERC is one of the eight regional reliability councils that make up the North American Electric Reliability Council. 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 utilities, municipal utilities, cooperatives, state and federal systems, independent power producers, and power marketers.

Because of the geographic size of the region and the diversity among its parts, SERC is divided into five sub-regions for data reporting purposes. AECI is a member of the Entergy sub-region (the companies of Entergy, AECI, and Louisiana Generating, LLC).

4.3.6 Transmission System Constraints

AECI and its member G&Ts currently have over 9,281 miles of high-voltage transmission lines with 158 interconnection points and 21 interchange agreements. 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 total member energy requirements for 2007 were approximately 19,381,700 MWh. AECI’s most recent energy forecast projects that this total will increase to over 21,200,000 MWh by 2011; this is an average annual increase of about 454,000 MWh or 2.3 percent. The total number of customers in the AECI system in 2005 was more than 828,812. According to the 2006 ELFS, this number is expected to grow to 1,015,199 by 2015; this represents an average annual increase of 2.2 percent. With AECI’s existing generating resources and forecasted peak demand requirements, AECI will have a need for additional capacity beginning in 2009. System load growth in the short-term from 2008 to 2011 is expected to be significant due to new large industrial loads that are primarily related to new pipeline and ethanol processing facilities in AECI’s members’ service areas. AECI’s peak system demand was set in August 2007 at 4,248 MW. By 2011, peak demand is projected to exceed 4,600 MW. This results in a capacity deficit of 133 MW in 2011. By 2016, the projected capacity deficit will reach 554 MW without the addition of any new generating capacity. This projected average annual load growth of over 100 MW of peak demand requirements and 454,000 MWh in energy requirements reinforces the need for new capacity and additional energy resources in the AECI’s system.

4.3.7.1 Residential

The residential class is the largest consumer class on the AECI system; it accounted for approximately 90 percent of the total number of consumers in 2005. The aggregate forecast of the number of residential consumers served by AECI’s members is expected to increase from 745,450 in 2005 to 912,614 by 2015. This equates to an average annual increase of 2.2 percent; this projected increase is slightly higher than the historical average annual rate of growth of 1.9 percent experienced from 1985 to 2005. The historic average annual growth rate excluded the impact that the addition of the Oklahoma members of KAMO Power made to the AECI system in 1998.

Sales to the residential class made up approximately 63 percent of AECI’s total sales in 2005. Energy sales to the residential sector grew at an average annual rate of slightly less than one percent during the period 2000 to 2005. The national average residential sales growth was 1.7 percent per year for the same time period. AECI’s total energy sales to the residential class are projected to grow at an average annual rate of 2.7 percent from 2005 to 2015; this represents an increase from 10,887,098 MWh in 2005 to 13,719,511 MWh in 2015. AECI’s projected rate of growth in total residential energy sales is slightly less than the 3.7 percent historic rate of growth from 1985 to 2005; AECI’s growth rate excludes the impact of sales to the Oklahoma cooperatives’ consumers.

4.3.7.2 Small Commercial

The small commercial class is defined as commercial accounts with less than 1,000-kilovolt amps (kVA) transformer capacity. AECI’s small commercial class accounts for approximately 8 percent of their total number of consumers. Typical consumers in this class include office buildings, service stations, restaurants, and other retail establishments. AECI’s number of small commercial consumers is expected to increase at an average annual rate of 2.3 percent from 66,220 in 2005 to 81,649 in 2015. The average annual growth rate from 1985 to 2005 was 3.9 percent without considering the impact of the addition of the Oklahoma cooperatives’ consumers.

Small commercial energy sales by AECI’s members accounted for 13 percent of the total sales in 2005 and have historically grown at a faster rate than residential sales. The average annual growth rate was 4.1 percent from 1985 to 2005 and excluded the impact of the Oklahoma cooperatives sales. The total amount of small commercial sales are projected to increase from the 2005 level of 2,250,280 MWh to 3,010,008 MWh by 2015; this increase represents an average annual growth rate of 3.4 percent.

4.3.7.3 Large Commercial

The large commercial class includes commercial accounts with greater than 1,000 kVA transformer capacity. In 2005, 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 1,584,383 MWh to 2,838,896 MWh from 2005 through 2015, an increase of 7.9 percent annually. This average annual growth is considerably lower than the 8.8 percent average annual growth experienced from 1985 to 2005 but higher than the 4.6 percent average annual growth that occurred from 2000 through 2005. The addition of the Oklahoma portion of the KAMO Power system is not included in these growth rate calculations.

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 9.9 percent of the total retail sales for the AECI system. The largest portion of these other sales represent direct sales by Sho-Me Power Electric Cooperative (Sho-Me Power) to municipal consumers; in 2005, Sho-Me Power's other sales represented about 72 percent of the total. Total energy sales to these other classes of consumers is projected to grow at an average annual growth rate of 3 percent from 2005 to 2015; an increase from 1,610,969 MWh in 2005 to 2,087,783 MWh in 2015. This compares to historical average annual growth of 2 percent from 2000 through 2005; once again, the impact of the addition of the Oklahoma cooperatives is excluded.

The total capacity requirements of AECI's member cooperatives is shown in Table 4-5 ; this information represents the sum of the consumer class forecasts described within preceding discussions. The total capacity requirements are projected to increase at an average annual growth rate of 2 percent. This increase compares to an average annual growth of 3.8 percent for the period 1985 to 2005 and 2.8 percent from 2000 through 2005. As before, the impact of the addition of the consumers of the Oklahoma cooperatives to the AECI system is excluded.

Table 4-5 Total Capacity Requirements

Contract Year	Coop Load (MW)	Other Loads (MW)	Required Reserve (MW)	Total Capacity Requirements (MW)
2008	4,390	8	608	5,006
2009	4,485	8	608	5,101
2010	4,595	8	608	5,211
2011	4,676	9	608	5,292
2012	4,757	9	608	5,374
2013	4,839	9	608	5,456
2014	4,920	9	608	5,537
2015	5,009	9	608	5,626

Source: AECI, 2008

4.4 NEED SUMMARY

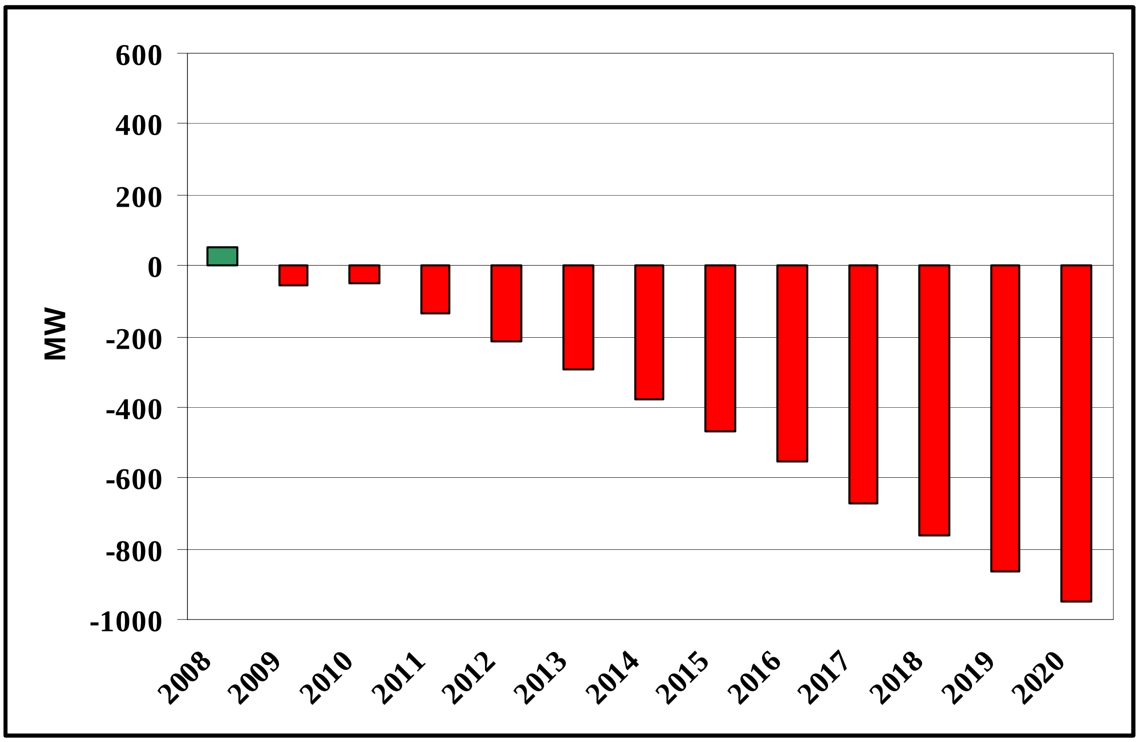
The result of AECI's most recent load study indicates that a capacity deficit of over 130 MW will occur by 2011. New intermediate generation capacity in this time frame will provide AECI with the capacity and energy necessary to serve its members' needs until such time new baseload generation is added. 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) are presented in Table 4-6. The surpluses and deficits without additional generation are shown graphically in Figure 4-4 and with the proposed combined-cycle addition in Figure 4-5.

Table 4-6 System Capacity and the Forecast Deficit Capacity

Year	Megawatts
2008	53.01
2009	-56.00
2010	-52.00
2011	-133.00
2012	-214.00
2013	-296.00
2014	-377.00
2015	-467.00

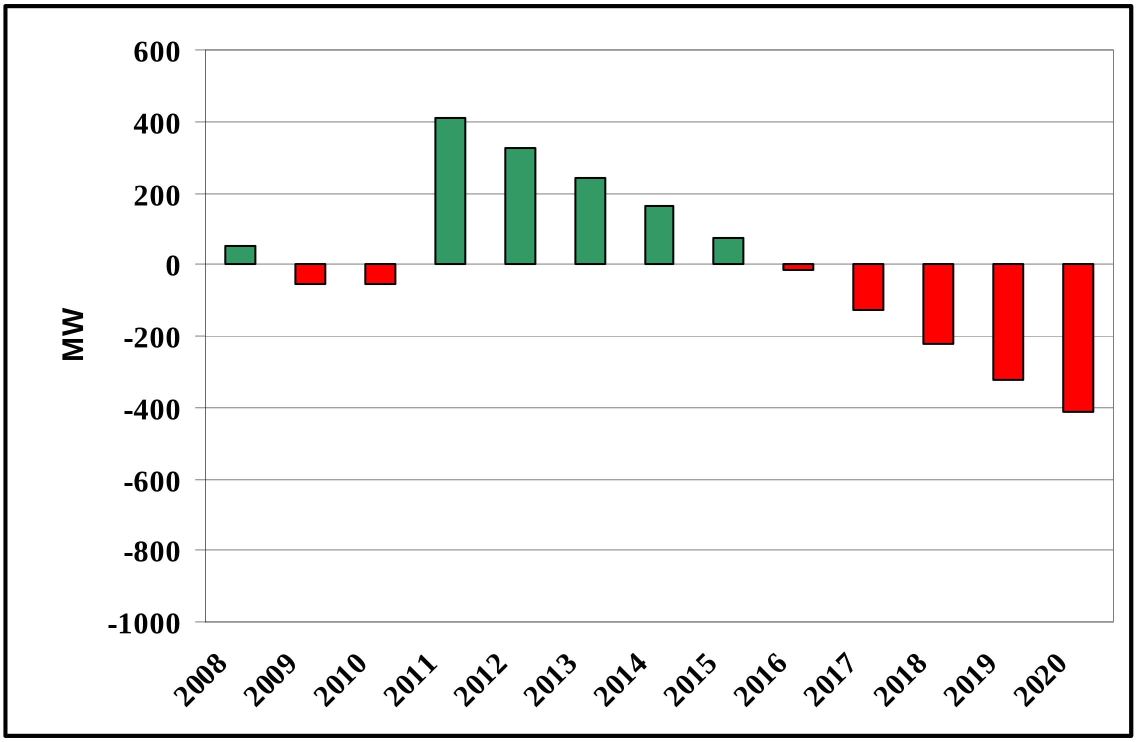
Source: AECI 2008

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



Source: AECI, 2008

Figure 4-5 AECI Projected Surplus and Deficit Capacity With Combined-Cycle Addition



Source: AECI, 2008

5.0 CAPACITY ALTERNATIVES

Several alternatives to new intermediate capacity construction were considered. Other options to provide energy or to reduce the need include load management, renewable energy utilization, distributed generation, central station generation, repowering of existing units, participation in other units, or purchase power options, and peaking units such as simple cycle combustion turbines. AECI's internet website (www.aeci.org) presents information concerning their plans to build new generation, including consideration of conservation and renewable energy resources under the topic of "Building for Tomorrow."

5.1 LOAD MANAGEMENT

As a cooperative, AECI's primary purpose is to provide low cost energy to meet the needs of its members. Consumer/members serve on the Boards of Directors for the distribution cooperatives, the G&Ts, and AECI. AECI modified its rate structure in 2000 to have both a peak and base demand billing component. This kind of demand billing structure sends appropriate price signals to and encourages the G&T members to take any cost-effective action possible to lower their peak demand at the time of AECI's summer and winter peak seasons. As discussed earlier in Section 4, AECI launched its "Take Control & Save" energy efficiency program in 2008. AECI will also sponsor several energy efficiency programs and provide incentives for participation of the member G&T and distribution cooperatives. Current plans call for these programs to continue for the foreseeable future. AECI recognizes that changes to these programs may be required as technology and legislation in these areas continues to evolve in the coming years.

Many of AECI's members participate independently in other energy efficiency activities; the most common are direct load control programs. Most direct load control programs are conducted at the distribution cooperative level. Additionally, most of AECI's members make literature available to their consumers regarding conservation and energy efficiency.

5.2 RENEWABLE ENERGY SOURCES

AECI exists for the sole purpose of providing all the energy demanded by its member-owners reliably and at the lowest cost possible. Therefore, absent specific requirements from our members, renewable resources can generally only be incorporated into AECI's generation mix when they are the lowest cost alternative. Every quarter, AECI provides its members the opportunity to purchase energy from renewable resources. To date, the demand for renewable resources has been very limited; AECI has been able to supply this energy through its own renewable generation resource.

Wind energy has developed rapidly during the past decade due in part to Federal supporting grants. Fuel costs are non-existent and the only costs are the capital costs associated with the initial installation of the equipment, including the transmission lines, and maintenance costs. The largest wind turbine manufactured in the United States generates 1.5 MW and requires space for 230-foot blade to spin freely. According to a publication from the American Wind Energy Association entitled "The most Frequently Asked Questions About Wind Energy," in open flat terrain, the land area required is approximately 50 acres per MW (AWEA 2005). Therefore, to produce 540 MW of power would require approximately 27,000 acres of land and 360 wind turbines. It is important to note that wind does not blow all of the time and cannot be the only power source without some form of power storage system or grid backup. AECI has contracted with Wind Capital Group to purchase all of the energy production from 157 MW of wind generation in northwest Missouri for a period of 20 years. Until significant advances in storage technology are realized, wind will not be a viable alternative for this project.

Solar is a resource similar to wind in that it is intermittent, and requires large land areas, and advanced storage technologies to provide an intermediate resource. However, the solar technology is not as advanced and costs are higher than wind. Solar is not a viable alternative for this project.

Biomass is the renewable resource of highest potential in the AECI service area. Conventional steam electric generation is capable of using biomass fuels to provide some or all of the energy requirements. AECI operates the Chamois plant and uses biomass fuels for a portion of that plant's heat input. AECI does not intend to design the proposed new generation facility to utilize biomass fuels for a portion of the heating requirements for the following reasons:

- Capacity is available at the Chamois plant to burn additional biomass fuels.
- Other existing units in the AECI system are better suited to biomass co-firing than the proposed unit.
- Availability of biomass fuels is seasonal and subject to frequent interruptions and variability in both quality and quantity.
- The use of biomass fuels is best suited to combustion processes such as circulating fluidized bed or stoker firing. These combustion processes are not typically available above a single unit size of 250 MW, and have a lower efficiency than some other combustion processes.

Hydroelectric resources can be more dependable, but are commonly used to supplement generation when water is available and there is a peak demand. There are several hydroelectric generating sources in the region. None of these existing facilities or planned hydroelectric resources would be able to meet the need of 540 MW. In addition, both the construction of a new dam and the operation of a hydroelectric facility can result in unacceptable environmental impacts.

In general, renewable technologies hold promise for certain applications and in certain locations; however, the available renewable energy sources are not compatible with the need for this project.

While AECI pursues renewable resources and utilizes such alternatives when they present an economic resource to serve the system's needs, for the current projected needs of AECI, renewable energy technologies do not yet provide a reliable generation source for meeting the current needs for the projected capacity requirements of the AECI system. Renewable energy technologies remain dependent on uncontrollable factors (i.e. the wind and sun) and require relatively large land areas per MW of capacity.

5.3 DISTRIBUTED GENERATION

Fuel cells, micro-turbines, internal combustion engines and battery energy storage systems were briefly considered to meet AECI's needs. Fuel cells are not currently economical on a commercial electric generation basis. Micro-turbines, while increasingly becoming an element of resource planning strategy, are not cost effective as a primary source of meeting overall customer requirements. Micro-turbines will continue to provide an option for niche power requirements where lack of transmission access, footprint limitations, and low load factor situations exist. Internal combustion engines (i.e. diesels) are used throughout the country for smaller generation needs. A large engine could produce approximately 15 MW of power, which means that over 40 such engines would need to be distributed throughout the service territory to replace the planned centralized generation of 540 MW. This source would have the disadvantage of higher fuel prices and greater emissions of some pollutants. For these reasons, none of the distributed generation alternatives are appropriate for AECI's proposed plant.

5.4 CENTRAL STATION GENERATION

The following sections apply to central station projects as opposed to distributed generation. Fossil fuels are the most cost effective fuel source for the centralized energy demand. The only alternative to fossil fuels that has been successfully demonstrated to provide the capacity and firm power required for large dependable and continuously operated centralized generation is nuclear power.

5.4.1 Oil

Oil could theoretically be used as boiler fuel in simple-cycle and combined-cycle facilities. The cost of energy using fuel oil is significantly more than natural gas, and the cost for environmental controls for burning fuel oil would be higher that the controls required for natural gas. While generally cleaner burning that coal, oil-fired generators can result in significantly greater emissions of some pollutants than with natural gas. As a result, oil-fired generation was not considered as a viable option based on the high cost of the fuel, combined with concerns related to availability, energy independence, and environmental controls.

5.4.2 Coal

Coal is the most abundant fuel resource in the United States. The U.S. Department of Energy has identified coal reserves underground in this country to provide energy for the next 200 to 300 years. While coal presents a generating resource that has a low and predictable production cost, AECI's immediate need for additional capacity could not be met by a new coal-fired generating resource due to the long lead time associated with the development of these resources. As a result, coal is not considered to be a viable alternative to this project.

5.4.3 Natural Gas

Natural gas-fired generation was evaluated and determined to be the preferred option to satisfy AECI's immediate need for additional intermediate capacity. Natural gas-fired generation can be developed by using internal combustion, such as either simple-cycle or combined-cycle combustion turbine technology, or by using external combustion such as direct firing in a boiler.

Direct firing in a boiler was rejected due to the current and projected cost of natural gas. Direct firing technology also does not offer a higher efficiency than other fuels using the same type of process.

Simple-cycle combustion turbine technology offers the lowest capital cost of the natural gas-fired generation alternatives; however, it also has the lower overall efficiency than the combined-cycle alternatives discussed below. Simple-cycle combustion turbine technology is primarily used to meet peak electrical demands.

Combined-cycle plants provide a higher level of efficiency than simple-cycle plants. The basic principle of the combined-cycle plant is to utilize the natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator; the hot exhaust gases from the gas turbine are then used to produce steam in a Heat Recovery Steam Generator (HRSG) that creates electric power with a coupled steam turbine and generator. The use of both gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and low pollutant emissions. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gas fuels to mechanical power or electricity. Modern combined-cycle plants utilizing the steam produced by the HRSG increases the efficiencies up to and, in some cases, exceeding 58 percent. Gas turbine manufacturers are continuing to develop high temperature materials and improved cooling to raise the firing temperature of the turbines and further increase the efficiency. Because of the high efficiency and relatively low capital cost of this type of resource, it is the best alternative to supply AECI's need for intermediate capacity.

5.5 REPOWERING/UPRATING OF EXISTING GENERATING UNITS

Repowering and uprating of existing generation units owned or operated by AECI is not practical or feasible to satisfy the current need for additional capacity. AECI will be evaluating each operating unit for uprating or repowering for potential additional capacity. Under the U.S. Environmental Protection Agency's current regulatory interpretations, repowering or uprating a unit would potentially subject the facility to review in accordance with the New Source Review requirements.

There are no repowering or uprating opportunities on the AECI system that have the potential to both satisfy the current need for this amount of additional capacity and to replace this needed generation in the time frame needed.

5.6 PARTICIPATION IN ANOTHER COMPANY'S GENERATION PROJECT

There are no projects known to AECI where participation was an option and adequate generating capacity was available.

5.7 PURCHASED POWER

AECI continuously evaluates the power market for cost effective opportunities to meet the power supply obligations to its members. Historically, AECI did rely on long-term power purchase contracts as part of its resource mix. However, as wholesale electricity markets have become more deregulated, transmission constraints have increased, and prices have become more volatile, purchase power agreements have become increasingly less viable.

As stated earlier, AECI's mission is to provide the lowest cost reliable power supply with as much stability as possible to its member owners. AECI has experienced situations where power supplied under long-term contracts has not been reliable. Furthermore, "long-term" in this market is less than 10 years and costs are high.

AECI has and continues to evaluate power markets for opportunities to supplement its generation portfolio. However, long-term power supply agreements are too costly and too unreliable to be a viable alternative to the proposed project.

5.8 NEW TRANSMISSION CAPACITY

AECI has an excellent transmission system with a large number of interconnections with regional power suppliers. There are no new transmission capacity additions that, in and of themselves, would provide the needed power and energy.

5.9 CAPACITY ALTERNATIVES SUMMARY

As part of its planning to meet the increasing capacity and energy demand on its system, AECI has evaluated numerous supply alternatives. As a member-owned cooperative with contractual obligations to meet its member’s requirements, certain alternates have very limited applicability. There are currently no options (such as renewables, repowering existing units, distributed and central station generation, and load management) in AECI’s service territory that would provide the needed capacity in a reliable and economical alternative to the proposed project. Other options, such as purchased power and transmission capacity additions, are too costly and unreliable. None of the options discussed above can meet the required timeframe for an in-service date of 2011. The alternative that best meets AECI's growing loads, the required timeframe, and lower costs is a natural gas-fired combined-cycle generating unit.

6.0 ALTERNATIVE SITES SELECTION

This section describes the site selection process that AECI conducted in determining a proposed location for a new, approximate 540-MW natural gas-based electric generating facility in Oklahoma to meet the needed capacity by 2011 as described in Section 4.0.

The primary purpose of the site selection study was to identify the proposed site for locating the new unit. Ultimately, the proposed site will be one that both can accommodate a new, 540-MW natural gas-based generation unit and best meets the following general criteria:

- Satisfies the requirements and guidelines of the RD
- Minimizes adverse environmental and social impacts
- Possesses the necessary physical attributes such as size and topography
- Provides access to adequate fuel and water supplies, and transmission facilities
- Allows for economical construction and operation of the proposed generating station

The identification and assessment of potential generation site areas for the project were based on the following three steps.

1. Identification and screening of potential sites.
2. Evaluation of alternative sites.
3. Selection of the preferred site.

6.1 IDENTIFICATION AND SCREENING OF POTENTIAL SITES

In 2007, AECI began searching for potential generation sites within the bounds of AECI's control area in Arkansas, Missouri and Oklahoma. The identification of potential sites was determined primarily by availability of natural gas pipelines within the project area. Sites were identify in the project area that were also in close proximity to an AECI or member system transmission line (69 kV or larger) or substation. Potential location for sites were identified along 12 natural gas pipelines–3 pipelines in Oklahoma, 7 pipelines in Missouri, and 2 pipelines in Arkansas. The available pipelines were evaluated based on available capacity and available storage. Available Storage is important for power plants in that it allows the plant to start-up with no notice to the natural gas supplier and it allows the plant to follow the system electric load. Typically, gas suppliers will load the pipeline from wells for the day. With storage on a pipeline, there is a reserve to draw from that will not upset the pipeline supply. The locations of the pipelines in Oklahoma are shown in Figure 6-1 and those in Missouri and Arkansas are shown in Figure 6-2.

Figure 6-1 Gas Pipelines in Northeast Oklahoma

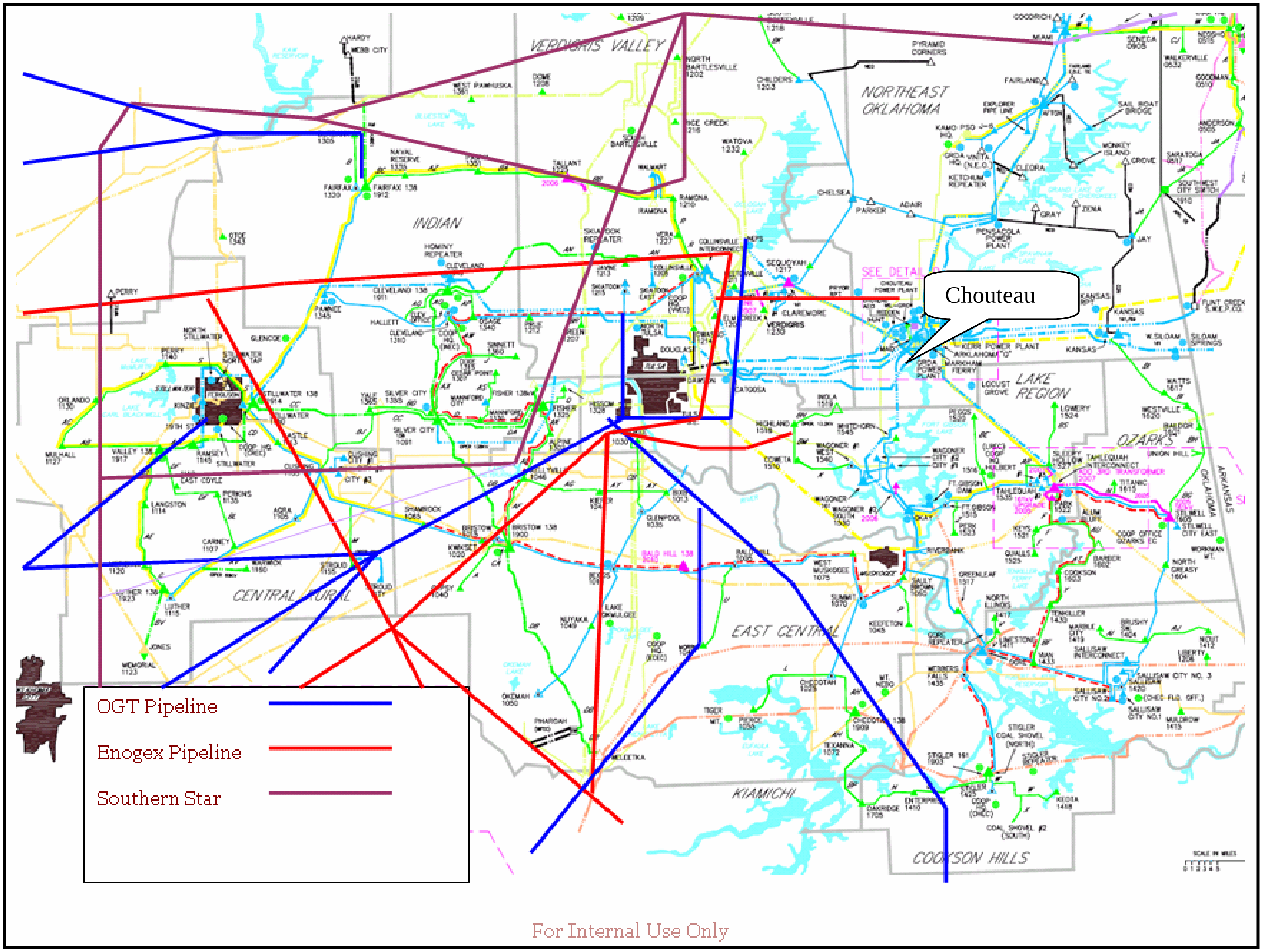


Figure 6-2 Gas Pipelines in Missouri and Arkansas

6.1.1 Oklahoma Sites

The three pipelines in Oklahoma within the bounds of AECI's control area are Enogex, Oneok Gas Transmission (OGT), and Southern Star. Enogex and OGT are intrastate pipelines with over-lapping territories and Southern Star is an interstate pipeline. Twelve sites were identified along or near these pipelines. The Port of Catoosa, Chouteau (identified in the siting study as Mid-America Industrial Park (MAIP)), Luther, Weleetka, and Claremore sites are near the Enogex and OGT pipelines. The Oolagah, Haskell/Coweta, Bristow, and Checotah sites are near the OGT pipeline. The Miami, Silver City, and

Cushing sites are near the Southern Star pipeline. The three remaining sites, the Port of Catoosa, Chouteau, and Bristow in Oklahoma, can be served by either the Enogex pipeline or the OGT pipeline,.

The Southern Star pipeline is fully subscribed, has no natural gas storage available, and would require a capital investment in excess of $100 million to add the needed firm capacity. Therefore, the Miami, Silver City, and Cushing sites were not deemed suitable.

The Bristow, Checotah, Haskell Coweta, Oolagah, Claremore, Luther, Chouteau, Port of Catoosa, and Weleetka sites were determined as potential sites for the proposed generation unit. All of the sites have firm pipeline transportation and available natural gas storage rights, as well as, access to mid-continent low cost gas commodity markets.

6.1.2 Missouri Sites

In Missouri, there is no natural gas gathering or production; however, several interstate pipelines that transverse Missouri transport gas from production zones in the midwestern United States and west Gulf Coast regions to the high demand or market regions of the northeastern United States. Long-haul pipelines are available for connecting gas-fired power plants provided that the pipeline in not fully subscribed for firm gas deliveries. The eight pipelines in Missouri are ANR Pipeline Company (ANR), Panhandle Eastern Pipeline Company (PEPL), Rockies Express (REX), Kinder Morgan Interstate Gas Transmission (KMIGT), Mississippi River Transmission (MRT), Natural Gas Pipeline Company (NGPL), Southern Star Pipeline (SSP) and Texas Eastern Pipeline Company (TETCO). Only NGPL has adequate firm delivery capability; NGPL does not have storage capacity during the winter season, which limits plant operations. There is unsubscribed capacity on the KMIGT pipeline which terminates just south of Kansas City near Peculiar; however, services are very costly, and there is no storage space to support same day gas operations. Both the PEPL and REX pipelines are fully subscribed. The REX pipeline does not have storage, and services are extremely expensive compared to other options. Therefore, none of the potential sites in Missouri have access to adequate natural gas pipelines or gas storage.

6.1.3 Arkansas Sites

The two pipelines in Arkansas are CEGT and Ozark. In northeastern Arkansas, one of the potential sites is at the existing Dell generating plant, which is located on the CEGT pipeline. The CEGT pipeline would require transmission upgrades estimated at $30 to $40 million to serve the new facility. The upgrade cost along with the annual fixed charges for firm service, make this pipeline uneconomical. The Branson area site in Arkansas would be located near the Ozark pipeline. Interconnection to this pipeline would require $60 million to interconnect and no system upgrade would be possible. Therefore, none of the potential sites in Arkansas were deemed suitable.

6.1.4 Summary Potential Sites Screening

The potential sites in Oklahoma, Missouri, and Arkansas were screened based on gas availability, gas storage, and upgrade cost for interconnection to the gas pipelines. The Bristow, Checotah, Haskell Coweta, Oolagah, Claremore, Luther, Chouteau, Port of Catoosa, and Weleetka sites were further evaluated and discussed in the Section 6.2. Table 6-1 summarizes the site screening used in the selection of the potential sites.

6.2 EVALUATION OF ALTERNATIVE SITES

The nine sites, Bristow, Checotah, Haskell Coweta, Oolagah, Claremore, Luther, Chouteau, Port of Catoosa, and Weleetka, were further evaluated based on environmental consideration such as water supply, existing land use, wastewater discharge, federally listed threatened and or endangered species, wetlands, and air quality. Only the Chouteau site had sufficient water available for a combined-cycle plant. Therefore, the Bristow, Checotah, Haskell Coweta, Oolagah, Claremore, Luther, Port of Catoosa, and Weleetka sites were eliminated from further review and the Chouteau site was carried forward as the preferred site.

The Chouteau site has sufficient water available from the industrial park for an additional combined-cycle plant. The site is currently developed as an electric generation facility and the surrounding land use is industrial. Wastewater from the existing plant is discharged to the Neosho River and any additional discharges from a new facility would also be discharged to the river. No impacts to the river are anticipated from the increased discharge. Being the site has been previously disturbed, the potential for threatened and endangered species at the site are minimal. There are known wetlands at the site, but the small size and location of these wetlands indicate space is available for the new generation facility. The site is in an air quality attainment region in Oklahoma.

6.3 SELECTION OF PREFERRED SITE

Based on all available options known at this time, AECI identified the Chouteau site, next to the existing Chouteau power plant, as the preferred site to construct the new generation facility. It is also the best site

Table 6-1 Screening of Potential Sites

State	Sites	Natural Gas Pipeline	Natural Gas		
			Availability	Storage	Upgrade Cost
Oklahoma	Bristow	Enogex/OGT	Adequate	Adequate	$2 mm to interconnect, no system upgrades needed
	Checotah	OGT	Adequate	Adequate	$15 mm to interconnect, no system upgrades needed
	Haskell/Coweta	OGT	Adequate	Adequate	$2 mm to interconnect, $25 mm in upgrades
	Oolagah	OGT	Adequate	Adequate	$2 million to interconnect, $45 mm in upgrades
	Cushing	Southern Star	Fully subscribed	None	$2 million to interconnect, $50 mm in upgrades
	Miami	Southern Star	Fully subscribed	None	$2 million to interconnect, $100 mm in upgrades
	Silver City	Southern Star	Fully subscribed	None	$2 million to interconnect, $100 mm in upgrades
	Claremore	Enogex/OGT	Adequate	Adequate	$2 million to interconnect, $40 mm in upgrades
	Luther	Enogex/OGT	Adequate	Adequate	$10 mm to interconnect, no upgrades needed
	Chouteau (MAIP)	Enogex/OGT	Upgrades required	Adequate	$2 million to interconnect, $40 mm in upgrades
	Port of Catoosa	Enogex/OGT	Upgrades required	Adequate	$2 million to interconnect, $40 mm in upgrades
	Weleetka	Enogex/OGT	Firm	Adequate	$2 million to interconnect, $25 mm in upgrades
Missouri	Centralia	PEPL	Fully subscribed	None	$2 mm to interconnect, no upgrades possible
	Chamois	PEPL	Fully subscribed	None	$15 mm to interconnect, no system upgrades possible
	Holden	PEPL	Fully subscribed	None	$2 mm to interconnect, no upgrades possible
	Centralia	Rockies Express	Fully subscribed	None	$2 mm to interconnect, no upgrades possible
	Poplar Bluff	MRT	Inadequate	None	$10 mm to interconnect, no upgrades possible
	Poplar Bluff	NGPL	Adequate	None	$5 mm to interconnect, no system upgrades needed
	St. Francis	TETCO	Fully subscribed	None	$3 mm to interconnect, no upgrades possible
	Peculiar	KMIGT	inadequate	None	$3 mm to interconnect, no upgrades possible
	Watson	ANR	Fully subscribed	None	$70 mm to interconnect, no system upgrades possible
Arkansas	Branson Area	Ozark	Upgrades required	None	$60 million to interconnect, no system upgrade possible
	Dell	CEGT	inadequate	None	$1 mm to interconnect, no system upgrades possible

from an operational standpoint, due to the proximity, and the availability of natural gas storage rights. Without this storage access, intra-day operations would be difficult. AECI received full proposals for pipeline interconnection and upgrades from both Enogex and Oneok for the Chouteau site in June 2007.

6.4 SITE DESCRIPTION

The Chouteau Site is located in Mayes County, Oklahoma, in the MAIP. The site consists of approximately 17 acres located 3.6 miles northeast of Chouteau, Oklahoma to the east of U.S. Highway 69. Access to the plant is from State Highway 412B. The Chouteau site is located approximately 36 miles east of Tulsa, Oklahoma, 33 miles north of Muskogee, Oklahoma, and 30 miles south of Vinita, Oklahoma (Figure 6-3). The area surrounding the plant is primarily industrial to the north and agricultural with sparse residential use to the east and south.

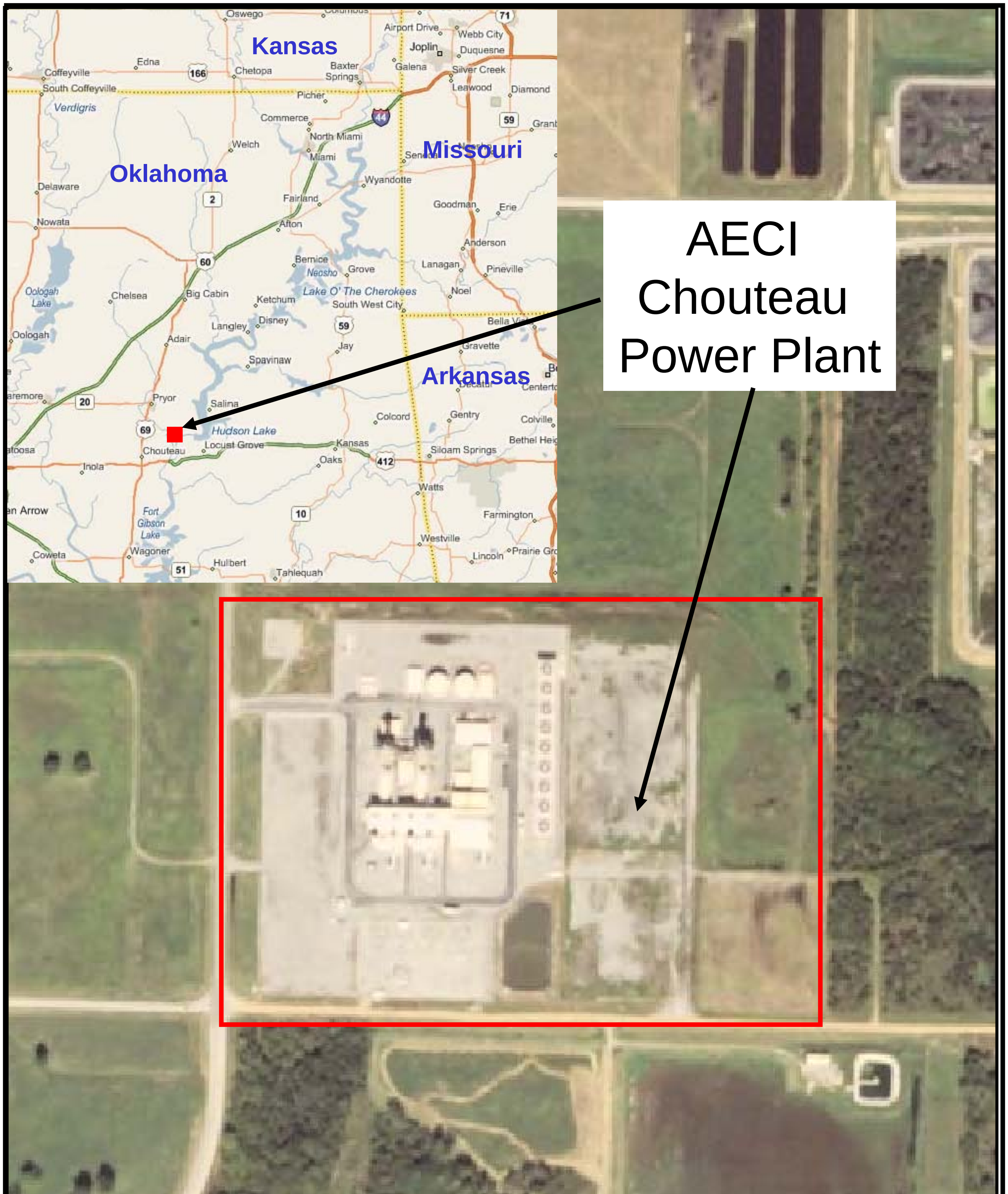
The water supply source at the Chouteau Site will be supplied by an existing water supply line extending to the Neosho River, which is approximately 2 miles northeast of the site. The water will be used in the cooling tower, for service water needs such as fire protection and equipment cooling, for drinking water and treated further to achieve ultra-pure water for the boiler.

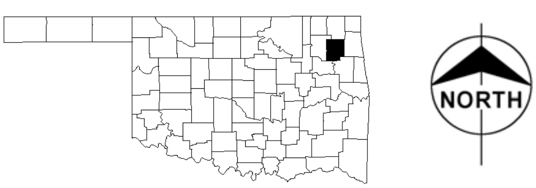
6.5 PROJECT DESCRIPTION

Design of the project has not been completed. The following sections generically describe the major components of the proposed electric generating facility, the proposed air quality emission controls, transmission requirements, fuel use and waste disposal, water supply and wastewater disposal, the operating characteristics of the proposed unit, the expected noise levels construction and operation, transportation system to be utilized during construction and operation. The project schedule, project costs and employment requirements are also presented.

6.5.1 Facility Equipment and Layout

The facility will employ industrial frame advanced technology CTs equipped with dry low-nitrogen oxide (NO_x) combustors. Each combustion turbine (CT) will be furnished with all accessories and auxiliary systems required for startup and generating capability for combined-cycle operation. Each CT will incorporate an air inlet system with specially designed equipment and ducting to modify the quality of air under various temperatures, humidity, and contamination situations to make it more suitable for use. The self-cleaning inlet air filter will utilize high efficiency media filters. In addition, a moisture separator will be used to remove water spray and mist from the incoming air stream. Either a recirculating hydrogen gas stream cooled by gas-to-water heat exchangers or water-to-air heat exchangers will cool the turbine





Burns & McDonnell
SINCE 1898

Figure 6-3
Approximate
Chouteau Site Location

generators. An on-site water supply will be used to supply cold water for the inlet air chiller system for CTs to enhance power generation during warm weather. The inlet air ducts will also have noise attenuation features.

One of the significant features of a combined-cycle plant is the use of the hot exhaust gas from the CT to produce steam which, in turn, is expanded in a steam turbine generator to drive an electric generator to produce electricity. The HRSG is the key piece of equipment necessary for the production of this steam. The HRSG unit is designed to fully integrate with the combined-cycle plant and includes the required inlet-outlet ductwork, structural supports, piping and accessories. The location of the equipment on the proposed project site is presented in Figure 6-4.

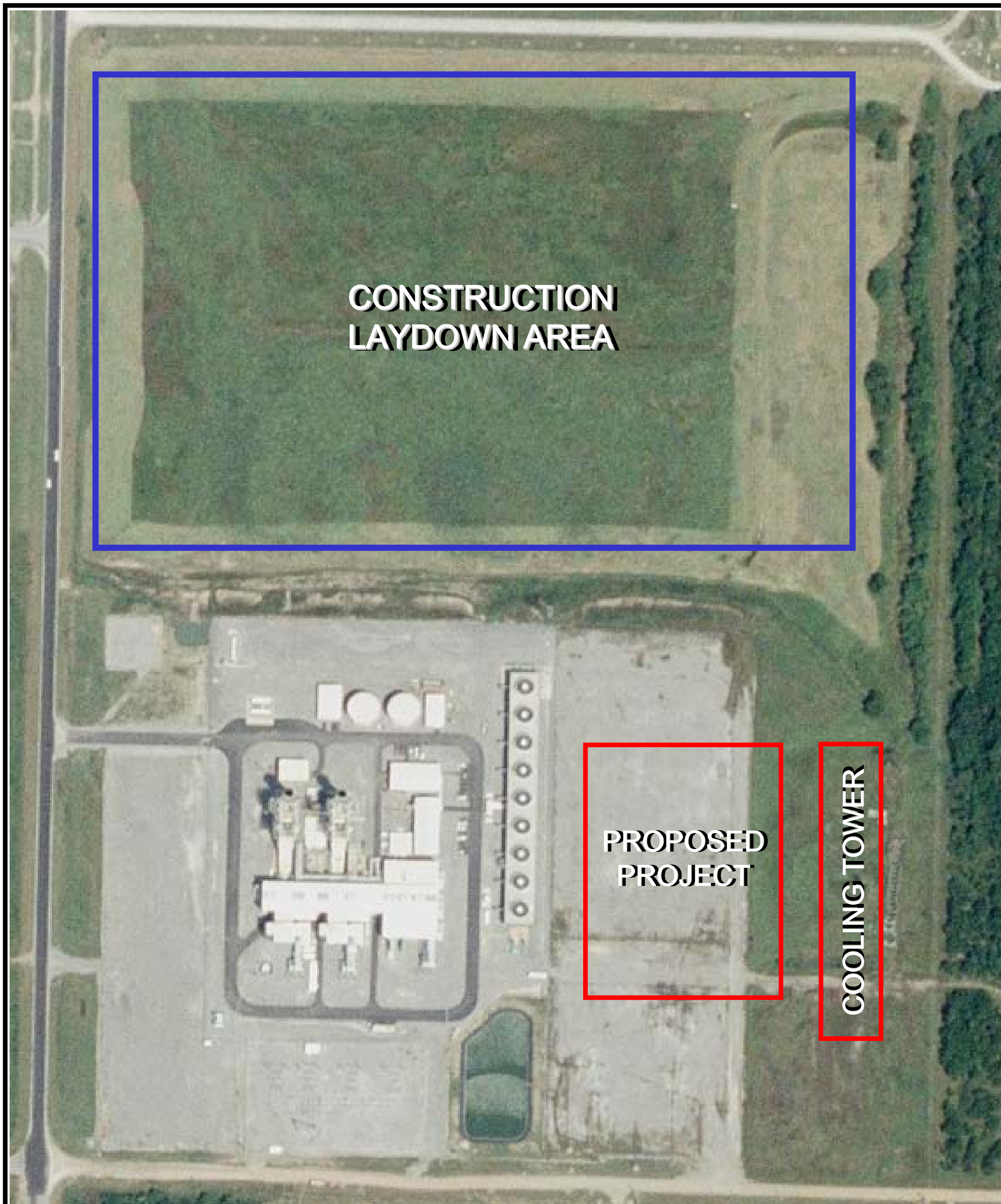
6.5.2 Emissions Controls

The proposed combined-cycle plant will reduce NO_x emissions by the use of dry, low NO_x combustion technology in the CTs while firing natural gas. Because natural gas does not contain appreciable amounts of sulfur, the sulfur dioxide emissions will be minimal while firing natural gas. The control of carbon monoxide (CO) and volatile organic compounds will be achieved through combustion controls in the CT. The combination of clean burning fuel and good combustion practices will be used to achieve control of particulate matter.

A monitoring system for airborne emissions will be installed in the stack. This system will be a Continuous Emissions Monitoring System (CEMS) as required pursuant to 40 Code of Federal Regulations (CFR), Parts 60 and 75.

6.5.3 Transmission Requirements

The proposed Chouteau 540 MW generating project will be connected to a new 161/345-kV substation that will serve both the existing and proposed Chouteau generating facilities. This substation will be located approximately two miles east of the Chouteau Power Plant on 16.7 acres. An approximate two mile single circuit 161-kVtransmission line would be constructed from the existing Chouteau Power Plant to the new 345/161-kV substation. For outlet capability from the project a new, approximate 1.3 mile, single circuit 345-kV line will be constructed to the nearby Grand River Dam Authority (GRDA) Coal-Fired Power Plant. This connection will allow for the full outlet capacity of the new 540-MW generation project. A second 345 kV transmission line is proposed from the new 161/345 kV substation, this line will be a 100-mile kV transmission line for the KAMO POWER system terminating at a new substation, Blackberry 345 kV Substation, near the Kansas-Missouri border west of Jasper, Missouri in Jasper County. KAMO POWER is currently seeking RUS approval for construction of the 100-mile 345 kV



Proposed Project & Cooling Tower

Construction Laydown Area

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Figure 6-4
Preliminary Site Plan

transmission line project. A Draft Environmental Assessment on the transmission line project has been provided to the public for comment. The new 161/345-kV substation that will serve the Chouteau plant will be included in the Chouteau power plant expansion project.

6.5.4 Fuel

Natural gas will be the fuel for the new unit. The fuel system will interconnect to a proposed new gas meter and regulation station located on the plant site. The gaseous fuel system will include fuel gas heaters, meters and an isolation system designed using the appropriate industry standards and construction codes. As noted in the siting study, Enogex and OGT are both near the Chouteau site and would require some upgrades to their systems to serve the additional firm capacity. Enogex currently supplies natural gas to the existing Chouteau Power Plant; however, the existing pipeline does not have the required capacity. For the new generation facility, Enogex would construct 38 miles of pipeline from an existing line in eastern Wagoner County to the MAIP. In addition, Enogex would require upgrades to looping and compression work near Oklahoma City. The Enogex pipeline will be upgraded from Oneta, Oklahoma (Wagoner County on Highway 51) to the plant site. OGT would construct a 45-mile pipeline from near Haskell, Oklahoma to the MAIP for the proposed generation facility. Figure 6-5 shows the approximate alignments of each pipeline as based on the potential endpoints; final right-of-way alignment will be determined through the pipeline permitting process. AECI will not construct, permit, or own the pipeline and is not requesting RUS funding for the pipeline. The pipeline would have the potential to serve future occupants of the MAIP.

6.5.5 Water Supply and Wastewater Disposal

The existing water supply source will be used for potable uses and service water needs, and will provide makeup to the demineralizer system.

Wastewater generated at the site includes the demineralizer system discharges, blowdown from the HRSG, and some storm water runoff. Either the existing wastewater treatment system may be used or a new system may be constructed. This wastewater system will be operated to provide solids settling, pH adjustment, oil and grease removal, and some trace metals reduction. The plant is currently authorized to discharge under the terms and conditions of a National Pollutant Discharge Elimination System (NPDES) Permit. The proposed expansion of the existing wastewater treatment system would effectively double the amount of effluent discharged to the Neosho River. A reasonable potential analysis to evaluate the impacts of the proposed expansion on the facility’s NPDES permits was completed. Based on this analysis, no change to the facility’s permit is expected with the exception of an increase in the loading

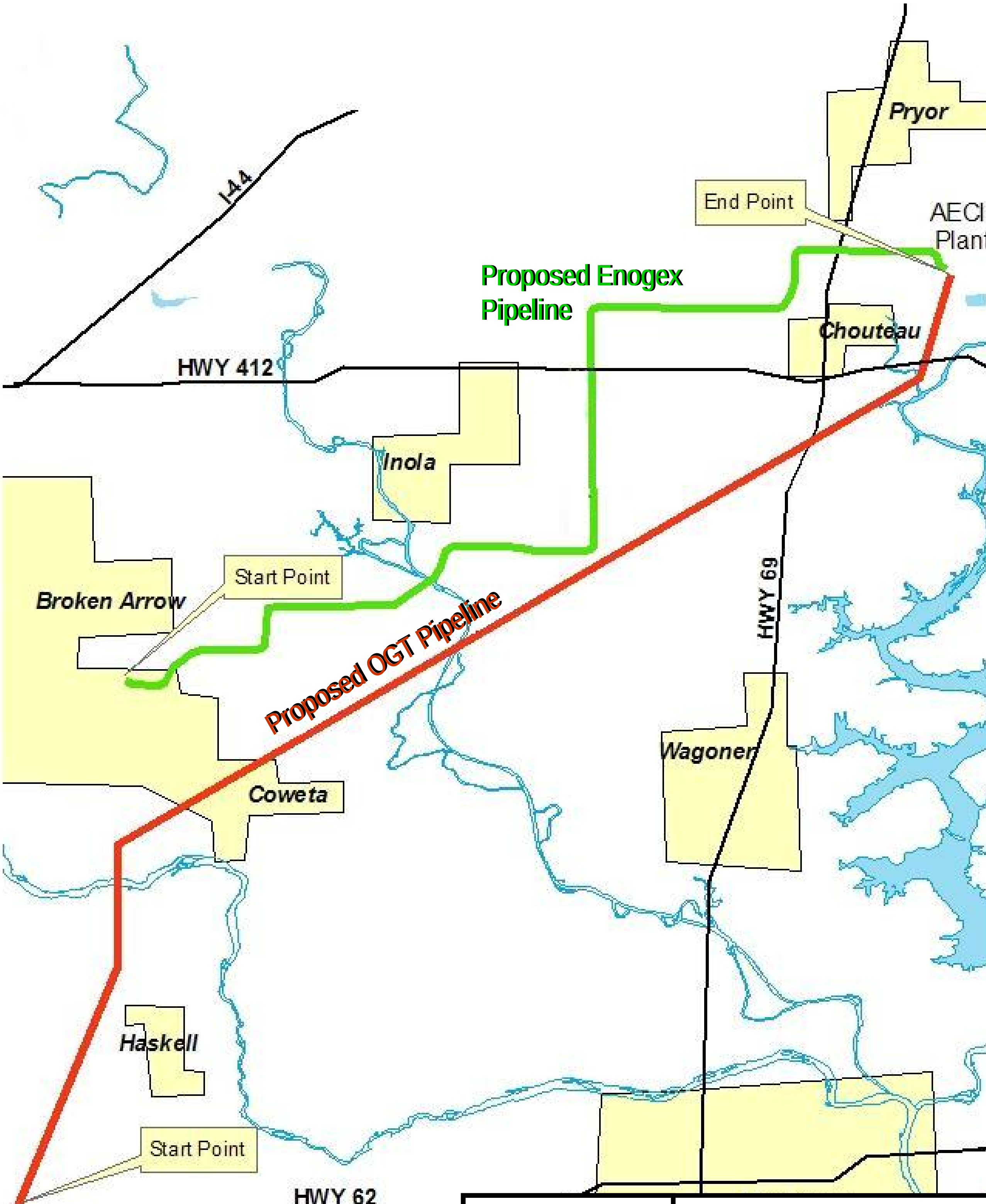

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Figure 6-5
Approximate
Pipeline Alignments

limit for FAO proportionate to the increase in flow discharged. The proposed expansion should not result in a reasonable potential to exceed applicable water quality criteria. Furthermore, the bio-monitoring and background monitoring requirements in the current permit should not affected by the proposed expansion.

6.5.6 Operating Characteristics

The plant is expected to typically operate at an annual capacity factor of less than 40 percent. Plant operations are monitored for staff safety, meeting environmental requirements, and providing reliable and efficient operations while striving to achieve power output objectives, limiting emissions, and minimizing fuel and other consumables.

6.5.7 Transportation

Existing roads will be used for construction access to the site. No upgrades to off-site roads are anticipated. Construction traffic will include all craft labor, construction management staff, contractors, contractor equipment, vendors, and material and equipment deliveries. In addition to road vehicular traffic, the existing rail facilities will be utilized occasionally for delivery of large equipment. The frequency of the daily auto traffic will be proportionate to on-site labor projections.

In addition to the normal vehicle auto traffic, deliveries of construction materials can average between 15 and 25 large trucks a day. Special deliveries, for such items as structural steel and concrete, may occasionally exceed 50 deliveries on a given day. However, truck deliveries during the day under normal conditions should not coincide with the early morning or late afternoon labor vehicle traffic.

Traffic impacts associated with the additional site construction traffic will most likely occur around the starting and quitting times of the construction craft labor when vehicle traffic will be at its peak. The amount of added traffic will also be dependent on the phase of construction. It will start moderately and continue to increase until the peak period of construction. Additional traffic caused by material deliveries will be of lesser impact as they are typically intermittently spread throughout the day. There will be exceptions when truck traffic will significantly increase for a given day due to a special construction process. Permits and/or fees may be required for new driveways or access roads off of county roads, impacts to arterial roads, and for upgrading portions of county road rock-gravel to pavement. The Oklahoma Department of Transportation will be contacted for guidance on the permits, fees, and upgrades for the local roads.

6.5.8 Project Cost and Permits

The current capital cost estimate during construction is approximately $434 million. The initial project engineering will occur in 2008 and procurement and construction would span from January 2009 to April 2011. A list of potential permits, approval, and authorizing actions for the project are shown in Table 6-3.

6.5.9 Project Work Elements

The following sequence provides the anticipated order of construction:

- site preparation
- underground utilities installation
- start foundation installation
- start building steel erection
- start boiler erection
- start air quality control equipment erection
- start turbine erection
- start balance of plant mechanical erection
- start electrical construction
- perform plant startup and initial operation activities
- commercial operation

The construction activities will be sequenced according to an overall project schedule.

6.5.10 Employment

Based on similar type projects, the construction force will consist of mostly pipefitters, electricians, iron workers, and carpenters. A maximum of 200 to 225 people could be working during the peak construction period at the facility. All construction activity is expected to be completed within 24 months. The operational staff will be approximately 25 to 33 employees.

Table 6-2 Federal, State, Local Permits, Approvals, and Authorizing Actions

ISSUING AGENCY	PERMIT/APPROVAL NAME	NATURE OF PERMIT	AUTHORITY
Federal Government			
Federal Aviation Administration	Notice of Proposed Construction or Alteration	Structure location and height relative to air traffic corridors	49 United States Code (U.S.C.) 1501; 13 CFR §77, Objects affecting navigable air space
U.S. Environmental Protection Agency	Title IV Acid Rain Permit	This permit requires monitoring and reporting so as to comply with sulfur dioxide allowances	40 CFR §72
U.S. Army Corps of Engineers	Section 404 Permit (Clean Water Act) Nationwide Permit/Individual Permit	Controls discharge of dredged or fill materials in wetlands and other waters of the United States	Section 404 of the Clean Water Act (33 CFR §323.1)
U.S. Fish and Wildlife Service	Threatened and Endangered Species Clearance	Clearance from the agency that federal listed protected species and/or their habitat will not be impacted	Endangered Species Act (16 USC §1531 et seq.)
State Government			
Oklahoma Department of Environmental Quality (ODEQ)	Wetland or Dredge and Fill Approval (Section 401 Water Quality Certification)	Review of potential adverse water quality impacts potentially associated with discharges of dredged or fill materials in wetlands and other waters of the United States	Section 401 of the clean Water Act
ODEQ	Oklahoma Pollutant Discharge System (OPDES) Storm Water Discharges associated with Construction Activities	Apply for coverage under General Permit to authorize storm water discharges to Oklahoma surface waters associated with the construction of the Project	Section 402 of the Clean Water Act
ODEQ	NPDES Storm Water Discharges associated with Facility Operation and SWPPP	Apply for coverage under General Permit to authorize stormwater discharges to Oklahoma surface waters associated with the operation of the Project	Section 402 of the Clean Water Act

ISSUING AGENCY	PERMIT/APPROVAL NAME	NATURE OF PERMIT	AUTHORITY
ODEQ	OPDES Oklahoma State Construction and Operating Permit	Apply for coverage under Individual Permit to authorize construction of treatment works and industrial and storm water discharges to Oklahoma surface waters associated with the Project	Section 402 of the Clean Water Act
ODEQ	General Wastewater Discharge Permit for Hydrostatic Test Projects No. OKG270000	Permit for discharging waters associated with hydrostatic testing of pipelines and storage tanks	Section 402 of the Clean Water Act
ODEQ	Prevention of Significant Deterioration (PSD) Permit	Permit to construct, install and operate a major emission source in Oklahoma. Typically consist of Best Achievable Control Technology, Air Dispersion Analysis, and Air Quality Related Values Analysis.	40 CFR §52.21
ODEQ	Title V Operating Permit	Permit for operation of major equipment or major facilities that may directly or indirectly cause or contribute to air pollution	
Oklahoma Department of Wildlife Conservation	Threatened & Endangered Species Clearance	Clearance from the agency that state listed protected species and/or their habitat will not be impacted by the project	State Endangered Species Program
Oklahoma Historical Society State Historic Preservation Office (SHPO)	Section 106 of the National Historic Preservation Act Consultation with Tribal Historic Preservation Officer	Consult with project applicants and state agencies regarding impacts on cultural resources that are either listed or eligible for listing on the National Register of Historic Places	National Historic Preservation Act
Local Government			
Mayes County Planning & Zoning Office	Special Use Permit/Rezone from agricultural to industrial Building Permit Entrance Permit Transportation Fee	Obtain county rezoning approval prior to construction Permit to construction buildings Permit for driveway or access road off of county road Fee for impacts to arterial roads	To Be Determine (TBD)

7.0 References

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