2.0 ALTERNATIVES INCLUDING THE PROPOSED ACTION

2.1 INTRODUCTION

As discussed in *Section 1, Introduction*, AECI has determined a need for approximately 660 (megawatts) MW net of additional baseload electric capacity to meet the needs of its cooperative members. AECI can meet this need by acquiring the power from outside sources, or by building its own facility (self-build option).

2.1.1 Evaluation Procedure and Results

After a comprehensive evaluation in accordance with the Council on Environmental Quality (CEQ) regulations (see text box at right) – and following the guidance set forth by U.S. Department of Agriculture, Rural Development (USDA/RD) to prospective loan recipients – AECI concluded that owning its own source of electric generation best meets the project purpose and need. AECI then evaluated self-build alternatives and then conducted a site selection analysis for a proposed facility. As a result of these analyses, AECI proposes to construct a 660 MW net coal-fired power plant at a site near Norborne, Missouri. This Proposed Action would also include construction of approximately 134 miles of 345-kV transmission lines and about 7 miles of new rail lines for delivery of coal and other materials to the plant, in addition to several other connected actions.

Council on Environmental Quality and Environmental Policy Act

Council on Environmental Quality (CEQ) regulations (Title 40 Code of Federal Regulations [CFR] Parts 1500-1508) require that the USDA/RD use the review process established by the National Environmental Policy Act (NEPA) as amended to evaluate not only the Proposed Action, but also to identify and review reasonable alternatives to the Proposed Action, as well as a "No-Action" Alternative. The No-Action Alternative means the proposed project would not take place. The No-Action Alternative provides an environmental baseline against which impacts of the Proposed Action and alternatives can be compared. CEQ (1981) states that reasonable alternatives include those that are practical or feasible from a common sense, technical, and economic standpoint. CEQ requires this document to identify those alternatives that have been eliminated from further analysis, and briefly discuss the reasons why they have been eliminated (40 CFR 1502.14(a)). This comprehensive review ensures that environmental information is available to public officials and citizens before decisions are finalized and before actions are taken.

The discussion of the alternative evaluation is organized as follows:

- Alternatives considered but eliminated from detailed consideration
- Alternatives assessed in detail
- Description of the Proposed Action

Reasonable alternatives are fully evaluated and presented in comparative form in *Section 3, Affected Environment and Environmental Consequences*, along with the Proposed Action, and the No Action Alternative, as required by CEQ regulations.

2.1.2 Summary of Alternatives Considered

2.1.2.1 Power from Outside Sources

AECI considered contracts to purchase power from other existing or planned sources, as well as agreements to participate in another company's planned project. Options in these categories are discussed in *Section 2.2.1, Power Purchase Agreements*.

2.1.2.2 Self-Build Alternatives

The self-build option first involves an evaluation of power generation technology alternatives, then an evaluation of siting alternatives.

2.1.2.2.1 Technology Alternatives

Except for photovoltaics, which produce electricity directly from sunlight, commercial electricity is produced by a shaft wrapped with wires that turns in a magnetic field (a generator, Figure 2-1).

The action of spinning of conductors in the magnetic field produces an electric current in the wires.

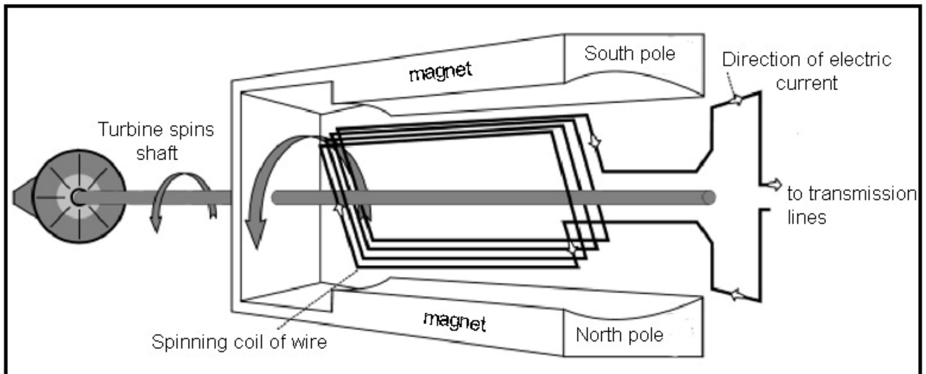

Figure 2-1. Electric Generator

Source: EIA, 2004a

A turbine spins the generator shaft (left side of Figure 2-1). A typical turbine consists of a shaft fitted with blades to present a surface for the driving force to push against. The basic choices in electric power generation alternatives are in the options for the force that drives the turbine. The current technology options are:

- Air (wind)
- Water (hydroelectric)
- Combustion of a fluid (natural gas, other gases, petroleum)
- Steam

For the steam option, the choice of the heat source used to create the steam provides further alternatives:

- Combustion of coal
- Combustion of other organic materials
- Nuclear reaction
- Concentrated solar energy
- Geothermal energy

AECI evaluated all these alternatives for producing electricity to meet its needs.

Load Types and Alternatives

Power generation options like hydroelectricity and simple-cycle combustion (the expansive force from combustion of a gas is used to drive a combustion turbine) are best suited for peak loads, since they can provide relatively quick energy (think of starting a car or turning on a faucet.) See *Section 1, Introduction*, for a discussion of base, intermediate, and peak loads. Steam options are best suited for baseload, because of the time and energy required to produce the steam. Combined-cycle plants (the force from combustion of a gas is used to drive a combustion turbine, and then the heat from combustion is used to create steam to drive a steam turbine) are in between and are often used for intermediate loads. Baseload power sources also need to be “firm,” which means that they need to have high reliability and be able to produce the power when the utility needs it (DOE, 2004a).

Figure 2-2 shows the U.S. 2005 distribution of power sources for electricity generated from electricity-only power plants in the electric power sector.[3]

Coal provided over half of the electric energy produced, and the three steam-based energy sources of coal, nuclear, and natural gas together provided almost 90 percent of the energy. Included in the "Other" category are: petroleum, 3 percent; biomass – wood, 0.2 percent; biomass – waste, 0.5 percent; and geothermal, 0.4 percent. Other categories represent less than 0.1 percent each. The change in U.S. use of energy sources for electricity, and the increase of electrical use over time, is shown in Figure 2-3.

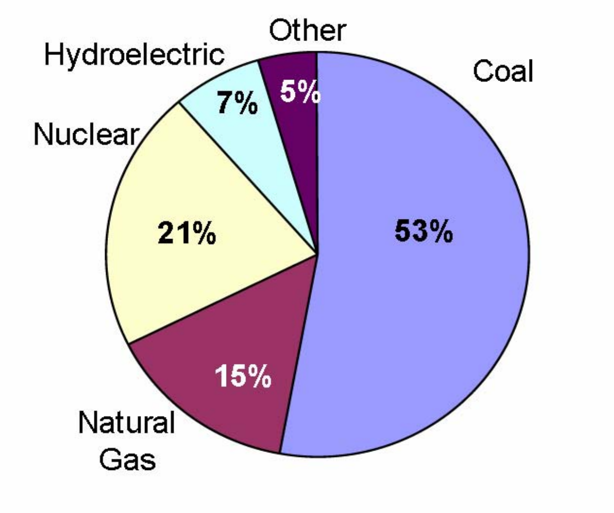

Figure 2-2. Net Electricity Generation US 2005 Electric Power Sector, Electricity-Only Plants

Source: EIA, 2006b

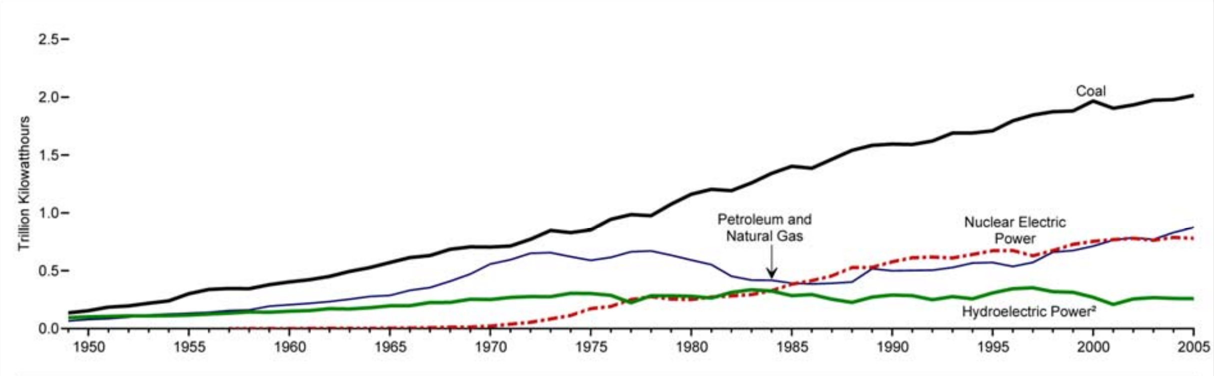

Figure 2-3. US Trends in Major Electricity Sources, 1949 to 2005

Source: EIA, 2006b

[3] Combine-heat-and-power (CHP) plants are not included, except for a small number of electric utility CHP plants. In the remainder of this chapter, the electricity produced by these electricity-only power sector plants is generically referred to as the US electric generation.

2.1.2.2.2 Siting Alternatives

Centralized Generation Site

The evaluation of centralized generation sites follows the evaluation of technology alternatives.

Distributed Power Generation

Distributed Power Generation is the practice of placing small (5 to 5,000 kW) (Resource, 2001) units capable of providing on-site electricity and heat at the location demanding those needs. The means of providing electricity include reciprocating engines, micro-turbines, fuel cells, photovoltaic, run-of-the-river hydroelectric, and windmills. Most of these technologies are discussed further in this section; however, since the small scale application of distributed power generation is applicable to all of them, it is introduced here.

There would be a number of challenges if AECI were to replace a 660 MW net centralized baseload power generation plant with a distributed generation network. AECI would have to partner with hundreds of individual power users to co-locate these units at the power users' facilities. It would take considerable time and effort to find candidate sites and then put into place the legal instruments for implementation. AECI would have to engineer each site individually to ensure the applied generation technology fits the needs of the facility. AECI would then have to obtain the necessary environmental and building permits for hundreds of sites, each of which would require individual permits. Ongoing operation and maintenance of these generation units along with meeting monitoring, recordkeeping, and reporting for hundreds of units would be a complex task. The total cost would far exceed the cost of a comparable single baseload unit (Resource, 2001).

For these reasons, AECI has determined that implementing a distributed power generation network, initiated, constructed, and maintained by AECI is not feasible.

2.2 ALTERNATIVES EVALUATION

This section discusses all alternatives that were evaluated, and for those that were eliminated from detailed consideration, provides the rationale for their elimination.

AECI has been evaluating power options for several years. Since the electric utility industry, relevant laws and regulations, and available technologies are constantly changing, alternatives and decisions are routinely re-assessed. The alternative discussions in this document include up-to-date information on the alternatives considered.

2.2.1 Power Purchase Agreements

The governing regulations for USDA/RD loan applications[4] allow generation loans only under the following conditions:

i. Where no adequate and dependable source of power is available to meet the consumers' needs; or

ii. Where the rates offered by other power sources would result in a higher cost of power to the consumers than the cost from facilities financed by RUS [Rural Utilities Service], and the amount of the power cost savings that would result from the RUS-financed facilities bears a significant relationship to the amount of the proposed loan.[5]

As part of its planning process and in accordance with USDA/RD governing regulations, AECI advertised their request for proposals for long-term power supply up to 600 MW in three industry publications in April 2004.[6] AECI received nine responses from five companies (AECI, 2004d).

Three responses proposed options other than power purchase agreements. Summit Power NW, LLC proposed to work with AECI to locate, develop, and contract the construction of a plant to provide the required power. This was a service AECI did not need, as it offered no benefit, cost or otherwise, to the self-build option. NRG Energy offered to sell a used and stored 563 MW

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[4] These regulations can be found in the Code of Federal Regulations, Title 7, Section 1710 (7 CFR 1710).
[5] 7 CFR 1710.254(a)
[6] *Transmission and Distribution World, Power,* and *Power Engineering.* Note that in April 2004, the estimated need was 600 MW. This was later increased to 660 MW.

generator/turbine. This also was not an alternative to constructing a new facility. Peabody Energy offered joint ownership of up to 500 MW of the Prairie State plant. This alternative is discussed in the subsection entitled *Participation in Another Company's Project*, below.

FPL Energy, LLC submitted two proposals, both of which offered to sell output from wind farms in Kansas. Neither proposal was a viable alternative to a self-build option, as the wind output is not firm and does not provide reliable baseload capacity (see discussion of wind power in *Section 2.2.3.3, Wind*).

Four of the proposals offered potentially viable power purchase agreements:

1. NRG Energy offered a 15-year toll on its Audrain 7-unit, 640 MW simple cycle gas turbine (SCGT) plant near Vandalia, MO: NRG Energy would own and operate the plant leaving AECI with the responsibility of fuel delivery and delivery of power to AECI's system.

2. Keeney Creek Energy Associates, an affiliate of LS Power Associates, offered an eleven to fifteen year power purchase agreement for 300 to 600 MW of coal fired generation at its Keeney Creek plant near Kansas City, MO. The plant could be directly connected to AECI's system, but AECI would be responsible for all transmission requirements.

3. Plum Point Energy Associates, another affiliate of LS Power Associates, offered an eleven to fifteen year power purchase agreement for 300 to 600 MW of coal fired generation at its Plum Point plant near Osceola, AR. The plant would not be connected to AECI's system, and AECI would be responsible for all transmission service arrangements including any needed upgrades and charges to get power to AECI's service area.

4. Peabody Energy offered a 15-year power purchase agreement for up to 500 MW of a 1500 MW coal fired plant in Marissa, IL. AECI would be responsible for all transmission requirements.

AECI compared costs for each of these four options with the self build option through the year 2025, as summarized in Table 2-1. The analysis includes the cost of energy delivered to AECI's system. Therefore, the purchase agreement options include transmission costs but the self-build option does not. All purchase agreement options were higher in cost than the self-build option.

Table 2-1. System Cost Present Value 2004 $ (Millions)

Option	**Base**	**1**	**2**	**3**	**4**
Year	Self Build	Audrain	Keeney Creek	Plum Point	Peabody
2004	$174.25	$174.25	$174.25	$174.25	$174.25
2005	$191.21	$191.21	$191.21	$191.21	$191.21
2006	$197.54	$197.54	$197.54	$197.54	$197.54
2007	$212.72	$213.22	$212.72	$214.37	$213.22
2008	$234.38	$234.38	$234.38	$235.79	$234.38
2009	$252.73	$255.15	$252.73	$252.73	$255.15
2010	$264.78	$275.98	$279.01	$282.70	$272.37
2011	$284.32	$300.25	$305.83	$305.86	$303.98
2012	$276.31	$304.33	$294.14	$310.41	$310.27
2013	$274.37	$302.04	$291.69	$311.61	$313.71
2014	$276.27	$313.45	$291.16	$313.25	$315.25
2015	$278.90	$312.78	$291.17	$311.35	$314.25
2016	$284.12	$318.37	$294.28	$313.36	$316.96
2017	$279.15	$311.83	$288.94	$307.73	$313.15
2018	$287.92	$322.37	$297.54	$317.45	$324.05
2019	$282.02	$316.36	$290.57	$311.08	$318.41
2020	$289.16	$336.87	$295.88	$311.43	$318.08
2021	$284.30	$328.81	$288.08	$304.97	$312.43
2022	$279.07	$320.59	$282.78	$298.23	$306.42
2023	$273.53	$312.27	$279.54	$291.31	$300.12
2024	$267.76	$303.89	$270.29	$284.23	$293.58
2025	$261.81	$295.48	$264.30	$277.05	$286.86
Total	$5,706.62	$6,241.42	$5,868.04	$6,117.93	$6,185.64
Savings from Base		($534.80)	($161.42)	($411.31)	($479.02)

Source: AECI, 2005d.

In summary, based on a search in the power supply marketplace for a suitable supply of energy, and analysis of related transmission issues, AECI concluded that negotiating an acceptable power purchase agreement to meet future energy needs does not appear to be a viable option (AECI, 2004d).

2.2.2 Participation in Another Company's Project

AECI considered participation in other units including one proposed by Kansas City Power and Light (KCP&L), a subsidiary of Great Plains Energy, referred to as Iatan 2, and Peabody Coal's Prairie State plant in Illinois. Participation in these units was thoroughly evaluated by AECI and considered by its management. Peabody Energy offered joint ownership of up to 500 MW of the Prairie State plant. AECI would own and finance its share of the project and would also provide operations expertise for the project. AECI would be responsible for all transmission requirements to get power to the AECI area. The cost of the Peabody option was compared with the self-build option through 2025 in terms of present value through 2025. The Peabody cost was $100 million higher than that of the self-build option. After the Request for Proposal (RFP) process had closed, AECI became aware of the potential to participate in a project being constructed by KCP&L. KCP&L was considering a second unit (800 MW) at its Iatan plant AECI could potentially buy up to 50% of the plant. Analysis showed that this option could potentially provide a savings over a self build option. However, the future of the project was uncertain. KCP&L has partners in the first unit at Iatan which were also being approached. The regulators in Missouri were yet to rule on issues that KCP&L stated were critical to the project going forward. Also, the smaller capacity available meant that a small future coal addition would be necessary to achieve any savings. The ability to acquire 250 MW or so of coal generation in the 2013 time frame was uncertain. Based on their determination that the self-build option provided significant advantages over either of the participation options regarding the control and flexibility in decisions about the ultimate completion of the project, future dispatch requirements and operational flexibility, and compliance with future environmental regulations, AECI management rejected participation in these projects (AECI, 2005a). AECI management also determined that the self-build option offered better security for future energy prices and availability.

2.2.3 Renewable Non-Combustible Energy Sources

2.2.3.1 Current Role of Renewable Energy in U.S.

The renewable, non-combustible energy resources evaluated in this section are wind, hydroelectric, solar, and geothermal energy. All renewable energy sources, including non-combustible and combustible, accounted for approximately nine percent of the net electricity generated in the U.S. in 2005 (EIA, 2006b). Figure 2-4 shows the distribution of renewables within that nine percent.

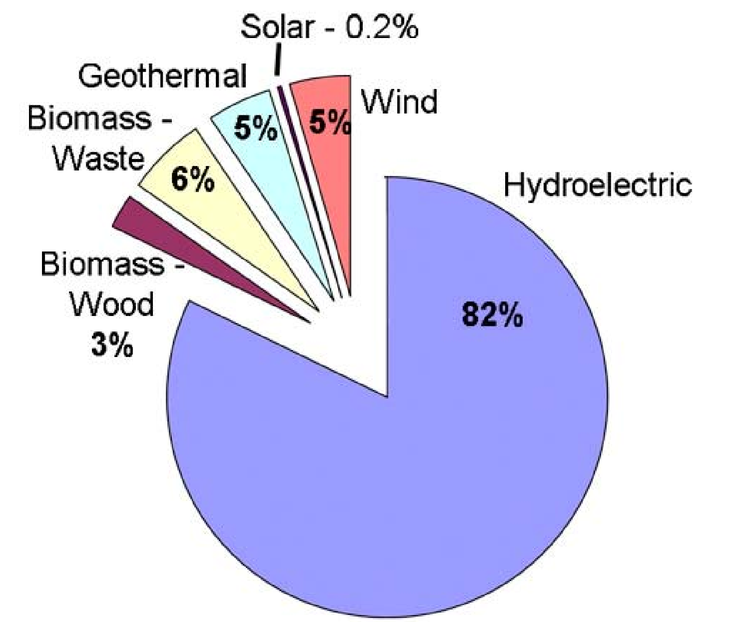

Figure 2-4. Net Renewable Electricity Generation US 2005, Electric Power Sector Electricity-Only Plants

Source: EIA, 2006b

The electric power cost projections for these technologies (1997 dollars) are shown in Table 2-2, except that hydroelectricity is not included.[7] For comparison, the power generation cost for conventional technology (1997 dollars) is about 4 to 6 cents per kWh, to the nearest cent.[8] Yellow highlight on the table indicates those technologies for which power generation costs are within the range of costs (actual or projected) for conventional technology (assuming the costs of conventional technology track the Consumer Price Index). Green highlight indicates technologies that are lower in cost than conventional technologies.

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[7] The total cost of hydroelectric power is highly variable. See discussion of the hydroelectric option later in this chapter.

[8] From DOE, 2006e. Cost information is from the graph in the reference document, which is reproduced as Figure 2-7 in this document. The Figure 2-7 is in 2001 dollars; a conversion factor of 0.91 was used to convert to 1997 dollars (Sahr, 2006).

Table 2-2. Levelized Cost of Energy (COE) from Renewable Sources.

		Levelized COE (constant 1997 cents/kWh)				
Technology	Configuration	1997	2000	2010	2020	2030
Dispatchable Technologies						
Biomass	Direct-Fired	8.7	7.5	7.0	5.8	5.8
	Gasification-Based	7.3	6.7	6.1	5.4	5.0
Geothermal	Hydrothermal Flash	3.3	3.0	2.4	2.1	2.0
	Hydrothermal Binary	3.9	3.6	2.9	2.7	2.5
	Hot Dry Rock	10.9	10.1	8.3	6.5	5.3
Solar Thermal	Power Tower	--	13.6*	5.2	4.2	4.2
	Parabolic Trough	17.3	11.8	7.6	7.2	6.8
	Dish Engine -- Hybrid	--	17.9	6.1	5.5	5.2
Intermittent Technologies						
Photovoltaics	Utility-Scale Flat-Plate Thin Film	51.7	29.0	8.1	6.2	5.0
	Concentrators	49.1	24.4	9.4	6.5	5.3
	Utility-Owned Residential (Neighborhood)	37.0	29.7	17.0	10.2	6.2
Solar Thermal	Dish Engine (solar-only configuration)	134.3	26.8	7.2	6.4	5.9
Wind	Advanced Horizontal Axis Turbines					
	- Class 4 wind regime	6.4	4.3	3.1	2.9	2.8
	- Class 6 wind regime	5.0	3.4	2.5	2.4	2.3

* COE is only for the solar portion of the year 2000 hybrid plant configuration.

Source: DOE, 2006a

Of the dispatchable technologies (those that can be provided on demand including biomass, geothermal, and certain types of solar thermal), in 2000 only hydrothermal flash energy was less costly to produce than conventional energy, and only hydrothermal binary was within the range. Of the intermittent technologies (photovoltaics, some solar thermal, and wind) Class 4 wind was within the cost range of conventional technologies, and Class 6 wind was less costly. As shown in the table, the DOE expects the cost of renewable sources to continue to decline and become increasingly competitive with conventional sources.

2.2.3.2 AECI and Renewable Energy

AECI has offered renewable energy to its members since 2003. Since January 1, 2004, Iowa law has required utilities to offer an alternate energy purchase program (Iowa Code § 476.47). While Missouri and Oklahoma do not have similar requirements, AECI's board of directors approved offering renewable energy to all member systems. AECI has offered both wind and biomass energy (AECI, 2006b).

2.2.3.3 Wind

2.2.3.3.1 Wind Energy in the U.S.

Wind energy (Figure 2-5) has grown rapidly in the U.S. in the past few years. In the summer of 2006, U.S. wind energy installations exceeded 10,000 MW in generating capacity, and produced enough electricity on a typical day to power the equivalent of over 2.5 million homes. In 2006 in the U.S., the industry will install 3,000 MW, more than the total capacity operating in 2000. The first U.S. installation was in 1981 (AWEA, 2006b). The U.S. now ranks 3rd in the world for installed wind power capacity, just behind Spain, but with about half of Germany's capacity (AWEA, 2006c). The U.S. growth is driven by the renewal of the production tax credit (PTC)[9], a federal incentive extended in the Energy Policy Act of 2005 (EPAct2005); by public demand for wind power; and by concerns over fuel price volatility and supply (AWEA, 2006a).

Figure 2-5. Modern Wind Farm

Source: AECI, 2006c

About half the current capacity for wind installations in the U.S. is in California and Texas, with Texas slightly ahead. As of August 4, 2006, Iowa had 836 MW of installed capacity, Kansas had 264 MW, and Missouri had none (AWEA, 2006e).

[9] The current value of the tax credit is 1.9 cents/kilowatt-hour of electricity produced (AWEA, 2006. The 2005 renewal of the credit was the first time it was renewed before it expired (AWEA, 2006d).

2.2.3.3.2 Wind Energy Basics

As a renewable resource, wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from Class 1 (lowest) to Class 7 (highest). The cost of energy from wind varies greatly with wind speed: the energy that can be tapped from the wind is proportional to the cube of the wind speed. For example, a site with average 16 mph winds (Class 4) will generate 50 percent more electricity than the same site with 14 mph winds (Class 3) (AWEA, 2006i). In general, at 50 meters, wind power Class 4 or higher can be useful for generating wind power with large turbines. Class 4 and above are considered good resources. Class 3 is considered fair, with some potential for utility-scale generation (AWEA, 2006g).

2.2.3.3.3 Available Wind Energy in AECI's Service Area

Of the three states included in AECI's service area, wind energy maps validated by the National Renewable Energy Laboratory (NREL) are currently available only for Missouri. The validated map for Missouri wind power at 50 meters is shown in Figure 2-6. As shown, the majority of the state does not have utility-scale wind resources; the highest ratings in the state are Class 3, and these are limited to a few areas in far northwest Missouri where AECI is already participating in wind projects (see *Section 2.2.3.3.4, Wind Energy Projects in Missouri*). Maps are available on-line for Iowa and Oklahoma, but they have not been validated and are copyright protected (AWEA, 2006g). Based on available information, the small part of southeast Iowa within AECI's service area and most of the Oklahoma service area appear to have wind resources similar to their respective adjacent parts of Missouri. The far western part of the Oklahoma service area appears to have some Class 3 resources.

2.2.3.3.4 Wind Energy Projects in Missouri

While Missouri currently is not producing energy from wind at the utility scale (generally projects that can produce greater than 25 MW), one project is under construction and another two are planned. The Wind Capital Group and John Deere Wind Energy are currently constructing a 50 MW facility, the Bluegrass Ridge Project; and are planning another two 50 MW facilities, the Cow Branch Wind Energy Project (AWEA, 2006f), the other is near Conception in Nodaway County.

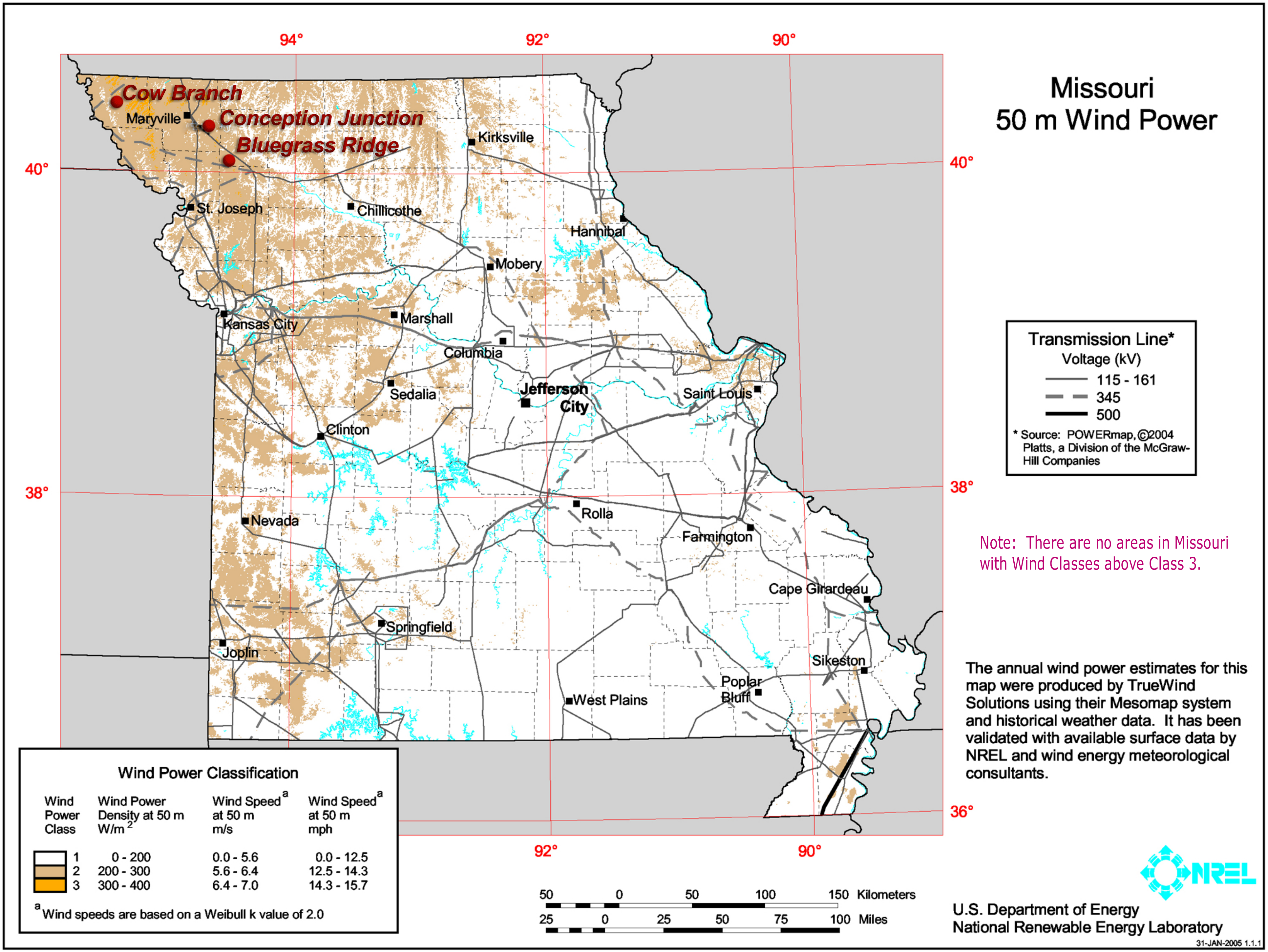

Figure 2-6 NREL Wind Map for Missouri with Wind Projects Added

Approximate locations of these facilities have been added to the Missouri wind resource map, Figure 2-6. AECI has partnered in these projects and will purchase all the energy from these three facilities (AECI, 2006b). Construction on the Bluegrass Ridge project began in summer 2006; it is expected to be operational by the end of 2006. Construction on the Cow Branch and Conception projects will begin in early 2007 with completion expected by late 2007 (AECI, 2006c).

2.2.3.3.5 Advantages and Disadvantages of Wind Energy

Wind is a clean and renewable energy source that does not pollute the air or produce greenhouse gases (GHGs) or atmospheric emissions that can cause acid rain or visibility reduction. According to the DOE (2006d) a report from the Utility Wind Integration Group (UWIG) found no issues with integrating wind power into electricity grids, provided the wind energy projects are designed and operated properly. A study from DOE's NREL examined the economic impacts of new wind, coal, and natural gas power projects in Arizona, Colorado, and Michigan, and found that wind power projects provided the greatest economic benefit to each state.

Although wind power projects have relatively little impact on the environment compared to conventional power plants, there is some concern over the noise produced by the rotor blades and aesthetic (visual) impacts; furthermore, birds and bats have been killed by flying into the rotors (DOE, 2006b). Concern about bird collisions first arose when it was found that a large number of raptors were colliding with wind turbines and associated transmission lines at two specific California wind farms (Kingley and Whittam, 2005). According to Kingsley and Whittam, who conducted a comprehensive world-wide literature search, appropriate site selection is key in minimizing bird fatalities. At most locations bird fatalities are low. The U.S. Fish and Wildlife Service (USFWS) has developed voluntary guidance “intended to assist the wind energy industry in avoiding or minimizing impacts to wildlife and their habitats” (USFWS, 2003). The guidance, however, does not rule out the possibility of the death of a migratory bird or raptor being considered a violation of the Migratory Bird Treaty Act (MBTA), which is administered by USFWS.[10] As the guidance states, the MBTA “is a strict liability statute wherein proof of intent is not an element of a taking violation.” “Take” can

[10] 16 U.S.C. 703-712. A 1972 amendment to the Migratory Bird Treaty Act resulted in inclusion of Bald Eagles and other birds of prey in the definition of migratory bird.

mean an incidental kill. The MBTA has no provision for allowing unauthorized takes.

Turbines in wind farms have been demonstrated to have the capability to adversely impact the ability of radar to detect and track aerial objects. Radar systems that might be affected include those at military installations, the National Weather Service, and the Federal Aviation Administration (FAA) Air Traffic Control. Current effective mitigation measures are limited to avoiding placement of turbines in radar lines of sight by distance, terrain masking, or terrain relief on a case-by-case basis. The Department of Defense (DOD) has initiated efforts to develop additional mitigation approaches. (DOD, 2006).

According to the American Wind Energy Association (AWEA), noise was an issue with some early wind turbine designs, but it has been largely eliminated as a problem through improved engineering and appropriate use of setbacks from nearby residences. AWEA reports that a wind turbine 250 meters from a residence is no noisier than a kitchen refrigerator (AWEA, 2006h).

Although wind farms have large acreage requirements, except for the space occupied by the support structures, the land can still be used for farming, including crops.

According to the DOE, as shown in Table 2-2 above, the current cost of wind energy from Class 4 and higher wind regimes can be competitive with energy from conventional sources. But wind is an intermittent source, and if the cost of firming, a requirement for base load, (having an alternate energy source when the wind is not blowing) is considered, wind is not yet cost-competitive. The cost of wind energy is still high enough compared to other available energy sources that tax credits are needed to implement programs. It is for this reason that the Energy Policy Act of 2005 authorized $2.7 billion to extend the renewable electricity production tax credit.

2.2.3.3.6 Summary of Reasons for Elimination of Wind as the Energy Source for this Project

While AECI has committed to purchase all the wind energy from the only wind utility-scale projects under construction or planned in Missouri, wind was eliminated as a potential energy source for the needed baseload energy for the following reasons:

- Wind, being an intermittent energy source, is not suitable for baseload needs.

- AECI's service area does not have adequate resources to consider wind for this project.

2.2.3.4 Solar

Two methods are used to convert solar energy to electricity:

- Photovoltaics, which are semiconductors that convert solar energy directly to electricity.
- Thermal systems, which use concentrated solar rays to produce heat for conventional steam technologies.

2.2.3.4.1 Photovoltaics

Figure 2-7. Photovoltaic Flat Plate Collector.

Source: National Renewable Energy Laboratory, Photographic Information Exchange

For generation of electricity, photovoltaic cells are typically arranged into flat arrays (flat plate collectors) and placed at a fixed angle to receive maximum sun at a given latitude (Figure 2-7). Because of their simplicity, flat-plate collectors are often used for residential and commercial building applications. They can use both direct rays from the sun and reflected rays from clouds or off the ground (DOE, 2006f). Photovoltaic arrays are economically used at remote locations for lighting, pumping water, etc., but are not cost-competitive when conventional electric sources are available. The kWh cost for a large installation in an average sunny climate is about 22 to 40 cents (costs are higher for smaller installations and cloudy climates) (Solarbuzz, 2006). For comparison, the average U.S. residential per kWh charge was about 9 cents in 2004 (EIA, 2005a) and rural Missouri rates were even lower.

Figure 2-8 shows solar resources for a flat plate collector. Missouri has a good useful resource throughout the state for very small-scale applications, as do the parts of Iowa and Oklahoma within AECI's service area (DOE, 2006f).

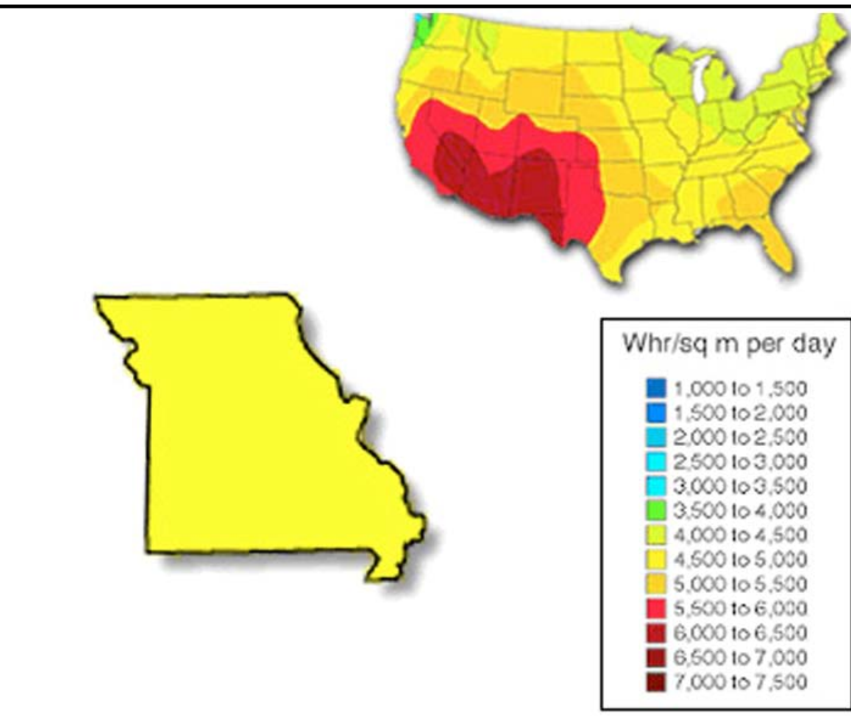

Figure 2-8. Solar Resources for Flat Plate Collector

Source: DOE, 2006f

2.2.3.4.2 Concentrating Solar Power (CSP)

There are currently three configurations of this technology. In all of these technologies, solar rays are concentrated using mirrors, which transfer heat either to a heat transfer fluid (oil or salt) or directly to water creating steam. The heat transfer fluid is then used to generate steam that powers turbines thus generating electricity in a conventional steam generator. Designs can incorporate thermal storage—setting aside the heat transfer fluid in its hot phase—allowing for electricity generation several hours into the evening. Some designs are "hybrids," meaning they use fossil fuel to supplement the solar output during periods of low solar radiation. Typically a natural gas-fired heat or a gas steam boiler/reheater is used; CSP also can be integrated with existing coal-fired plants.

The southwestern U.S. potentially offers the best development opportunity for CSP technologies in the world (Figure 2-9), and that is where existing U.S. CSP facilities are located. There is also a strong correlation between electric power demand and the solar resource due largely to air conditioning loads in the region (2006e). Missouri, however, does not have the solar resources for large-scale CSP systems (DOE, 2006f).

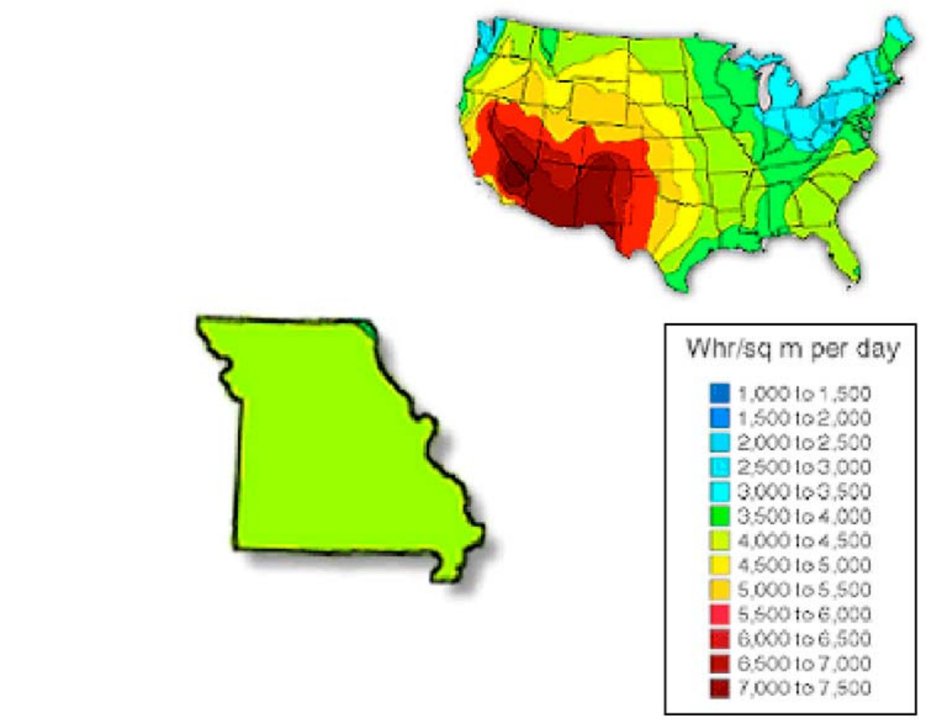

Figure 2-9. Solar Resources for Concentrating Collector

Source: DOE, 2006f

Even in the southwest solar power is not yet cost competitive with conventional power sources, as shown in Table 2-2. The data in Table 2-2 is based upon technology demonstrations in 2000 – 2001 in the US and Spain. While technological advances are occurring, they are not currently on pace to meet the cost expectations in this reference. Also, for economy of scale, several square miles would be needed for the facility.

2.2.3.4.3 Summary of Reasons for Elimination of Solar as the Energy Source for this Project

Photovoltaic power generation was eliminated as a potential energy source for the needed baseload energy for the following reasons:

- It is an intermittent energy source and is not suitable for baseload needs.

- The cost is several times higher than other available energy sources.

CSP was eliminated as a potential energy source for the needed baseload energy for the following reasons:

- While CSP systems are effective in supplementing conventional power plants in the southwest, suitable solar resources are not available in AECI's service area for large-scale power generation.

- The cost of CSP is not competitive with power from other sources.

2.2.3.5 Hydroelectric

The power source for the hydroelectric turbine is moving water. In some cases, small hydroelectric facilities can operate without damming a stream, but to produce utility-scale energy a dam is needed (Figure 2-10).

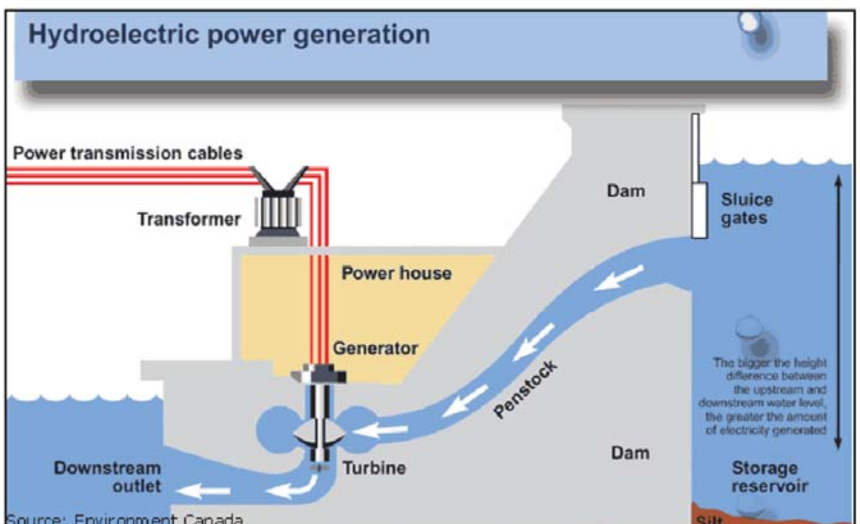

Figure 2-10. Hydroelectric Power Generation

2.2.3.5.1 Hydroelectric Energy in the U.S.

In the U.S. in 2005 conventional hydroelectricity accounted for six percent of all net electricity generated and 74 percent of renewable energy (EIA, 2006b). Fifty years ago, hydroelectricity represented a very large percent of energy generated in the U.S. (Figure 2-2). As shown in Figure 2-2, production of electricity from hydropower has been fairly flat since the mid-1970s. The U.S. ranked fourth in the world in hydroelectric power production in 2004, behind Canada, China, and Brazil, and accounted for about 10 percent of the world's hydroelectric power production.[11] In 1980, the U.S. ranked first and accounted for 17 percent of world production (EIA, 2006d).

Just over half the hydroelectric power produced in the U.S. comes from facilities owned by the U.S .Government, and nearly all of that comes under the jurisdiction of three agencies: the U.S. Army Corps of Engineers (USACE) (largest U.S. hydropower producer), the Bureau of Reclamation (BOR) (second largest), and the Tennessee Valley Authority (INL, 2006a). The largest hydroelectric facility in the U.S. is the BOR's Grand Coulee, with a capacity of 6,809 MW (BOR, 2006a).

Undeveloped Hydropower Resources in the U.S.

Very few large dams, hydropower or otherwise have been built in the U.S. since around 1980 (USGS, undated). According to the USACE, "Beginning in the 1960s, an increasingly urbanized, educated society focused more on recreation, environmental preservation, and water quality than on irrigation, navigation, or flood control" (USACE, 2006d). The BOR's current vision for providing water for the west includes conservation and rehabilitation of existing facilities, not dams (BOR, 2005). Many of the environmental and cultural laws of the 1960s and early 1970s made new dam construction much more difficult and expensive. These laws include the Wilderness Act (1964), the Wild and Scenic Rivers Act (1968), the National Environmental Policy Act (NEPA) (1969), the National Historic Preservation Act (NHPA) (1966) and the Endangered Species Act (1973). The dramatic 1976 failure of the BOR's Teton Dam just as it was being filled, which resulted in 14 deaths and about $1 billion in damage brought a new recognition of the potential threat of large dams (Sylvester, undated). In addition, "most of the good spots to locate hydro plants have already been taken" (USGS, undated).

[11] China will soon surpass Canada, with several very large projects under construction.

The BOR has several dam projects that were authorized in the 1960s and have never been completed, for a number of reasons, including environmental issues, water rights issues, public opposition, cost, safety concerns, and lack of funding (for example, the Auburn Dam in California, the Narrows Dam in Colorado, the Orme Dam in Arizona, the Garrison Project in North Dakota (BOR, 2006c, 2006d, 2006e; Garrison Diversion, 2004)). The Auburn Dam in California, for example, was authorized in 1965, and was to provide a 750 MW power plant, flood control, and irrigation. Construction began in 1967, was suspended in 1977, and has not yet resumed. Proponents of the project indicate the BOR estimates the cost at $3 billion (Auburn Dam Council, undated). In the Missouri area alone, the USACE had two similar projects.[12]

A number of studies have assessed the existing undeveloped hydropower resources in the U.S. According to an Idaho National Laboratory (INL) study (Connor et al, 1998), previous studies by the DOE's Hydropower Program[13], the Federal Energy Regulatory Commission (FERC), and the USACE did not account for environmental, legal, and institutional constraints and therefore over-estimated available developable resources. The 1998 INL study estimated a total of 30,000 MW of available undeveloped resources, compared to, for example, the USACE's previous theoretical estimate of 580,000 MW. Most of the INL 1998 estimated 30,000 MW are from rivers in the northwest U.S., including Alaska. Notably, there have been two dam projects move forward: a new dam, the Animas-La Plata Project (ALP) near Durango, Colorado, and a modification of an existing dam on Lake Fort Smith in Arkansas.

In a 2003 publication, the DOE revised their U.S. hydropower estimate to 170,000 MW of undeveloped resources, but much of this would apparently be very small scale (DOE, 2003). The 2003 DOE report states that the DOE's goals for hydropower are "a 10% growth in generation at existing plants and

[12] A planned dam on the Buffalo River, which would have been the final authorized dam in the White River watershed (located along the Missouri-Arkansas border) was never constructed. After decades of controversy it was deauthorized (NPS, 1987). Construction had begun on the Corps' controversial Meramec River Dam when a non-binding referendum in 1978 indicated the majority of the affected public did not want the project. It was de-authorized in 1981 (Watkins, undated).

[13] The mission of DOE's Hydropower Program "is to conduct research and development (R&D) that will improve the technical, societal, and environmental benefits of hydropower and provide cost-competitive technologies that enable the development of new and incremental hydropower capacity, adding diversity to the nation's energy supply." The Idaho National Laboratory provides technical support to the Hydropower Program. http://hydropower.inl.gov/ (accessed September 2, 2006).

harnessing undeveloped hydropower capacity without constructing new dams."

Most recently, the DOE's Hydropower Program has explicitly acknowledged the unlikelihood of development of large hydropower projects in the U.S. today (INL, 2006a). Therefore, the Program has concluded that "hydroelectric growth is dependent upon the development of distributed generation using low power and small hydro class plants. For significant growth to occur, there will have to be a dramatic increase in the number of these plants and probably an accompanying increase in the number of plant owners" (INL, 2006a). As discussed in Section *2.1.2.2.2, Siting Alternatives*, distributed generation is not a reasonable alternative for AECI's needs.

Another potential source of additional hydropower capacity is upgrading existing facilities. The DOE notes that the National Hydropower Association estimates this could achieve more than 4,300 MW of additional power (DOE, 2003).[14] Section 1834 of the Energy Policy Act of 2005 (EPACT 2005) requires the U.S. Departments of Interior (DOI) and the Army to assess and report on, by February 2007, options to increase hydropower capacity at existing federal facilities. The assessments are required to address the impact of increased hydropower production on other competing interests including irrigation, water supply, wildlife, fish, Indian tribes, river health, navigation, recreation, fishing, and flood control.

2.2.3.5.2 Hydroelectric Resources in AECI's Service Area

Existing Resources

There are several large reservoirs in and near Missouri that are, or could potentially be used to generate hydroelectric power (Figure 2-11). These reservoirs are summarized in Table 2-3.[15] Reservoirs that are currently used to generate hydroelectricity are highlighted in pink in Figure 2-11, and the hydropower capacity is listed in Table 2-3. As shown in the table, there are

[14] The National Hydropower Association's Web Site states that DOE estimates an additional 17,000 MW could be achieved by adding hydropower to dams where it is environmentally and economically feasible. Neither source provides specific references. http://www.hydro.org/home/ (accessed September 3, 2006).

[15] All the reservoirs in Table 2-3 are shown in Figure 2-11 except Rathbun, which is located in Iowa, north of the mapped area.

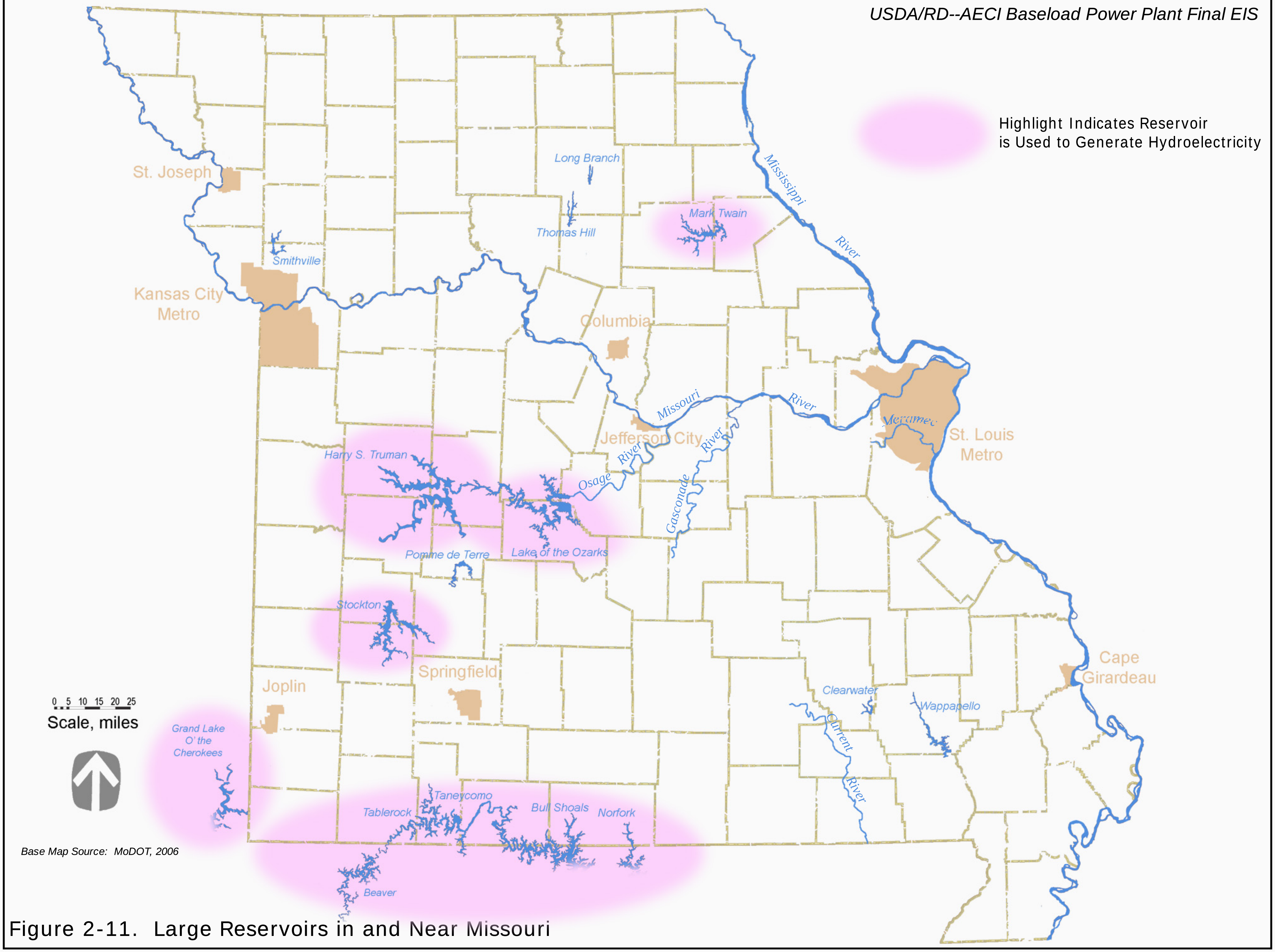

Figure 2-11. Large Reservoirs in and Near Missouri

Table 2-3. Large Reservoirs in and Near Missouri

Name	Reservoir Owner/Operator	Hydropower Owner/Operator	Year Dam Completed	Hydropower Capacity, MW	Used for Water Supply?
Beaver Lake	US Government/ Department of Defense, Army Corps of Engineers, Little Rock District	US Government/ Department of Energy, Southwestern Power Administration	1966	112	Yes. Primary source of water for most of Northwest Arkansas.
Table Rock Lake	US Government/ Department of Defense, Army Corps of Engineers, Little Rock District		1958	200	Yes.
Taneycomo	Empire District Electric Company	Empire District Electric Company	1913	16	Not known. Recreational lake, privately owned.
Bull Shoals Lake	US Government/ Department of Defense, Army Corps of Engineers, Little Rock District	US Government/ Department of Energy, Southwestern Power Administration	1952	391	Yes.
Norfork Lake	US Government/ Department of Defense, Army Corps of Engineers, Little Rock District		1944	70	Yes.
Clearwater Lake	US Government/ Department of Defense, Army Corps of Engineers, Little Rock District	N/A	1958	None	No.
Lake Wappapello	US Government/ Department of Defense, Army Corps of Engineers, St. Louis District	US Government/ Department of Defense, Army Corps of Engineers, St. Louis District	1941	0.1 (for facility operation only)	No.
Mark Twain Lake	US Government/ Department of Defense, Army Corps of Engineers, St. Louis District	US Government/ Department of Energy, Southwestern Power Administration	1984	58	Yes. Clarence Cannon Wholesale Water Commission distributes about 2.5 million gallons daily to a large area around the lake.

Table 2-3. Large Reservoirs in and Near Missouri

Name	Reservoir Owner/Operator	Hydropower Owner/Operator	Year Dam Completed	Hydropower Capacity, MW	Used for Water Supply?
Grand Lake O' the Cherokees	State of Oklahoma Grand River Dam Authority	State of Oklahoma Grand River Dam Authority	1940	125	Unknown. Would be allowed by the enabling legislation, but sales would be limited to Oklahoma.
Lake of the Ozarks (Bagnell Dam)	Ameren	Ameren	1931	226	Not known. Recreational lake, privately owned.
Stockton Lake	US Government/ Department of Defense, Army Corps of Engineers, Kansas City District	US Government/ Department of Energy, Southwestern Power Administration	1968	45	Yes[1]
Harry S. Truman Reservoir			1977	160	Yes[1] In 1994, 1,000 acre-ft was re-allocated from flood control to water supply.
Pomme de Terre Lake		N/A	1960	None	No
Smithville Lake		N/A	1976	None	Yes[1]
Long Branch Lake		N/A	1976	None	Yes[1]
Rathbun Lake		N/A	1967	None	Yes[1]
Thomas Hill Reservoir	AECI	N/A	1966	None	No

[1] Users of water supply in the Kansas City District Corps of Engineers are state agencies, municipalities, and rural water districts (USACE, 2003).

Sources: UADA, undated.
USACE, undated.
Ameren, 2006.
USACE, 2005a.
http://www.swl.usace.army.mil
Bull Shoals hydro capacity: http://arkansasflyfishing.4t.com/about.html
Norfork hydro capacity: http://www.geocities.com/antares573/norfork/norfork_dam.html
Table Rock hydro capacity: http://www.visittablerocklake.com/lake/lakemain.html
Clearwater Lake year built: http://www.cityofpiedmont.com/dam.html
http://www.cannondam.com/lake/facts.shtml
Mark Twain Lake information: http://mdc.mo.gov/fish/watershed/salt/watqual/350wqtxt.htm
Grand Lake O' the Cherokees information: http://www.grda.com

10 facilities in the area with a total of 1,403 MW of hydropower capacity. Two of these (Taneycomo and Bagnell, 242 MW total) are privately owned, one is owned by the State of Oklahoma (Grand River, 125 MW), and the remaining seven are owned by the U.S. government and operated by the USACE (1,036 MW). Hydropower at all the USACE dams is administered by the Southwest Power Administration (SWPA), which is part of the U.S. Department of Energy (DOE), and was established by the Flood Control Act of 1944. The agency is responsible for marketing the hydroelectric power produced at 24 USACE multipurpose dams. By law, the power and associated energy are marketed to publicly held entities such as rural electric cooperatives and municipal utilities (SWPA, 2006). AECI annually purchases 478 MW of peaking power capacity from SWPA, about 573,000 MWh of energy.

The DOE's 1998 study of available hydropower resources concluded that there are approximately 104 MW of undeveloped capacity at Missouri sites that currently have hydropower facilities (Connor, 1998). The USACE's current required assessment of existing facilities, due to be reported in 2007, should have updated values. While no readily available information was found for the small 58-MW facility at Mark Twain Reservoir, available information for the other USACE facilities in and near Missouri suggests that adding hydropower capacity would not be productive until and unless more of the existing capacity can be used. For example, in 2003, the most recent year for which data were found, the Kansas City District's Truman and Stockton facilities, with a total capacity of 205 MW, operated at average capacity factors of 3.5%. Releases are severely restricted by downstream channel capacities and a signed agreement among the USACE, SWPA, and the State of Missouri (USACE, 2003). The White River hydro facilities, located along the Missouri-Arkansas border, with about 1,000 MW capacity, operated at an average capacity factor of about 19 percent in 2004 (USACE, 2005b). There is no unallocated water in the White River system, and legal mandates exceed available supplies (USACE, 2004a).

Existing Large Reservoirs not Currently Used for Hydropower

Seven of the large reservoirs in and near Missouri (Figure 2-11) currently do not have utility-scale hydropower facilities.[16] All of these except AECI's Thomas Hill Reservoir are USACE facilities. The USACE's reservoir usages are set by the legislation that authorized the project. It would require a change in

[16] As noted in Table 2-3, Lake Wappapello has a small plant.

the law to authorize installing hydropower facilities at these reservoirs. Installing hydropower facilities at Thomas Hill is not an option as there is no surplus water storage at this facility, as discussed later in this document.

The DOE estimated that there is about 181 MW of undeveloped capacity at dammed sites without existing hydropower facilities (Connor, 1998). The majority of that is probably represented by the reservoirs discussed above.

Undeveloped Sites

The DOE (Connor, 1998) estimated that there is about 38 MW of hydropower capacity at undeveloped sites in Missouri. This is insufficient for AECI's need for 660 MW.

2.2.3.5.3 Advantages and Disadvantages of Hydroelectricity

Once the facilities are constructed, hydroelectricity is inexpensive to produce, requires no fuel, and creates negligible emissions or waste. It is renewable and the technology is developed.

The construction of large hydropower facilities has large impacts. Every reservoir shown on Figure 2-11 represents miles of river and thousands of acres—more often tens of thousands, and in some cases, hundreds of thousands—of wetland, floodplain, woodland, farmland, and residences that have been replaced by water. After construction, downstream aquatic habitat can be adversely impacted by abrupt flow changes, low flows, temperature changes, and low dissolved oxygen (DO) (MDC, 2005).

The total cost of hydropower can vary greatly. Operating costs are low, compared with other alternatives (EIA, 2005a):

- Hydro (conventional and pumped storage) $8.69/MWh
- Nuclear $18.26/MWh
- Fossil steam $23.85/MWh
- Gas turbine and small scale (gas turbine, internal combustion, photovoltaic, wind) $50.10/MWh.

But capital costs vary greatly and can be very high. There is a large range in size, which affects cost. The DOE (INL, 2006b) has estimated capital costs for U.S. installations at $1.7 to $2.3 million per MW, but the actual range may be much greater. Site conditions can vary greatly, and siting options are limited (the facility has to be on a river).

Table 2-4 summarizes available information for the capital cost of hydropower facilities within and near AECI's service area. As shown, costs are highly variable and sometimes very high. The largest facilities have costs within the INL range, but some are much higher. For comparison, the 2005 estimated capital cost of AECI's proposed 660 MW net coal-fired plant at Norborne was $1 billion (AECI, 2005a), which is $1.5 million/MW. This is the cost basis used throughout this document. Costs increase over time, however, and the current estimate, based on bids, is about $1.4 billion or $2.1 million/MW.

Table 2-4 Capital Costs of Hydropower Facilities

Reservoir	Year Completed	Hydropower Capacity, MW	Original Cost, $million	Cost 2006 $million	$million/MW, 2006	Reference for Original Cost
Taneycomo	1913	16	2.3	47	2.9	Rockaway Beach Chamber of Commerce, 2006
Lake of the Ozarks	1931	226	30	402	1.8	Ozark Digital Data, undated
Grand Lake O' the Cherokees	1940	125	27	392	3.1	Grand Lakes Web, 2006
Norfork	1944	70	28.6*	331	4.7	USACE, 2006a
Bull Shoals	1952	391	86	673	1.7	USACE, 2006c
Table Rock	1958-1961	200	65.4	450	2.2	Table Rock Lake Chamber of Commerce, 2006
Beaver	1966	112	46.2	290	2.6	USACE, 2006b
Truman	1977	160	500	1,700	10.6	Truman InfoGuide, 2006
Mark Twain	1984	58	304	603	10.3	Hannibal Courier-Post, 2006

2006 costs from CPI Inflation Calculator (BLS, 2006)
Year completed and hydropower capacity—see Table 2-3 sources.
*Reference explicitly stated this was the cost of dam and powerhouse.

2.2.3.5.4 Summary of Reasons for Elimination of Hydroelectric as the Energy Source for this Project

Hydroelectric power was eliminated as a potential energy source for the needed baseload energy for the following reasons:

- Hydroelectric power, at least in AECI's service area, is used for peaking and is not suitable as a baseload resource. The constant flow required is not available at any existing facility, and would not be available at the few locations that are feasible for development.

- Even as a peaking resource, there are inadequate developable resources within and near AECI's service area.

- Based on the history of dam building over the last 40 years in the U.S., there are large risks in construction time and capital costs.

2.2.3.6 Geothermal

Geothermal energy is contained in underground reservoirs of steam, hot water, and hot dry rocks. Only those resources hot enough to produce steam to drive a turbine can be used to generate electricity (EIA, 2006l). Where these resources are available, electricity can be produced at prices competitive with conventional sources (Table 2-2). In the U.S., all these high temperature geothermal resources are located in the western states. Missouri has no geothermal resources; the nearest high-temperature resources are in New Mexico.

Geothermal energy was eliminated as a potential energy source for the needed baseload energy because there are no resources available.

2.2.4 Renewable Combustible Energy Sources: Biomass

Combustible fuels can be categorized as fossil (non-renewable) or biomass (renewable). Biomass energy is derived from three distinct energy sources: wood, waste, and alcohol fuels (EIA, 2005b).

2.2.4.1 Energy from Wood

Energy derived from wood accounted for about 80 percent of the biomass energy consumed in the U.S. in 2004, but most of this energy was not generated by the electric power sector. Wood energy is derived both from direct use of harvested wood as a fuel and from wood waste streams. The largest source of energy from wood is pulping liquor or “black liquor,” a waste product from processes of the pulp, paper and paperboard industry. Only seven percent of the wood energy consumed in 2004 was produced by the electric power sector for electricity (EIA, 2005b). As shown in Figure 2-4, energy derived from wood accounts for about 3 percent of the renewable energy generated by the electric power sector. As shown in Table 2-2, the cost of direct-fired biomass is estimated at 7.5 cents per kWh (2000), projected to 7.0 cents per kWh in 2010 (in 1997 dollars). This is well above the comparable cost of conventional power generation (about 4 to 6 cents per kWh).

2.2.4.2 Energy from Waste

Energy from waste is the second-largest source of biomass energy, accounting for about 20 percent of biomass energy consumed in 2004, and about 6 percent of the renewable energy generated by the electric power sector. Most of the energy from waste (79 percent) is from municipal solid waste and landfill gas, and about three quarters of that amount was produced by the electric power sector (EIA, 2005b).

2.2.4.2.1 Municipal Solid Waste (MSW)

Conventional direct combustion is presently the most common technology used in the U.S. for biomass solids waste-to-energy (WTE) power generation. Biomass power boilers are typically in the 20-50 MW range. The small capacity plants tend to be lower in efficiency because of economic trade-offs; efficiency-enhancing equipment cannot pay for itself in small plants. Although techniques exist to push biomass steam generation efficiency over 40 percent, actual plant efficiencies are in the low 20 percent range. Direct fired biomass power plants generally require more involved technologies to reduce air emissions and more intensive material handling systems than conventional coal fired power plants. These additional facilities lead to higher biomass power plant capital and operating costs when compared to conventional coal fire plants. Unless a metropolitan region is faced with high

MSW disposal expenses, a WTE biomass facility is generally not considered cost effective for power production. WTE facilities are best suited for high population metropolitan regions where regional landfill development is restrictive (AECI, 2004c). As noted in Table 2-2, the cost of producing direct-fired biomass energy is well above the cost of conventional power generation techniques.

2.2.4.2.2 Landfill Gas

Landfill gas is created when organic waste in a landfill naturally decomposes. This gas consists of about 50 percent methane, the primary component of natural gas, about 50 percent carbon dioxide (CO_2), and a small amount of non-methane organic compounds. Instead of allowing landfill gas to escape into the air, it can be captured and used as an energy source through combustion to produce electricity. To collect landfill gas, wells are drilled into the landfill, a well field collection system is installed, and the gas is piped to a clean-up system. Reciprocating engines are generally used for landfill gas projects with total generation ranging from 0.1 to 5 MW and gas turbines are generally used at large municipal solid waste landfills with higher landfill gas capacities. The largest landfill gas project identified by AECI was a 50 MW combined cycle project by the Los Angeles County, California, Sanitation District. Although landfill gas technology is proven, its capability is limited. Based on the U.S. Environmental Protection Agency’s (EPA) Landfill Methane Program Outreach database, landfill gas projects are typically in the 0.1 to 20 MW size range, compared to coal-fired plants in the 100-1,500 MW range. In addition, the landfill gas collection and cleanup system result in higher capital costs than a conventional simple cycle natural gas fired combustion turbine power plant (AECI, 2004c). As shown above in Table 2-2, the DOE’s estimated cost (1997 dollars) for gas-based biomass technology is 6.7 cents per kWh for the year 2000, and projected at 6.1 cents per kWh for 2010. The comparable cost of energy from a coal-fired plant is about 4 to 6 cents per kWh (Deutch and Moniz, 2006).

2.2.4.2.3 Other Waste

The other 21 percent of waste used for energy consists of agriculture byproducts/crops, sludge waste, tires, and other biomass solids, liquids and gases. About 24 percent of this energy was produced by the electric power sector; some in coal co-fired plants.

2.2.4.3 Alcohol and Biodiesel Fuels

In the U.S., biomass alcohol fuel, or ethanol, is derived almost exclusively from corn. Its principal use is as an oxygenate in gasoline (EIA, 2005b). In the U.S., biodiesel fuel is produced primarily from soybeans. These fuels may have future application as automotive fuels but they are unlikely to be used for large-scale production of electricity.

2.2.4.4 Advantages and Disadvantages of Biomass

Perhaps the greatest benefit of biomass for electric power production is that it uses waste material that might otherwise be landfilled. For example, at Central Electric Cooperative's coal-fired Chamois Plant, which AECI dispatches, biomass fuels, such as used railroad ties, shelled corn, sawdust, and walnut shells are co-fired with coal when such fuels are available. The walnut shells have proven to produce the greatest amount of heat value of the biofuels burned at the facility. Other wastes are considered when available and economical to transport, treat, and burn (AECI, 2005a).

The DOE sees the potential for biomass in electric power production primarily as part of a distributed system. In the U.S., modular systems (5 kW to 5 MW) could be hooked into existing transmission and distribution systems near the rural homes, farms, ranches, and industries likely to produce and use biopower. Examples of energy consumers that might install biopower systems include commercial hog farming operations, paper companies, and food processing plants with high energy costs and stockpiles of corn cobs or rice husks needing disposal (DOE, 2006h).

2.2.4.5 Summary of Reasons for Elimination of Biomass as the Energy Source for this Project

Production of the needed electricity from biomass was eliminated from further consideration for the following reasons:

- The cost is significantly higher than available conventional technologies.
- It is most practical and economical to use the biomass where it is generated, which means relatively small systems, much smaller than the 660 MW required.

Co-firing of biomass was also not considered further. Only certain types of coal-fired systems lend themselves to co-firing. The Chamois Plant is able to use certain wastes that are available to AECI and technically feasible and economical to burn. Restricting options in a large planned facility just to create the potential for co-firing biomass does not make economic sense when AECI already has available capacity for co-firing in an existing plant.

2.2.5 Non-Renewable Combustible Energy Sources

The non-renewable combustible energy sources for electricity generation, commonly referred to as fossil fuels, are natural gas, petroleum, and coal.

2.2.5.1 Natural Gas

2.2.5.1.1 Natural Gas Usage and Production in the U.S.

Figure 2-12 is a flow diagram for natural gas in the U.S. that shows, flowing from left to right, origins and end uses. As shown in the figure, in 2005 the U.S. produced most of the natural gas it consumed. Most of the imports were from Canada via pipeline (EIA, 2006g). Approximately 26 percent of natural gas consumption was used to generate electricity by the electric power sector (right side of figure).

In 2005, about 15 percent of the electricity produced by the electric power sector was from natural gas. Figure 2-13 shows natural gas usage for electricity generation since 1970.[17] For the years shown on the chart, natural gas usage was at a high of 24 percent in 1970, and the price was at a low of 86 cents per 1,000 cubic feet (wellhead price, constant 2005 dollars). As the real price of natural gas rose to its first peak in the early 1980, there was a corresponding drop in the percentage of natural gas as a source for electricity. There was a resurgence of interest in natural gas beginning in the early 1990s as natural gas prices fell, and many natural gas plants were planned and constructed. As recently as 2004, ninety-four percent of the new unit capacity was natural gas-fired or dual-fired (capable of burning either natural gas or petroleum) (EIA, 2005a).

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[17] The percentage for Figure 2-13 are slightly different than those shown in Figure 2-2. Figure 2-13 includes combined heat and power plants and Figure 2-2 does not. EIA does not have readily available historic data for electricity-only plants.

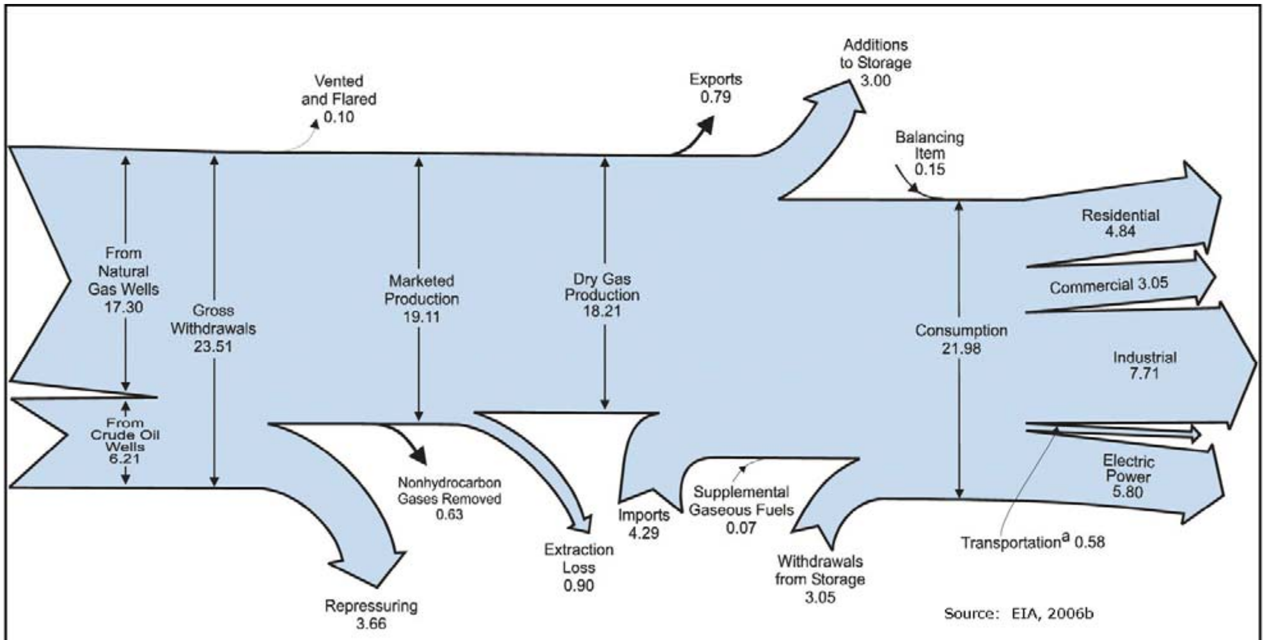


Figure 2-12. Natural Gas Flow, 2005 (Trillion cubic ft)

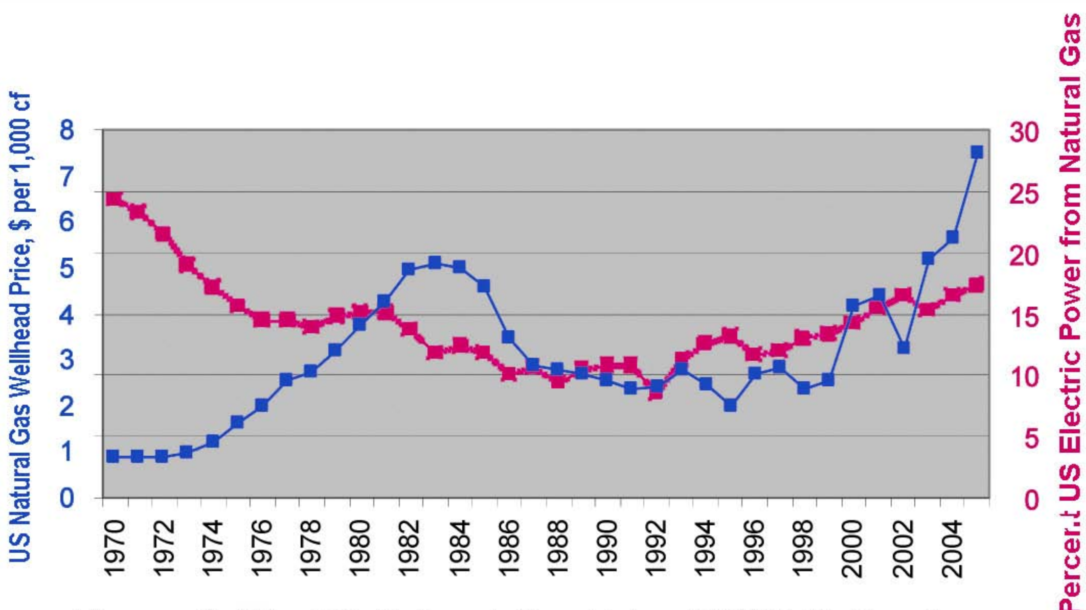


Figure 2-13. US Natural Gas Price (2005 Dollars) and Electric Power Usage from Natural Gas

In the economics of electricity generation, fuel cost plays a much greater role for natural gas than for nuclear and coal, the other two leading electric power sources (MIT, 2003). Natural gas plants, compared to coal and nuclear, have lower capital costs and the plants can be constructed in a shorter time period (Figure 2-14).

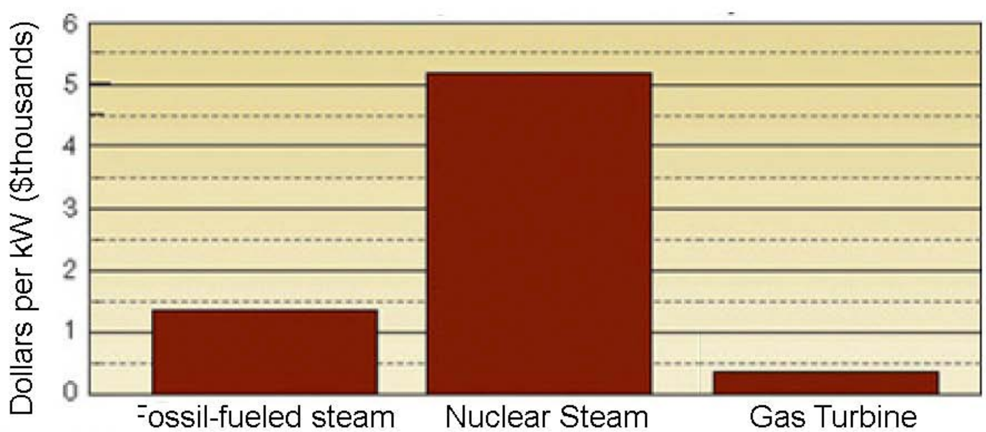


Figure 2-14. Original Plant Costs for Plants that Began Commercial Operation 1990 -1994 (1996 Dollars)

Source: INL, 2006b

While the initial investment for natural-gas fired plants is relatively smaller, operating costs can be substantially higher, depending primarily on fuel costs (Figure 2-15). As shown, in 2004 gas turbine plants were considerably more expensive to operate than either nuclear or fossil steam plants. The differential was even greater in 2005, when average natural gas prices were 38 percent higher than in 2004 (EIA, 2006i).

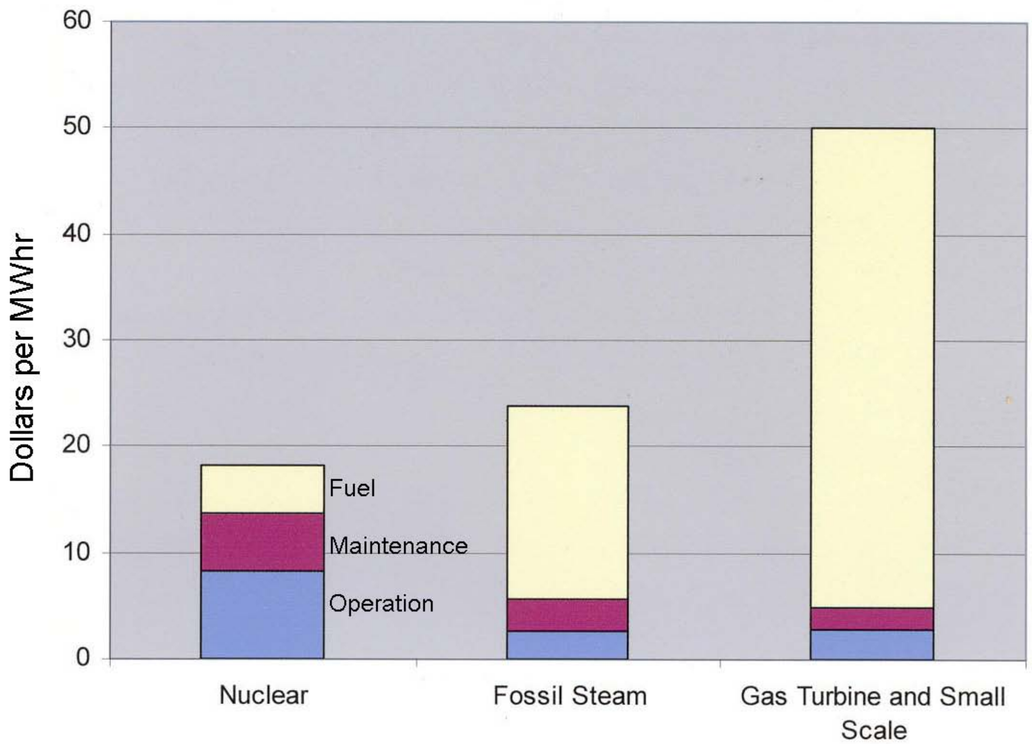


Figure 2-15. Average Operating Expenses for Major US Investor-Owned Utilities, 2004

Source: EIA, 2005a

Table 2-5 compares overall costs for several of the fossil fuel technologies AECI evaluated. As shown, while capital costs for natural gas systems are much lower than any of the coal alternatives, fuel costs and total costs are higher than all the coal options. (Fuel costs used were April 2006, the latest available.) As shown in Figure 2-13 and in Figure 2-16, the price of natural gas also fluctuates dramatically, thus adding considerable uncertainty to future electric energy generation costs for natural gas. During 2005 alone, natural gas monthly wellhead prices (dollars per 1,000 cubic ft) ranged from $5.52 in January to $10.97 in October (EIA, 2006j).

Table 2-5. Electric Power Cost Projections for Non-Renewable, Combustible Energy Resources

Technology	Cost Component (2005 dollars)			
	Capital ($/kW)	Fixed O&M ($/KWyr)	Variable/ Fuel ($/KWh)	Total Busbar Cost ($/year)
Natural Gas Combined Cycle (NGCC)	592[1]	12.4[1]	0.0291[1,2]	191,038,000[3]
Microturbines	1,856[4]	6.5[5]	0.09083[6]	575,633,000[3]
Supercritical Pulverized Coal (SCPC) Powder River Basin (PRB) Coal	1,340[7]	35.9[7]	0.00233[7]	107,101,000[3,7]
Circulating Fluidized Bed (CFB) Powder River Basin (PRB) Coal	1,474[7]	37.0[7]	0.00350[7]	121,043,000[3,7]
Integrated Gasification Combined Cycle (IGCC) Powder River Basin (PRB) Coal	1,754[7]	49.9[7]	0.00117[7]	132,328,000[3,7]

Notes:
Busbar cost is the cost at the source (does not include transmission and distribution).
Microturbines are small electric generation units usually powered by natural gas. This option is not discussed in detail because its high cost and application only to distributed generation eliminates it from consideration.

[1] DOE "Market Based Advanced Coal Powered Systems" Appendix E "H" Class Turbine, May 1999.
[2] Fuel costs based upon Energy Information Administration April 2006 Natural Gas Electric Power Price and net plant heat rate of 6,396 Btu/kWh for a "H" Class Turbine in DOE "Market Based Advanced Coal Powered Systems" Appendix E, May 1999.
[3] Capital Costs are converted to annual capital recovery cost for this comparison using an economic life of 30 years and a 7% pretax marginal rate of return.
[4] Energy Solutions Center, "Distributed Generation Application Guide" Table 4-2 for a 100 kW CHP system. Accessed at www.energysolutionscenter.org/DistGen/AppGuide/Chapters/Chap4/4-2_Microturbines.htm.
[5] Resource Dynamics Corporation, "Assessment of Distributed Generation Technology Applications", February, 2001.
[6] Fuel costs based upon Energy Information Administration April 2006 Natural Gas Electric Power Price and net plant heat rate of 13,127 Btu/kWh for a 100 kW system in Energy Solutions Center, "Distributed Generation Application Guide" Table 4-2. Accessed at www.energysolutionscenter.org/DistGen/AppGuide/Chapters/Chap4/4-2_Microturbines.htm.
[7] Sargent & Lundy, "New Coal Unit Electricity Generating Technology Evaluation", November 2005.

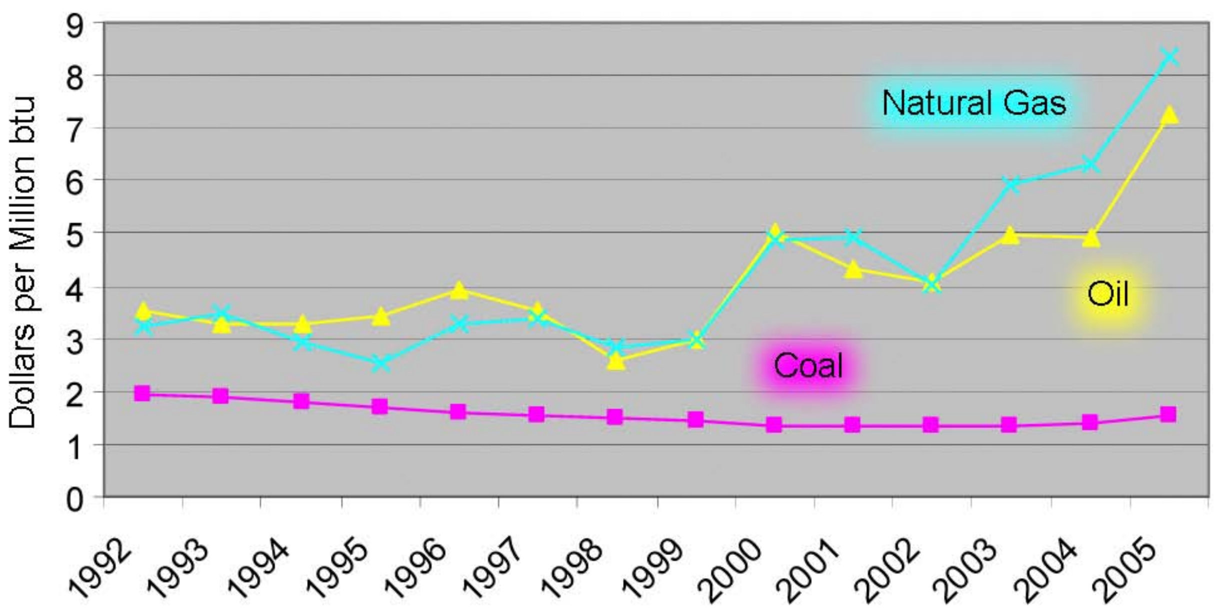


Figure 2-16. Average Electric Utility Fuel Cost, 2005 Dollars

Source: EIA, 2006i; BLS, 2006

The long-term price of natural gas is highly uncertain. The record high prices in October 2005 were due to disruptions in supply caused by Hurricane Katrina. But the underlying upward trend in prices has more persistent causes. According to the DOE's National Energy and Technology Laboratory, "there is a growing consensus among analysts that the current situation is not a transitory feature of the market. Instead, there is a fundamental and potentially worsening gap between our demand for oil and natural gas and our ability to supply it. Despite seemingly large resources, we are becoming increasingly dependent on imports (imports' share of gas supply has tripled since 1985, and imports' share of oil supply has jumped to almost 60% from 27% in 1985). More importantly, the domestic industry has been unable to increase production despite strong price incentives and increased drilling (NETL, undated1)." Production decreased by 0.6 percent in 2004, declining below the 2002 level, and reaching the lowest production level since 1999. The industry in 2004 drilled a record number of gas wells for a single year, and in the summer of 2005 rigs drilling for gas hit a record level. However, production has not increased proportionally, and in fact, not much at all. Production in 2005 was weak and is expected to be about 3 percent lower than the 2004 production level, despite an expected 16 percent increase in natural gas well completions in 2005 (EIA, 2005d). Per-well gas production peaked in 1971, at a level more than three times the 2005 level (EIA, 2006b).

2.2.5.1.2 AECI's Natural Gas Resources

In August 2005 AECI completed the purchase of a partially constructed natural gas combined cycle (NGCC) plant located near Dell, Arkansas. Because of the heat recovery system that is used to power the steam turbine in addition to the combustion turbine, the efficiency of this unit will be about 58 percent, compared to about 33 for a simple cycle plant. The plant was originally constructed to be a baseload plant, but because of the high fuel price, AECI will be operating it as an intermediate load plant. Operation is expected to begin in the spring of 2007 (AECI, 2006g). AECI currently owns, or is acquiring, over 1,500 MW of combined-cycle generation, adequate to meet its intermediate capacity needs.

2.2.5.1.3 Advantages and Disadvantages of Natural Gas

A report of the Northwest Power Planning Council (NWPPC, 2002) succinctly described the advantages of natural gas, at least during the 1990s:

> Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices and low air emissions, combined-cycle gas turbines have been the new resource of choice for bulk power generation for well over a decade. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation and relatively low CO_2 production.

Even though gas prices are no longer "relatively low", the peak period power augmentation is relatively inexpensive because of low initial costs. As shown in Table 2-6, emissions from NGCC plants are lower than emissions from comparable sized coal plants. Figure 2-17 compares CO_2 (the major GHG from fossil fuel power generation) emission coefficients for petroleum, natural gas and sub-bituminous coal, based on a unit of energy produced.

The combination of lower CO_2 emissions per unit of energy and the higher efficiencies of NGCC plants compared to coal burning plants results in the substantial difference in CO_2 emissions between NGCC and coal burning facilities.

Table 2-6. Estimated Annual Air Emissions (tpy) for a 660 MW Net Generating Station From Non-Renewable, Combustible Energy Sources

Combustion Technology	Sulfur Dioxide (SO_2)	Nitrogen Oxides (NO_X)	Carbon Monoxide (CO)	Particulate Matter (PM_{10})[1]	Volatile Organic Compounds (VOC)	GHGs[2]
Natural Gas Combined Cycle (NGCC)	56.6[3]	1,650[4]	250[4]	31.6[3]	34.9[3]	1,830,000[3]
Microturbines	56.6[3]	551[5]	390[4]	31.6[3]	9[5]	4,000,000[5]
Subcritical Pulverized Coal (PC) Powder River Basin (PRB) Coal	2,388[6]	1,910[6]	3,821[6]	356[6]	96[6]	6,700,000[7]
Supercritical Pulverized Coal (SCPC) Powder River Basin (PRB) Coal	2,388[6]	1,910[6]	3,821[6]	356[6]	96[6]	6,700,000[7]
Oil Fired Combined Cycle	1,310[8]	1,240[9]	1,970[8]	111[10]	11[9]	4,060,000[9]

[1] Filterable Particulate Matter with aerodynamic diameter less than 10 microns

[2] Greenhouse Gases

[3] Based upon USEPA AP-42 emission factor for Stationary Gas Turbines, Table 3.1-2a, and net plant heat rate of 6,396 Btu/kWh for a "H" Class Turbine in DOE "Market Based Advanced Coal Powered Systems" Appendix E, May 1999.

[4] Based upon USEPA AP-42 emission factor for Stationary Gas Turbines, Table 3.1-1 with a lean-premix control technology, and net plant heat rate of 6,396 Btu/kWh for a "H" Class Turbine in DOE "Market Based Advanced Coal Powered Systems" Appendix E, May 1999.

[5] USEPA and Southern Research Institute, "Environmental Technology Verification Program Joint Verifiecation Statement for Mariah Energy Corporation 30 kW CHP System" September 2001.

[6] Sargent & Lundy, "New Coal Unit Electricity Generating Technology Evaluation", November 2005. Page 30. Each technology is assumes a 90% capacity factor. Annual emissions do not include auxiliary emission sources.

[7] Based upon USEPA AP-42 emission factor for External Combustion Boiler burning subbituminous coal, Table 1.1-20, the design coal heating value in Sargent & Lundy, LLC. "Associated Electric Cooperative, Inc. New Coal Plan Turnkey Specification for Engineering, Procurement and Construction Services", Addendum No. 3, October 18, 2005, pg. I-28, and net plant heat rate of 8,568 Btu/kWh for a Supercritical Pulverized Coal Boiler in DOE "Market Based Advanced Coal Powered Systems" Appendix E, May 1999.

[8] Based upon USEPA AP-42 emission factor for Stationary Gas Turbines, Table 3.1-2a with a 0.5% sulfur content and FGD control technology, and net plant heat rate of 9,936 Btu/kWh based upon Tables 1.1 and 4.1 of Energy Information Administration "Electric Power Annual with data for 2004", November 2005.

[9] Based upon USEPA AP-42 emission factor for Stationary Gas Turbines, Table 3.1-1 with a water steam injection and SCR control technologies, and net plant heat rate of 9,936 Btu/kWh based upon Tables 1.1 and 4.1 of Energy Information Administration "Electric Power Annual with data for 2004", November 2005.

[10] Based upon USEPA AP-42 emission factor for Stationary Gas Turbines, Table 3.1-2a, and net plant heat rate of 9,936 Btu/kWh based upon Tables 1.1 and 4.1 of Energy Information Administration "Electric Power Annual with data for 2004", November 2005.

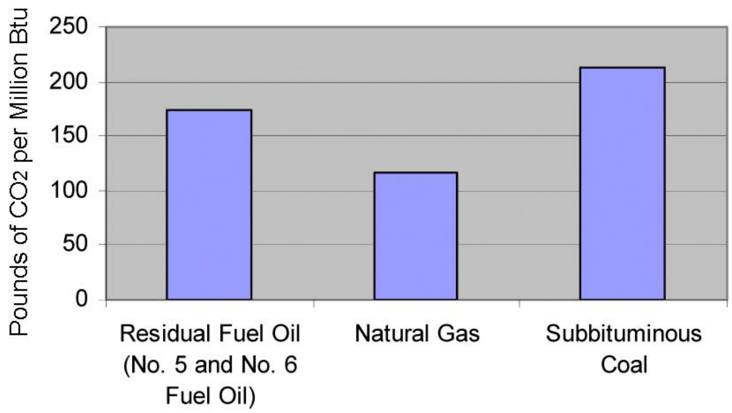


Figure 2-17. Emission Coefficients

Source: EIA, undated

The major disadvantages of natural gas are the relatively high fuel price, the fluctuations in price, and the uncertainty of future prices and supply.

Summary of Reasons for Elimination of Natural Gas as the Energy Source for this Project Production of the needed electricity from natural gas was eliminated from further consideration for the following reasons:

- While natural gas is a good resource for peak and intermediate loads, the high and volatile fuel prices make it uneconomical for the needed baseload energy.

- AECI has substantial planned and existing natural gas resources. Investing additional resources in an energy source with unpredictable and volatile prices, and with uncertainty in future prices and supply was judged to be too high risk. AECI believes that they need a balanced generation mix and adding more natural gas generation would not serve that purpose.

2.2.5.2 Petroleum

2.2.5.2.1 Petroleum Usage and Production in the U.S.

In 2004, the U.S. was the third leading producer of crude oil in the world, after Saudi Arabia and Russia (EIA, 2006h). However, the U.S., by far the leading consumer of oil, consumed about 3 times what it produced, and was the leading importer of crude oil (Figure 2-18). The leading supplier of crude oil to the U.S. is Canada, followed by Mexico. Venezuela, Saudi Arabia, and other Mid-Eastern countries are also major suppliers (EIA, 2006h).

In the U.S., less than three percent of petroleum is used for electric power production (Figure 2-18), and coincidentally, three percent of the electric power generated in the U.S. is from petroleum (Figure 2-2). In the 1970s, petroleum was an important source of electric energy, peaking in 1973 at about 18 percent of U.S. electric energy production (Figure 2-19).

After the Arab Oil Embargo of 1973 and 1974, and the resulting shortages of petroleum products, American businesses began to realize the risks of dependence on imported oil, and those industries that were able began to shift to other energy sources. The real-dollar peak in crude oil prices in the early 1980s helped to accelerate the move away from oil as a source of electricity. In spite of low prices for oil in the mid 1990s, petroleum did not regain its share. Current high petroleum prices are a result of high demand, not just from established industrial countries like the U.S., but now also from China and other developing countries. Demand is expected to increase, as are prices.

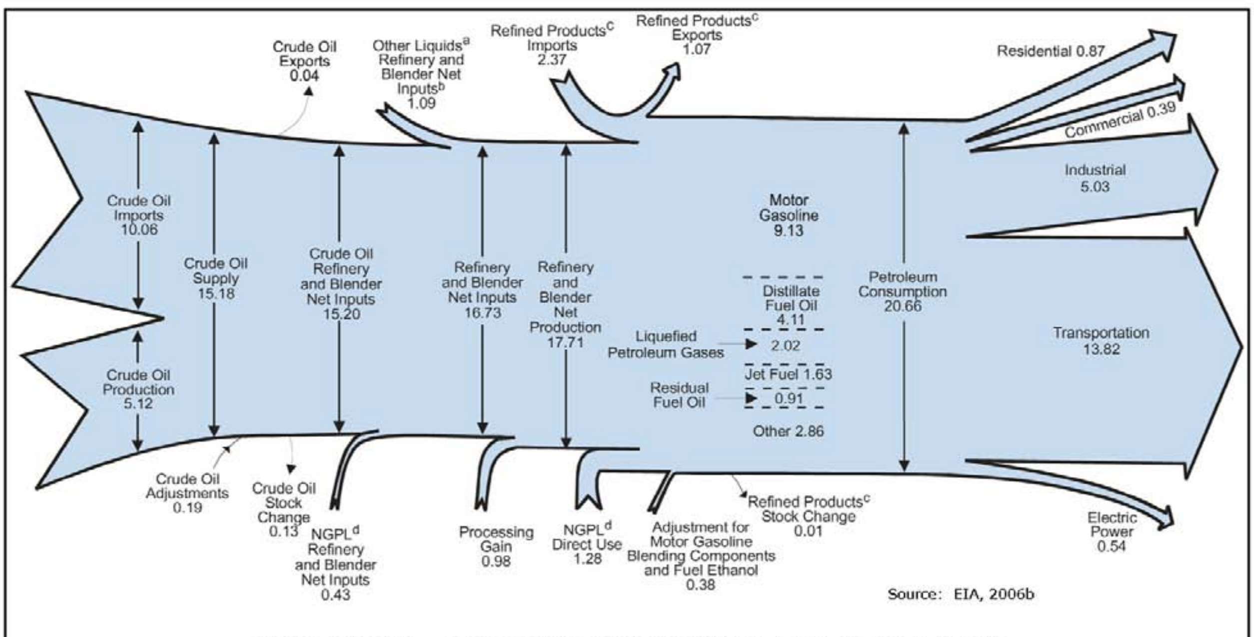


Figure 2-18. Petroleum Flow (Million Barrels per Day)

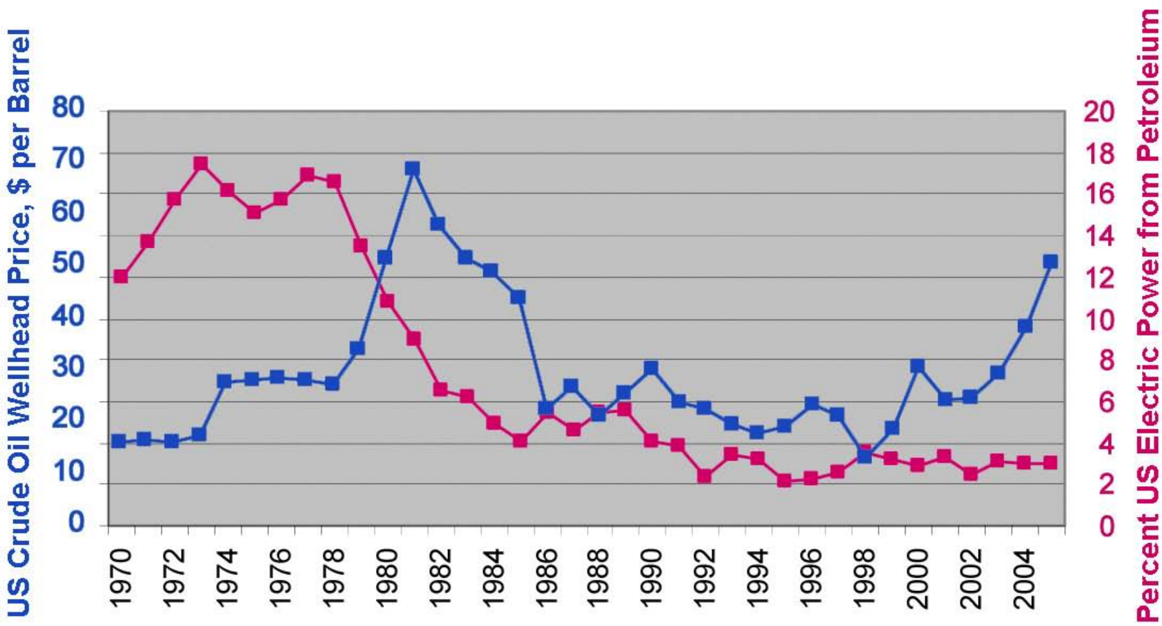


Figure 2-19. US Crude Oil Price (2005 Dollars) and Electric Power Usage from Petroleum

Source: EIA, 2006h; BLS, 2006

An additional concern about oil is reaching the peak of "cheap" oil, when the oil that's relatively easy to pump is depleted, and demand is still very high. When that occurs, and some experts believe the time is not far off, prices will rise steeply (NG, 2004; Hirsch, 2004).

The use of petroleum for electric power generation is expected to continue to decline, and be less than 2 percent of production by 2020 (EIA, 2006c).

Emissions from petroleum-fueled plants are lower than from coal-fired plants, but substantially higher than from natural gas-fired plants (Table 2-6). Petroleum's per British thermal unit (Btu) emissions of CO_2 is only marginally less than coal's (Figure 2-17).[18]

[18] Residual fuel oil is typically the petroleum fuel used to generate electricity.

2.2.5.2.2 Summary of Reasons for Elimination of Petroleum as the Energy Source for this Project

Production of the needed electricity from petroleum was eliminated from further consideration for the following reasons:

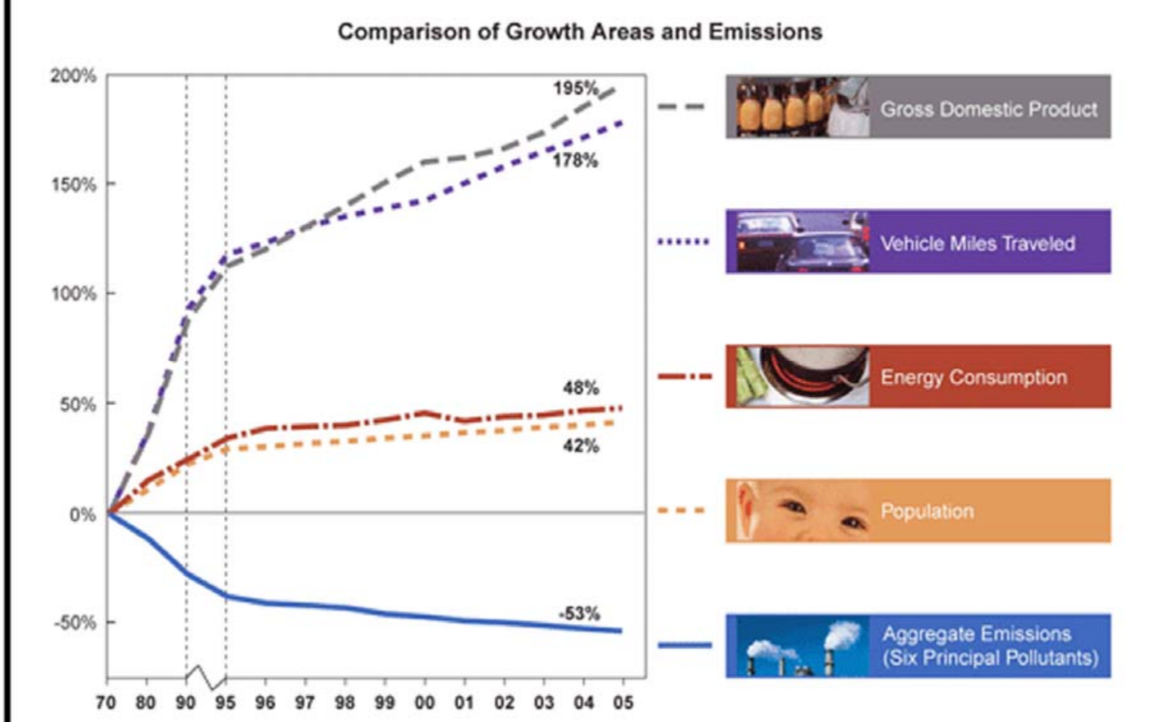
- The high price of fuel and expectation of continued price increases.
- Uncertainty of supply.
- Petroleum has no real advantages, when compared with natural gas or coal, to outweigh the disadvantages.

2.2.5.3 Coal

Coal as an energy source was not eliminated as an alternative. AECI determined that coal is the most cost-effective and reliable energy source available to meet its baseload generation needs. The U.S. has the world's largest coal reserves, enough to last more than 200 years at current consumption rates. Unlike natural gas and petroleum, which have many competing uses that can affect demand and prices, 92 percent of coal is used for electric power production (EIA, 2006b). Also unlike natural gas and petroleum, coal prices have remained fairly constant. EIA projects that coal will provide 60 percent of electricity from the electric power sector by 2030 (EIA, 2006c).

Coal's major drawback is higher emissions (Table 2-6), especially of GHGs (see *Section 3, Affected Environment and Environmental Consequences*, for a detailed discussion of GHGs). However, as a result of converting to low sulfur subbituminous coal and installing pollution control equipment, emissions have been greatly reduced in recent years. AECI, for example, has reduced its system wide sulfur dioxide (SO_2) emission rate 90 percent since 1994, when it converted its coal units to burn 100 percent low-sulfur coal. This conversion cost $200 million in electric generating unit (EGU) capital upgrades plus $342 million to close its high-sulfur coal mine in Missouri (AECI, 2006e). Even with the costs of emission reductions, and in consideration of potential future costs of emissions, including GHGs (see *Section 2.2.5.3.1 Coal—Greenhouse Gases (GHGs)* for a discussion of potential future GHG regulations and costs), AECI has concluded that coal is the most cost-effective and reliable energy source available to meet its needs.

Figure 2-20 shows the dramatic reduction in emissions in the United States even while electric production increased, a result achieved largely by coal-fired electric utilities, including AECI.



Source: EPA at www.epa.gov/air/airtrends/econ-emissions.html

Figure 2-20. Emissions and Economic Growth

Power companies are projected to add flue gas desulfurization equipment to 141 gigawatts of capacity in order to comply with new state or federal initiatives. As a result of those actions and the growing use of lower sulfur coal, SO_2 emissions are projected to drop from 10.9 million short tons in 2004 to 3.7 million short tons in 2030 (Figure 2-21) (EIA, 2006c).

Figure 2-21. Sulfur Dioxide Emissions from Electricity Generation (thousand short tons)

Source: EIA, 2006c

Nitrogen oxides have also been reduced at electric power generating facilities, as a result of improved coal firing techniques and new pollution control equipment. AECI installed selective catalytic reduction equipment at its New Madrid Power Plant at a cost of $100 million and an annual operating and maintenance cost of more than $6 million. At its Thomas Hill Energy Center, AECI modified the air systems on all three units at a total cost of $8.3 million and achieved a 36 percent reduction in nitrogen oxides emissions. As a result, AECI's nitrogen oxides emission rate during the 2005 ozone season was more than 70 percent below the 1994 rate (Figure 2-22) at its coal-based units (AECI, 2006e).

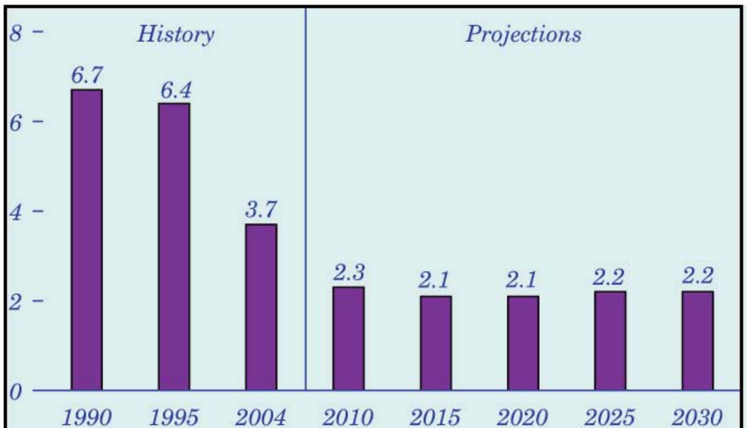


Figure 2-22. Nitrogen Oxide Emissions from Electricity Generation (thousand short tons)

Source: EIA, 2006c

Power companies are expected to add selective catalytic reduction (SCR) equipment to 118 gigawatts of coal-fired capacity in order to comply with both federal and state initiatives; however, as with the requirements for SO_2 compliance, the nitrogen oxide caps are not expected to lead to significantly higher electricity prices for consumers (EIA, 2006c). AECI will be adding SCRs to all three units at the Thomas Hill Energy Center over the next three years. That project is presently in the engineering phase.

As a result of EPA's 2005 regulation of mercury (70 FR 28606), mercury emissions are expected to decline, even while coal use will be increasing, from 53.3 short tons in 2004, to 37.7 in 2010, then to 15.3 short tons in 2030 (Figure 2-23).

Figure 2-23. Mercury Emissions from Electricity Generation (short tons)

Source: EIA, 2006c

2.2.5.3.1 Coal—Greenhouse Gases (GHGs)

CO_2 emissions represent about 84 percent of total U.S. GHG emissions. In the U.S., most CO_2 (98 percent) is emitted as the result of the combustion of fossil fuels, and 39 percent of it is from the electric power sector (EIA, 2005e). (See *Section 3, Affected Environment and Environmental Consequences*, for a detailed discussion of GHGs.)

Figure 2-17 (from natural gas discussion above) compares emissions of CO_2, the major GHG, for equivalent energy units of coal, oil and natural gas.

As shown in Table 2-6, coal burning results in the highest release of CO_2, with petroleum a little less, and natural gas having the lowest emission rate.

The subsections below discuss the potential for future regulation of CO_2 and the potential cost range of such regulation.

Potential Regulation of CO_2

Carbon dioxide is not regulated in the U.S., but there is potential for future regulation. The two likely regulatory techniques would be a cap and trade program, similar to that used for sulfur dioxide, or a simple carbon tax on emissions. This section summarizes current governmental programs and proposals, proposals by private organizations, and public attitudes. While regulation of CO_2 appears likely, and coal burning is one of the major sources of CO_2 emissions, because of its low cost and the abundant domestic supply, coal is likely to remain an important energy source in the United States.

Current governmental programs and proposals. Europe currently has a system in which permits to emit carbon are traded on an open market. During 2006 these permits were selling for about $15 to $30 per metric ton (or tonne, equals 1.1 U.S. tons) of CO_2 (Deutch and Moniz, 2006).

As of August 31, 2006, a bill that would regulate CO_2 has passed the California Senate and Assembly and has been signed into law by the governor. The new law institutes a cap and trade program. It requires the state's major industries, including electric utilities, to reduce GHG emissions to 1990 levels by 2020 (AP, 2006). California is also one of five western states that have teamed up to create the Western Regional Climate Action Initiative (WRCAI) to promote energy efficiency and to slow emissions of GHGs through actions including market-based policies to reduce GHG emissions. Impacts of concern listed in the initiative include reduced snow packs, increased snowmelts, decreased spring runoff, and more severe forest and rangeland fires (WRCAI, 2007).

Another group, the Regional Greenhouse Gas Initiative (RGGI), is making similar plans for the eastern U.S. The RGGI is a cooperative effort by 10 northeast and mid-Atlantic states to discuss the design of a regional cap-and-trade program initially covering CO_2 emissions from power plants in the region. On August 15, 2006, after public input on a draft rule, the participating states issued a model rule, based on a memorandum of agreement. Under the agreement, each participating state would be assigned a base CO_2 emission level, and would be required to reduce emissions annually to achieve ten percent reductions in the base by 2018. The participating states also released a Post-Model Rule Action Plan outlining the actions that will be taken to implement the program and work items that will be undertaken to support program implementation (RGGI, 2006, 2007). The MOA by itself does not mean that reductions will be required. Each state must also go through its statutorily required process to adopt any reduction requirements.

At the federal level, there were a number of legislative proposals filed in the 109th Congress (Yacobucci, 2006). With the exception of the omnibus energy bill which addressed some climate change related issues, none of these bills were enacted into law. These bills indicate a strong interest in the legislative branch to regulate greenhouse gases in such a manner as to have low impact on the country's economy while addressing this issue. Based on comments from the leaders of the 110th Congress, climate change will be an important issue for that body and it is possible that there could be legislation passed although it is speculative as to what any bill that does pass might contain.

There has been legislative action at the state and local level. For example, the state of California recently enacted legislation to limit greenhouse gas emissions. Several northeast states are also working on plans for regional greenhouse gas limits. In addition, many local governments across the country have adopted greenhouse gas limits.

Between March 2006 and February 2007 the EIA responded to five congressional requests for analysis. All five requests involved evaluating impacts of proposals to reduce GHG emissions. EIA notes that these reports "have shown that steps to reduce greenhouse gas emissions through the use of an economy-wide emissions tax or cap-and-trade system could have a significant impact on coal use" (EIA, 2007a).

Business and organization attitudes. While attitudes within the business community run across the board, the number of utilities expecting regulation of carbon dioxide is increasing, and some business groups are advocating regulations.

Three years ago, a national environmental survey of electric generating companies in the U.S. showed that nearly 60 percent of the respondents believed that Congress would enact mandatory limits on carbon dioxide emissions within the next 10 years, and that about half the respondents believed mandatory limits would come within five years (PA Consulting, 2004).

In 2007, a number of businesses are advocating regulation of GHG emissions. The United States Climate Action Partnership (USCAP), a coalition of U.S. companies with total revenues of $1.7 trillion and a collective workforce of more than 2 million people in all 50 states, has recently published *A Call for Action*, (2007), calling for Congress to "enact [climate-protection] legislation as quickly as possible." The document also proposes reduction targets.

USCAP's proposed targets are ambitious; EAI's business-as-usual (no new regulations) CO_2 projections four the U.S. show CO_2 emissions increasing by about a third from 2005 to 2030 (EIA, 2007a). The share contributed by coal is expected to increase from about 35 percent in 2005 to about 40 percent in 2030 in the business-as-usual case (EIA, 2007a). Approximately 90 percent of the coal used in the U.S. today is used to generate electricity (EIA, 2007a).

Another bipartisan group of business leaders, former government office holders and policy analysts, the National Commission on Energy Policy, recently issued its Energy Policy Recommendations to the President and the 100th Congress (NCEP, 2007). For CO_2 emissions the NCEP recommends a starting price "safety valve" of $10 per ton of carbon dioxide equivalent emissions (compared to $7/ton in the Commission's original 2004 proposal) and an increase in the rate of escalation in the safety-valve price to 5 percent per year in real (rather than nominal) terms.

The NCEP report notes that its 2007 proposal "is designed to overcome estimated price differentials for advanced coal systems with carbon capture and storage" (NCEP, 2007). In other words, it is designed to create a carbon penalty sufficiently large to encourage implementation of carbon capture and storage.

Public attitudes about global warming. MIT reports that based on their surveys, the percent of Americans who were unwilling to pay more for electricity to help solve global warming dropped from 24 to 18 percent between 2003 and 2006. In a ranking of environmental problems facing the country, those surveyed in 2003 ranked global warming 6th, behind clean water, clean air, endangered species and other issues. In 2006, when asked to rank environmental problems facing the U.S., those surveyed identified global warming as the top environmental problem (MIT, 2007). These surveys address global warming as a particular issue among other environmental issues. They do not shed light on public attitudes towards environmental issues relative to other issues such as the economy, national security, etc.

Cost of Regulation of CO_2

The cost of potential future regulation of CO_2 emissions is speculative, but an upper limit would be the cost of capturing and storing CO_2 emissions from combustion of fossil fuels. The cost of capturing and storing CO_2 is also speculative, because the technology is not yet available for the needed applications and scale; however, some sources, as summarized below, are using costs of $25 to $30/tonne. This section summarizes the current available information about likely future costs, and concludes that within any reasonably expected cost range, coal is likely to remain an important energy source.

The long-term cost of regulation of CO_2, if it is regulated, would depend on a number of unpredictable factors, including the willingness of the American public to pay more for electricity in exchange for reductions in CO_2 emissions, the development and cost of energy technologies that do not emit GHGs, and the development and cost of carbon capture and storage technologies. As long as coal is used to provide electricity--and because of its abundance and low cost, most analysts expect that to be a long time (for example, MIT 2007, NCEP, 2007)--large reductions in GHG emissions in the power sector are likely to occur only if carbon capture and storage (CCS) technologies are implemented. An upper limit, then, on a CO_2 price would be the cost of CCS technologies to prevent emissions. Industry expectations, current proposals, European experience and estimated technology costs are summarized below.

A survey of utilities who were planning for CO_2 costs in 2003 and 2004 found that several utilities were including in their plans a start date of 2008 to 2010, with estimated CO_2 costs ranging from about $3.2 to $11.6 ($2003) per ton (probability *x* estimated cost), with an average of about $7/ton (Bolinger and Wiser, 2005). EIA estimates for bills in Congress in 2006 were about $6 to $7/ton CO_2 ($2004), with costs beginning in 2012. In some proposals, prices would increase annually to about $14/ton ($2004) in 2030.

As noted above, CO_2 cap and trade permits in Europe were selling for about $15 to $30 per metric ton (tonne) in 2006. The price was generally over about $25/tonne (Capoor and Ambrosi, 2006).

A recent Massachusetts Institute of Technology (MIT) study considered two carbon price scenarios: the high scenario started at $25/ton-$CO_2$ in 2015 and increased at a real rate of 4 percent per year. The report authors believe that the $25/ton CO_2 cost "is significant because it approaches the level that makes CCS technology economic"; however, the technology is not yet sufficiently advanced to make good cost estimates of CCS technology. In any case, the authors conclude that a $25/ton CO_2 cost would result in substantial reductions in both GHG emissions and coal use over business-as-usual projections, but with coal use by 2050 still higher than in 2000 (MIT 2007).[19] (The cost and technology of CCS are discussed in Section 2.2.5.3.2.) MIT's low scenario started at $7/ton in 2010 and increased at 5 percent per year thereafter. (This was based on the 2004 NCEP proposal, which is similar to the bill currently under consideration in the Senate Energy Committee). The low price scenario reached the starting high price scenario 25 years later. Both the Intergovernmental Panel on Climate Change (IPCC)[20] (IPCC) and the MIT studies estimated that a $25 to $30/tonne CO_2 tax would be need to make CCS technology economical (MIT, 2007; IPCC 2005). This is also close to the 2006 price of carbon permits in European trading. Under the NCEP proposal discussed above, the price would reach $25/tonne at about 29 years after implementation. Note that these are inflation adjusted costs.

We note that carbon regulation, under any reasonably foreseeable scenario, is not likely to make coal obsolete as an energy source. The MIT study concluded that even with the cost of carbon capture and storage, coal use would still increase:

> We believe that coal use will increase under any foreseeable scenario because it is cheap and abundant. Coal can provide usable energy at a cost of between $1 and $2 per MMBtu compared to $6 to $12 per MMBtu for oil and natural gas. Moreover, coal resources are distributed in regions of the world other than the Persian Gulf, the unstable region that contains the largest reserves of oil and gas. In particular the United States, China and India have immense coal reserves. For them, as well as for importers of coal in Europe and East Asia, economics and security of supply are significant incentives for the continuing use of coal. Carbon-free technologies, chiefly nuclear and renewable energy for electricity, will also play an important role in a carbon-constrained world, but absent a technological breakthrough that we do not foresee, coal, in significant quantities, will remain indispensable.

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[19] The MIT study dollars are 1997 $US per ton (ton) of CO_2. The executive summary of the document uses "tonne (metric)" in the same context that "ton" is used in the main body of the text.

[20] See Section 3.1.1.2.5 for a discussion of IPCC and its latest reports.

2.2.5.3.2 Coal—Energy Generation Options

Three coal firing alternatives were considered: circulating fluidized bed (CFB), pulverized coal (PC), and integrated gasification combined cycle (IGCC).

Circulating Fluidized Bed (CFB)

The CFB boiler combusts coal at a lower temperature than PC boilers. Basically, a mixture of coal and limestone (to provide the fluidized bed for coal combustion and for absorption/removal of SO_2) are fed into the boiler, with a portion of the combustion air injected into the bottom of the bed. The coal slowly combusts in the boiler while mixing with the limestone. The limestone reacts with the SO_2, forming reaction byproducts which flow with the flue gases to the boiler exit. The heat from the coal combustion is transferred to boiler tubes producing steam. The steam cycle employs a steam turbine generator, condenser, feedwater heaters, and associated equipment. An advantage of CFB boilers is that the long combustion residence time allows for complete combustion of low grade/variable fuel supplies. Figure 2-24 is a schematic diagram of the process.

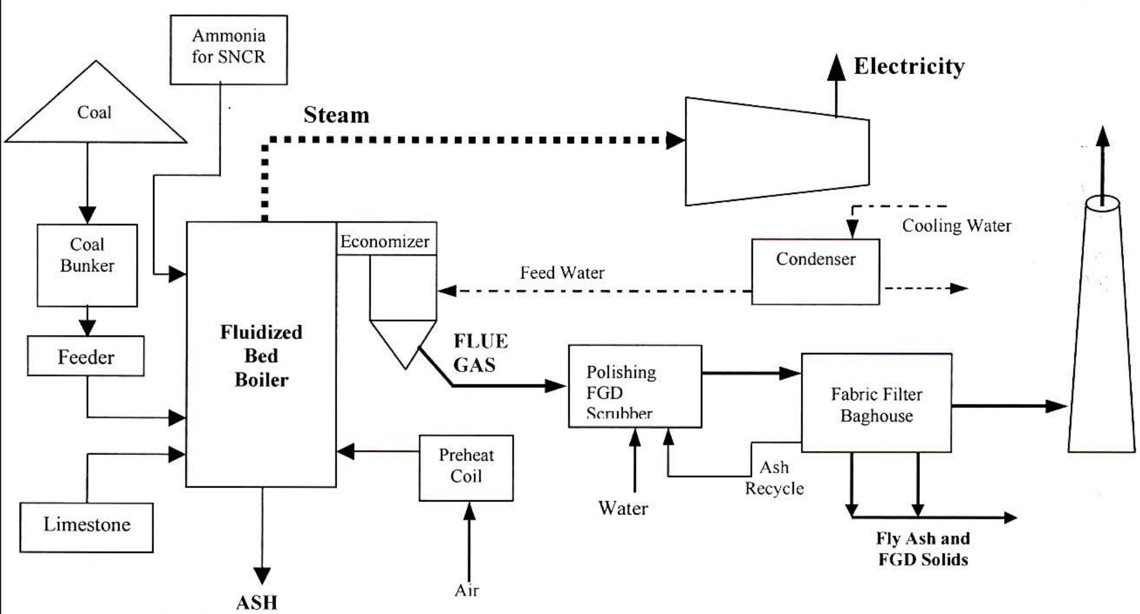

Figure 2-24. Simplified Schematic--Circulating Fluidized Bed Boiler

Source: AECI, 2005b

Because of the lower combustion temperatures, CFB boilers have lower emissions of nitrogen oxides (NO_X) than PC boilers. In addition, CFB units have fewer slagging and fouling problems, since the ash constituents are not subjected to temperatures above their melting points. The large ash particles are removed from the bottom of the boiler and cooled in a water bath prior to removal for disposal or use.

The hot flue gas, carrying unburned coal/char, limestone, fly ash and byproducts from the reaction of the SO_2 in the gas and the limestone, exit the boiler and pass into a hot cyclone. This separation device is a key difference between CFB and PC technologies. There, coarse particles are removed and recycled to the boiler. This recycling of the unburned coal particles raises the coal utilization to about 98%.

The fine particulates leave the cyclone with the hot gas. At the appropriate temperature region of the boiler exit gas path, ammonia can be added, initiating the reactions necessary for selective non-catalytic reduction (SNCR) for reduction of NO_X emissions. From there, the hot flue gases are used in a reheat exchanger (for reheating the steam leaving the high pressure section of the steam turbine) and may be used for feedwater heating. The flue gases then typically pass through a polishing scrubber, which uses lime slurry to react with more of the SO_2 in the gas stream, resulting in an overall high SO_2 removal.

The fly ash in the flue gas stream, along with reaction byproducts, is captured in a baghouse. The fly ash/byproducts mixture is then sent to disposal or re-use, including recycling to the boiler so that any unreacted lime can be used for additional removal of SO_2.

CFB technology provides the following environmental advantages:

- Inherently low production of NO_X emissions, due to the low combustion temperatures,

- Ability to provide for efficient NO_X reduction through the application of SNCR,

- Capture of SO_2 by using crushed limestone in the circulating bed,

- Opportunity for further capture of SO_2 through the use of a spray dryer or polishing scrubber,
- No need for addition of a limestone-based wet flue gas desulfurization (FGD) system to remove SO_2,
- High particulate removal efficiency with a baghouse, and
- Mercury in the flue gas tends to be absorbed/adsorbed in the fly ash and reaction byproduct particulates, which are captured in the baghouse.

Because available unit sizes are smaller for CFB than for PC, AECI would need multiple units, adding to the capital cost. CFB boiler design results in a substantial increase in auxiliary power requirements due to fan power requirements, which results in higher operation and maintenance costs. AECI's total annual cost estimate for CFB is $126,904,000, compared with $111,969,000 for PC, which is 13 percent higher (AECI, 2005b).

Both PC and CFB units are capable of meeting stringent emission limits. Based on emission rates achieved in practice, a PC unit equipped with SCR is capable of achieving a NO_X emission rate comparable to a CFB unit. PC units equipped with FGD have also demonstrated the ability to achieve stringent SO_2 emission rates; however, CFB units equipped with a post-combustion FGD system will probably be capable of achieving somewhat lower SO_2 emission rates (AECI, 2005b).

CFB was eliminated because the PC technology can achieve emissions standards at a lower cost.

PC Technology

In the basic PC technology, coal is crushed to the consistency of a fine powder and then conveyed with air into the boiler, where it is combusted at temperatures of 1,800-3,000 °F. The heat of combustion is transferred to the boiler tubes, which are filled with water. The water is converted to high pressure steam, which is piped to a steam turbine, turning the turbine blades. The turbine is directly connected to a generator; as the generator spins, it generates electricity. The supercritical pulverized coal (SCPC) boiler proposed by AECI is designed to operate at much higher pressures than conventional boilers. This technology is not new, but has been refined in the past decade.

Operation at the higher supercritical pressures is more efficient than subcritical operation, providing a distinct advantage for SCPC technology. Figure 2-25 is a schematic of the PC process for subbituminous coal.

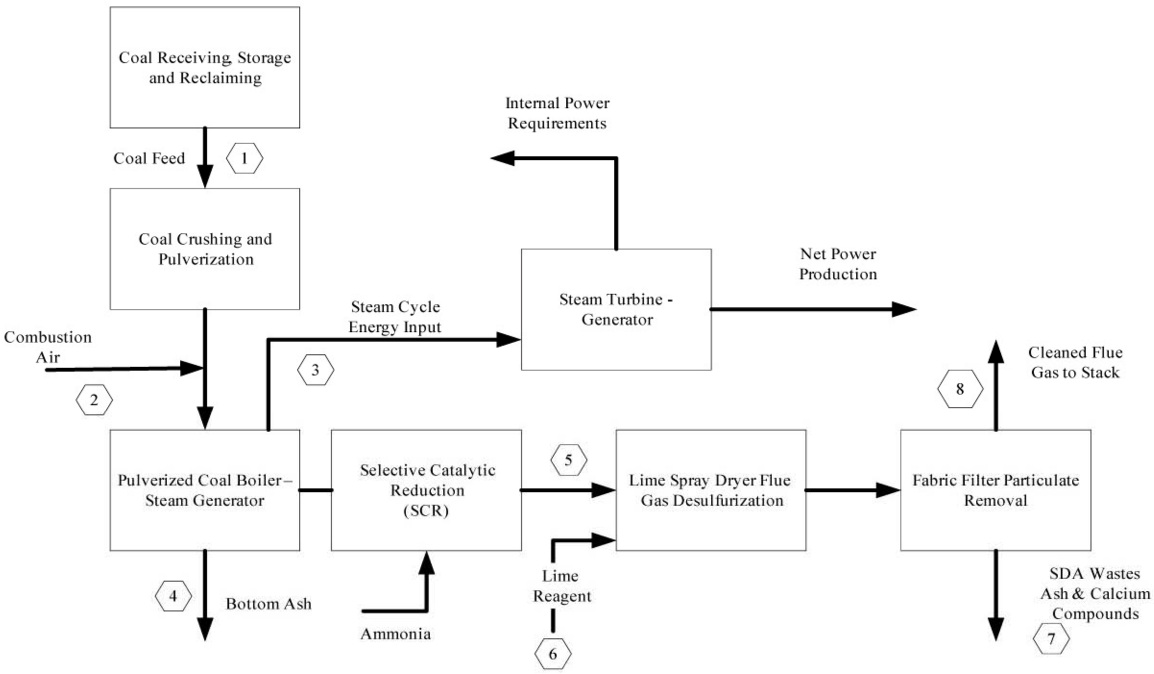

Figure 2-25. Subbituminous Coal-Fired Plant Diagram

Source: EPA, 2006a

Since both the air and the coal contain nitrogen, a portion of the nitrogen combines with oxygen in the air to produce NO_X. At higher temperatures, the rate of NO_X production increases. In order to minimize NO_X production, low-NO_X burners and overfire air are used. These systems provide for a fuel rich combustion environment, followed by the addition of more air later in the combustion process, lengthening the overall combustion zone, cooling the flame, and minimizing the formation of NO_X. The ash in the coal is converted to primarily fly ash, which exits with the hot flue gas. A portion of the ash is converted to a granular bottom ash, which is removed from the bottom of the boiler.

Hot flue gas is transferred from the boiler, through the SCR system for NO_X reduction and into an air heater. The air heater transfers a portion of the heat in the flue gas to the incoming primary air, again increasing the overall plant efficiency. From the air heater the flue gas flows to a lime spray drier FGD unit. The FGD system uses a lime or limestone slurry, reacting with and removing the SO_2 in the exhaust gases. The gases then move to a baghouse for removal of the fly ash and spray drier solids.

In the U.S., there are over 310,000 MW of PC units. Most of these are subcritical units built 25-50 years ago, with steam pressures about 2,450 psi and temperatures up to 1,050^o F, and sizes up to 1,300 MW. There are over 160 SCPC plants in the U.S., although they too were built years ago. Due to recurring problems caused by the very high pressures, SCPC was abandoned as a technology for new PC units in the U.S. Over time, many of these problems were resolved on the existing units, and they were able to increase their availability (the amount of time that a unit is producing or ready to produce electricity) and reduce maintenance costs. The technology is being embraced as the primary PC technology for many new power plants.

Today's SCPC units are achieving availability values of greater than 90% (AECI, 2005f) and efficiencies greater than 38% (AECI, 2006v).

SCPC CO_2 Capture and Compression

It is technically possible to limit CO_2 emissions from a SCPC power plant using a design based on removing 90 percent of the CO_2 in the flue gas exiting the FGD system. An inhibited aqueous solution of monoethanolamine (MEA) is used in a scrubber to remove the CO_2. MEA absorbs CO_2 at cool temperatures and releases CO_2 when heated. CO_2 from the stripper is compressed to a pipeline pressure of 1200 psi by a multi-stage CO_2 compressor and dried.[21] IPCC considers this technology to represent a "mature market" as an industrial separation technology for natural gas processing and ammonia production, and "economically feasible under certain conditions" as a post-combustion technology (IPCC, 2005).[22]

The cost of capture and compression of CO_2 from an SCPC unit would depend on whether it would be applied to a new plant or added as a retrofit.

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[21] "Technology Working Group – Advanced Coal Task Force Western Governors' Association"

[22] Mature market means that the technology is now in operation with multiple replications of the technology worldwide. Economically feasible under certain conditions means that the technology is well understood and used in selected commercial applications, for instance if there is a favorable tax regime or a niche market, or processing on in the order of 0.1 million tons of carbon dioxide per year, with less than five replications of the technology (IPCC, 2005).

CO_2 capture as included in the design of a new SCPC plant. For a new SCPC plant built with carbon capture, the increase in the cost of electricity has been estimated at 66 and 61 percent for MEA (EPRI 2002 and Rubin 2004 as reported in MIT, 2007), 39 percent for oxy-fuel capture (Dillon 2004 as reported in MIT, 2007) and 42 to 66 percent (IPCC, 2005, method not specified), Oxy-fuel capture would use MEA, but would involve a modification to the coal burning method: to increase CO_2 concentration in the flue gas, the pulverized coal would be blown with oxygen rather than air (MIT, 2007). IPCC considers oxy-fuel combustion to be in the "demonstration" phase[23] (IPCC, 2005). The cost per tonne of CO_2 avoided has been estimated at $40 (MIT, 2007) and $9 to $44 (IPCC, 2005). Note that these costs are for capture and compression of CO_2 and do not include transport and storage.

CO_2 capture as a retrofit to an existing plant. The MIT study considers retrofits of existing plants unlikely because of the cost (MIT, 2007).[24] The study considers a rebuild more likely, and estimates that an ultra-supercritical rebuild with MEA of an existing low-efficiency subcritical plant could have an efficiency of 34 percent and produce electricity for about $6.91 cents per kWh (MIT, 2007). An earlier report estimated the incremental costs of electricity for retrofitting an existing SCPC plant. The report did not provide base costs, but a comparison of their incremental values with those from other reports shows that a retrofit would result in energy costs about 78 percent higher than for a plant built with the capture and compression system (ALSTOM, 2001; IPCC 2005). For a retrofit, the estimated costs per ton of CO_2 saved ranged from about $42 to $98/ton ($46 to $108/tonne) (ALSTOM). Note that these costs do not include transport and storage of CO_2.

Because of the energy requirements of the MEA system, overall net power plant efficiencies would be reduced, resulting in a reduction of net power plant output to 77 to 59 percent. Thus, a plant with 660 MW net capacity would be reduced to about 390 to 510 MW net (ALSTOM, 2001).

Capture-ready. A unit can be considered capture-ready "if, at some point in the future, it can be retrofitted for CO_2 capture and sequestration and still be

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[23] Demonstration phase means that the technology has been built and operated at the scale of a pilot plant, but further development is required before the technology is ready for the design and construction of a full-scale system (IPCC, 2005).
[24] Since the proposed plant does not include CCS, for the purposes of this discussion it would be considered the same as an existing plant.

economical to operate" (MIT, 2007). Because of the uncertainty of future design and future policy environment, "significant pre-investment for CO_2 capture is typically not economically justified" (MIT, 2007).

IGCC Technology

IGCC is a power generation process that integrates coal gasification technology with a conventional combustion turbine combined cycle power generation block. IGCC converts coal to a clean-burning synthetic gas (syngas), which is used to fuel a combustion turbine to generate electricity. The hot exhaust from the combustion turbine is used to produce steam that is piped to a separate steam turbine generator, generating more electricity.

In the simplest of terms, an IGCC power plant consists of a gasification island where the syngas is produced, and a combined-cycle power block. The main systems within the IGCC plant include a cryogenic Air Separation Unit (ASU), coal delivery, storage, and preparation coal gasification, heat recovery for production of steam, syngas cleaning for removal of particulate matter (PM), removal and recovery of sulfur compounds, and a syngas-fired combined-cycle power block. A block flow diagram of a typical IGCC facility is shown in Figure 2-26.

In a typical gasification system, the coal is first crushed and fed into the gasifier along with oxygen. The primary gasification reactions are endothermic, meaning that they require the input of heat in order to go forward. A small portion of the coal is partially oxidized, releasing the heat needed for the gasification reactions to occur. It is important to note that although air or oxygen is added to the gasifier, it is only a sub-stoichiometric amount, meaning that the air or oxygen is insufficient to result in combustion of the coal. An energy intensive, cryogenic ASU is used to produce a 95% pure oxygen stream. The addition of the pure oxygen also results in higher gasification temperatures in the range of 2,400-2,900 ^{o}F.

In this temperature range, the constituents in the coal begin to break down, re-combining with water (either in the coal or added as part of the slurry) and the oxygen.

Modern IGCC units utilize the entrained flow gasification technology, with oxygen-blown operation to provide for high carbon conversion and to melt the ash components to inert, glassy slag.

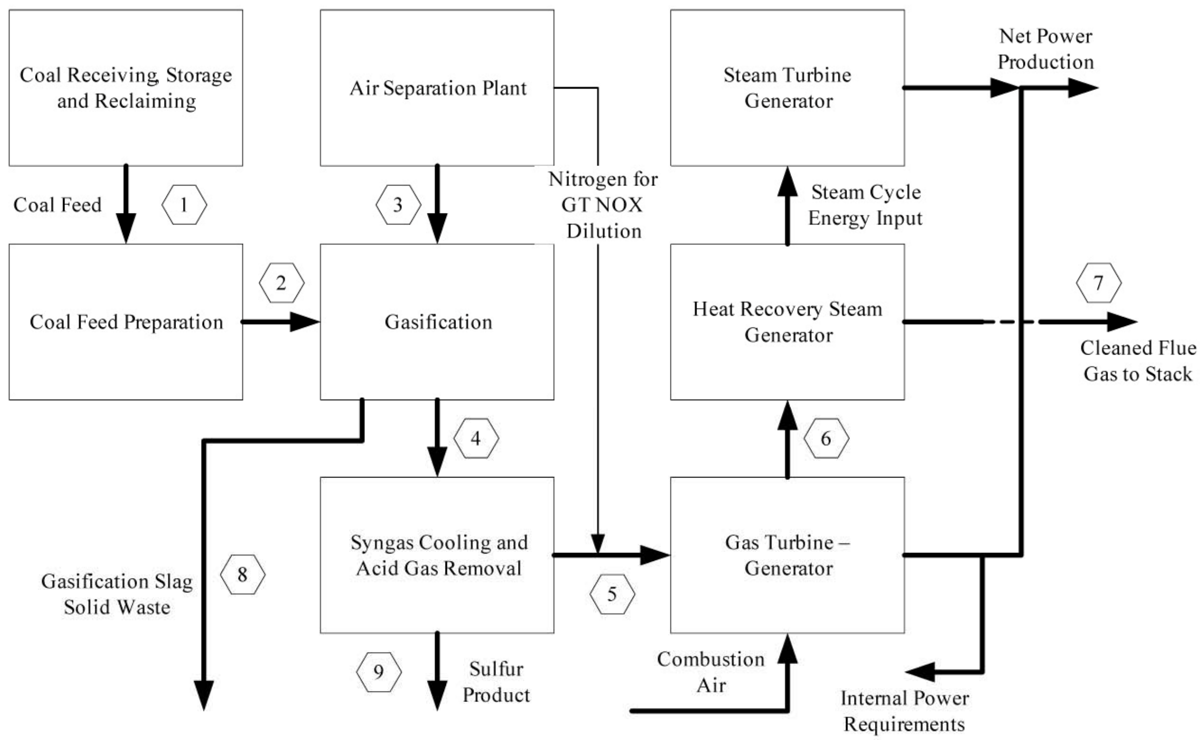

Figure 2-26. IGCC Block Diagram

Source: EPA, 2006a

Most of the heat energy in the feedstock is converted into carbon monoxide (CO) and hydrogen (H_2), and a small amount of methane (CH_4). In a typical oxygen-blown gasifier, the syngas has a composition of about 35% H_2 and 45% CO (Todd, 2000), with the balance mostly water vapor and CO_2. It is this combination of gases that gives the syngas its combustible content and heating value. The heating value of the syngas is typically 250 Btu/scf [standard cubic feet]. For comparison, typical natural gas has a heating value of about 1,000 Btu/scf.

Most of the sulfur in the coal is converted to hydrogen sulfide (H_2S) during the gasification process. A small portion of the sulfur is converted into carbonyl sulfide (COS). Most of the nitrogen in the feedstock is converted to ammonia. The syngas composition leaving the gasifier is determined by the gasifier operating temperature. The sulfur can be easily removed either as molten sulfur or sulfuric acid in amine-based acid gas removal systems. The removed sulfur may have commercial use. The reducing environment also results in the conversion of nitrogen to ammonia, which is then stripped from the syngas and recovered as an ammonia salt in the wastewater treatment system.

Minerals in the coal are subjected to temperatures above their melting points, so that they form a molten ash, called slag. The slag flows from the bottom of the gasifier vessel into a water bath, where it is quench-cooled, forming slag. A small fraction of the mineral matter, along with unconverted carbon char, leaves the gasifier as ash and requires removal downstream in either wet scrubbers or dry ceramic filters. In order to maximize use of the coal, the char can be recycled into the gasifier for further conversion.

The syngas is cooled, cleaned of contaminants, and sent from the gasification island to the combined-cycle power block. The power block generates electricity using two cycles - the gas cycle and the steam cycle. In the gas cycle, syngas is combusted with the hot gases flowing through a turbine, which turns a generator to create electricity. The hot gases exiting the turbine then go to a heat recovery steam generator (HRSG), which uses the hot gases to boil water, creating steam. The steam turns a steam turbine and generator providing more electricity generation. Steam leaving the steam turbine can be further used at the site for space heating, preheating combustion gases, or other thermal processes.

IGCC Commercial Experience

Coal gasification has been in use for over 200 years. Through this global experience in coal gasification, along with the thousands of megawatts of natural gas-fired combined cycle power plants installed in the U.S., the major components of an IGCC facility had been proven in commercial use. However, the integration of these components into a reliable facility for power generation is still unproven.

In the early 1980s, a consortium developed the Cool Water IGCC. This facility, sized at about 100 MW, was the first that combined coal gasification and combined cycle technologies for power production at a semi-commercial scale. It operated from 1984-88 and served as the basis for modern IGCC power plants. (EPRI, 1990).

From 1987-1995, Destec demonstrated its gasification technology at the Dow Plaquemine, Louisiana facility, using 2,400 tons/day of Powder River Basin (PRB) subbituminous coal (Amick, 2005). The syngas was burned in a simple cycle combustion turbine (not in full IGCC configuration), producing 160 MW of power and steam equivalent.

During the 1990s, the DOE implemented its Clean Coal Technology Program. As part of that program, the DOE co-funded two IGCC demonstration projects. These two IGCC plants were the first mid-size commercial scale in the U.S.:

- The Wabash River Repowering Project (W. Terre Haute, Indiana) included a ConocoPhillips coal gasification plant producing syngas from local high sulfur Indiana coals. The syngas was then piped “over the fence” to a repowered Public Service of Indiana power plant that included a new combined cycle power plant. This plant, which began operation in 1995, generates 260 MW.

- Tampa Electric Company’s Polk Power Station (Mulberry, Florida) is a greenfield power plant integrating a GE coal gasification technology with a combined cycle power block on a new site. It began operation in 1996, and generates 250 MW.

The Wabash River IGCC Project design heat rate was 9,030 Btu/kWh (DOE, 1996b). At the end of the first year of operation, it had achieved 9,000 Btu/kWh (Destic and PSI, 1997). Although this project has met its efficiency goals, this is still an efficiency of only under 38%. While the Wabash River plant has a spare gasifier, it is not designed for hot standby service. From 1998 to 1999, Wabash had a 62.4 percent availability, which increased to 73.3 percent in 2000, 72.5 percent in 2001, 78.7 percent in 2002, and 82.4 percent in 2003 (Keeler, 2003). The following issues negatively impacted plant availability (DOE, 2002):

- The ASU never met the performance guarantees.

- The rod mill initially did not produce a fine enough grind.

- Ash depositions lowered gasifier efficiency.

- Brick lining in the gasification system unexpectedly degraded.

- The gasifier taphole became blocked.
- The particulate control system had continuing issues until replaced.

Tampa Electric's Polk Power Station was designed for a heat rate of 8,600 Btu/kWh (an efficiency of 40%) (DOE, 1996a). The actual heat rate has been 9,650 Btu/kWh, or only 35% (Tampa Electric, 2002). Polk Power Station has only one gasifier. The design availability for the Polk Power Station was 85% (Tampa Electric, 1996). In 1998, Polk had just over 60 percent availability, which increased to 80 percent in 2000, 70 percent in 2001, and 74 percent in 2002. The following issues negatively impacted plant availability and efficiency (Tampa Electric, 2002).

- Failure of gas exchanger tubes damaged the combustion turbine, which causes a persistent heat rate penalty.
- Convective syngas coolers exchangers experience ongoing pluggage.
- The gasifier is producing twice as much carbonyl sulfide as expected.
- The quantity of unconverted carbon in the gasifier is twice as expected and increases capital and operations and maintenance (O&M) costs as well as a heat rate penalty.
- The main air compressor did not perform as specified, which was caused by plugging as well as incorrectly operating inlet guide vanes.
- Several issues were encountered with the slurry feed system including slurry screen opening size, rod mill malfunctions and uncertainties in quantities of slurry additives.
- Instrumentation failures after five to six years of operation.

Neither of these IGCC plants has achieved the 40% efficiency level. The next generation of slurry fed IGCC power plants will be designed to provide 36-40% efficiency. Although further improvements in IGCC are expected, slurry fed IGCC technology does not, at this time, have significant lower emissions than SCPC. Both plants had an average SO_2 emission rate of 0.1 lb/MMBtu [one million Btu]. Average NO_X emissions were 0.15 lb/MMBtu, and particulate emissions below the detection limit (DOE, 2002). Additional NO_X emission reductions through add-on technologies of Dry Low NO_X combustors or SCR are not available because of inherent IGCC design limitations. Dry Low NO_X combustors rely upon diluting fuel gas with combustion air or inert gas. There is a high H_2 component in syngas, which has a very high flame speed. In order to obtain sufficient dilution, flame instability and flame-out occurs. SCR when used on a flue gas with residual sulfur, like IGCC syngas, sulfur compounds are formed which plug HRSG tubing (Tampa Electric, 2002).

These two IGCC plants were the first mid-size commercial scale in the U.S. During that same timeframe, IGCC plants were developed in Europe and Japan with government co-funding:

- The Willem Alexander Plant (Buggenum, The Netherlands) was a new plant constructed by Demkolec, and later acquired by Nuon. The facility uses a Shell dry coal-feed gasification technology. It generates 253 MW net and began operation in 1993.

- Elcogas Puertollano IGCC Plant (Puertollano, Spain) is a new facility uses a Shell coal gasification technology. It generates 250 MW net and began operation in 1998.

- The Negishi IGCC facility is owned by Nippon Petroleum Refining Co. and started commercial operation in June 2003. At 342 MW (net) it is the largest IGCC plant currently in operation. The facility is based on a GE gasifier and it uses a variety of feedstocks. As of August 15, 2003, the facility had 1,128 hours of operation with a 96.1 percent gasification availability (Rosenberg et al, 2005).

One of the key design points of the Willem Alexander Plant was the integration of the combustion turbine (CT) and the air separator unit (ASU). The original ASU and combustion turbine compression and control scheme caused fluctuations resulting in start-up problems and nuisance shutdowns. Shell and Siemens have since modified the CT, ASU and plant control schemes to allow reliable operation with full air integration. The latest available data from the Nuon Shell IGCC plant in the Netherlands lists an efficiency of 41% higher heating value (HHV) with a Siemens CT. The Shell 600 MW IGCC study noted above is based on a higher firing temperature CT. This would provide for increased IGCC efficiency. However this CT has not yet been commercially operated on syngas. The plant operated at 84 percent availability in 2002, 87 percent in 2003, and over 95 percent through May 2004 (Rosenberg, et al, 2005).

The Puertollano IGCC plant has had availability around 60 percent in 2000 and 2001.

Since those units went into operation, companies around the world have developed gasification plants, as well as IGCC plants, using a variety of feedstocks. However, no new coal-based IGCC plants have started up in the U.S.

For power plants, high availability (greater than 90%, as experienced with PC units) is a key factor in AECI's generation expansion plan. The new coal-based generation must be available to serve AECI's customers. The availability of IGCC plants has not been nearly as good as SCPC. Based on the lessons present designs for the next generation of IGCC power plants are incorporating significant amounts of spare equipment. The purpose of the spare equipment is to increase the overall IGCC availability to 90%. However, it will be 5-6 years before it is known whether or not these design concepts are successful and if IGCC availability is able to achieve the high availabilities required by AECI and provided by existing PC technology.

Because of these initial difficulties financial ratings agencies remain skeptical of the IGCC technology. "Although projects have been proposed using IGCC technology, which offers the best thermal efficiency and environmental performance, Standard & Poor's is not optimistic about the prospects for this technology because it is very expensive and has the poorest commercial record with low availability, high O&M costs, and long start-up times." (Credit Suisse, 2004).

IGCC CO_2 Capture and Compression

Several studies have been conducted over the past 15 years on the costs of CO_2 capture from various power plant technologies. Most studies concluded that the costs of pre-combustion CO_2 capture from syngas in an IGCC plant was much lower than post combustion removal from Pulverized Coal (PC) or NGCC plants. While this remains true for bituminous coals, the costs of CO_2 removal do vary significantly between the various coal gasification technologies and the advantage in capture costs over PC plants will depend very much on the gasification technology selected. Most studies focused on the use of bituminous coals but some have included sub-bituminous coal and lignite. Indications are that at the current state of gasification technology for low rank coals the Cost of Electricity (COE) for IGCC with CO_2 capture is close to the COE from PC plants with CO_2 capture for sub-bituminous coals and maybe greater for lignite. IGCC does not appear to compete with PC plants for PRB coals (Holt et al, 2003). In neither case has carbon capture been demonstrated on a utility-scale project. The capture projects to date have been for commercial scale projects. The cost of electricity increases substantially with CO_2 capture and pressurization for both SCPC (up to 75%) or IGCC (up to 50%)[25].

CO_2 capture as included in the design of a new IGCC plant. Recent estimates of the increase in the cost of electricity of CO_2 capture and compression for IGCC units are 21 to 78 percent (IPCC, 2005) and 25 to 40 percent (MIT, 2007). IPCC estimates the cost of avoided CO_2 emissions at $14 to $53/tonne for IGCC (IPCC, 2005).

CO_2 capture as a retrofit to an existing plant. The MIT study reports that "retrofitting an IGCC unit would appear to be less expensive than retrofitting a PC unit, although it would not be an optimum CO_2 capture unit. Pre-investment for later retrofit would generally be unattractive and will be unlikely for a technology that is trying to establish a competitive position. However, for IGCC, additional space could be set aside to facilitate future retrofit potential" (MIT, 2007).

Carbon Dioxide Transport and Sequestration (Storage)

For either SCPC or IGCC, the fate of captured CO_2 is also unknown. Currently, the captured CO_2 can either be used as a food grade raw material or sequestered (stored), although for the volumes considered, only an inconsequential part could be used as raw material. Most CO_2, after removal and compression at a plant site, would need to be piped to a location where it could be permanently sequestered (stored), most likely underground. Sequestration is the process of injecting into geologic (oil and gas reservoirs, coal bed methane, or saline) formations or deep-ocean formations. The effectiveness of sequestration techniques in retaining the CO_2 is still under study and has not been proven.

[25] "Technology Working Group – Advanced Coal Task Force Western Governors' Association"

Subsurface CO_2 injection for enhanced oil recovery (EOR) is a mature market technology in the oil industry. IPCC considers geological storage in either gas or oil fields or saline formations to be at the stage of "economically feasible under specific conditions"[26] (IPCC, 2005), but the scale of any existing project is small compared with the massive scale that would be needed for storage of CO_2 from electricity generation. According to the MIT report, EOR experience is of limited value for utility-scale sequestration because "regulations differ, the capacity of EOR projects is inadequate for large-scale deployment, the geological formation has been disrupted by production, and EOR projects are usually not well instrumented" (MIT, 2007).

The DOE's National Energy Technology Laboratory (NETL), working with several Regional Carbon Sequestration Partnerships, is evaluating various geologic storage options throughout the U.S. and Canada, and has published a *Carbon Sequestration Atlas* (NETL, 2007). The MIT study notes that there are currently three well-established large-scale injection projects with measurement, monitoring and verification, in Norway, Canada, and Algeria, with the first beginning in 1996, and none have detected leakage (MIT, 2007). However the scale of these projects is still small compared with what would be needed if coal is to be burned and CO_2 sequestered. Issues such as leakage, evaluation of storage capacity, and potential for induced earthquakes could be appropriately assessed only with very large-scale projects. The MIT study considers the increased funding of sequestration technology to be an imperative (MIT, 2007). Legal and regulatory issues unique to large-scale storage would also need to be addressed.

A range of transport and injections costs has been reported at $0.5 to $8/tonne of CO_2 (MIT, 2007) and $1 to $19/tonne of CO_2 (IPCC, 2005).

Advantages and Disadvantages of IGCC

The main advantage of IGCC is that "it is estimated to have lower cost than pulverized coal with [carbon dioxide] capture" (MIT, 2007). However, "neither IGCC nor other coal technologies have been demonstrated with CCS" (MIT, 2007). Other advantages are that IGCC may have potential for reduced

[26] Economically feasible under specific conditions means that the technology is well understood and used in selected commercial applications, for instance if there is a favorable tax regime or a niche market, or smaller scale processing, with few (less than 5) replications of the technology (IPCC 2005).

sulfur dioxide emissions and grants through EPAct2005 may be available to offset costs (AECI, 2005b).

IGCC disadvantages include:

- Higher capital costs and difficulty obtaining firm pricing due to technology risks.
- Actual emissions from operating IGCC plants have not demonstrated the ability to achieve the projected IGCC emission goals.
- Vendor predictions for availability are in the range of 75 to 30 percent; a spare gasifier train would be needed in order to attempt to achieve acceptable availability (greater than 90%).
- There are substantial operating complexities associated with the ASU, gasification plant, gas cleanup system, power plant, and sulfuric acid plant.

AECI has estimated the total cost of IGCC is approximately 23 percent higher than PC. Because of the cost availability, the lack of a commercially demonstrated system with proposed improvements, and other disadvantages of IGCC compared with PC, PC was retained as the proposed technology alternative over IGCC. However, because of its advantages IGCC is still considered a reasonable technology and was retained for detailed evaluation. The only difference in the impacts of the two technologies is with air resource impacts, which are discussed in *Section 3.1, Air Resources*.

2.2.6 Nuclear Power

Nuclear power is a steam-based technology in which the heat to produce the steam is derived from controlled nuclear reaction. It is emission-free.

2.2.6.1 Nuclear Power in the U.S.

The U.S. is the world's leading producer of nuclear energy (Figure 2-27). The year 2004 was a record year for nuclear energy production in the U.S. and a new record will probably be set in 2006. In 2005, there were 104 U.S. commercial nuclear generating units that were fully licensed to operate.[27]

[27] Note: One reactor, however, Brown's Ferry Unit 1 has been shut down since 1985, but the

Together, they provided about 21 percent of the U.S. electric energy (Figure 2-2). As shown in Figures 2-3 and 2-28, nuclear energy production in the U.S. has increased fairly steadily since about 1970. The industry has realized dramatic increases in capacity factors since 1989 (Figure 2-28). In 1980 the average capacity factor for U.S. nuclear plants was 56 percent; in the summer of 2006, most plants were operating at 100 percent capacity (IAEA, 2003; NRC, 2006c). Nuclear plant operating costs are lower than both fossil steam and gas (Figure 2-15). An increasing need for additional power in the U.S. along with improved economic and safety performance have led many licensees to renew their operating licenses for an additional 20 years beyond the their initial 40-year limits (IAEA, 2003; NRC, 2006a).

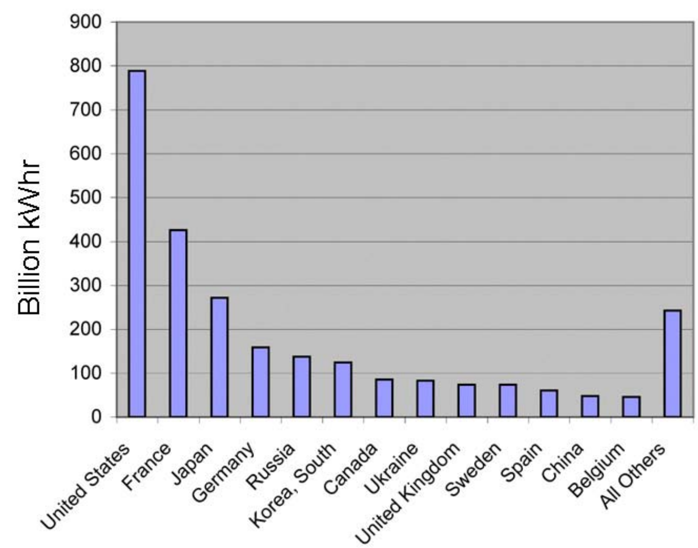

Figure 2-27. World Net Nuclear Electric Power Generation, 2004

Source: EIA, 2006e

Generating electricity from existing plants is one thing; building new ones is quite another. No new orders for steam supply systems for nuclear power plants in the U.S. have been placed since the Three-Mile Island accident in 1979 (Figure 2-29). Of the total of 259 units that have been ordered in the U.S. since the beginning of the nuclear industry, 124 were canceled, often after considerable investment. Twenty-eight plants have shut down; that is, they have permanently ceased operations. The most recent operating license was issued in 1996 (EIA, 2006b). Nuclear power in the U.S. has been characterized by long construction periods and high capital costs (Figure 2-14), often double or more the original estimate (Aston, 2006).

license was renewed in 2006. Therefore, some sources cite only 103 units.

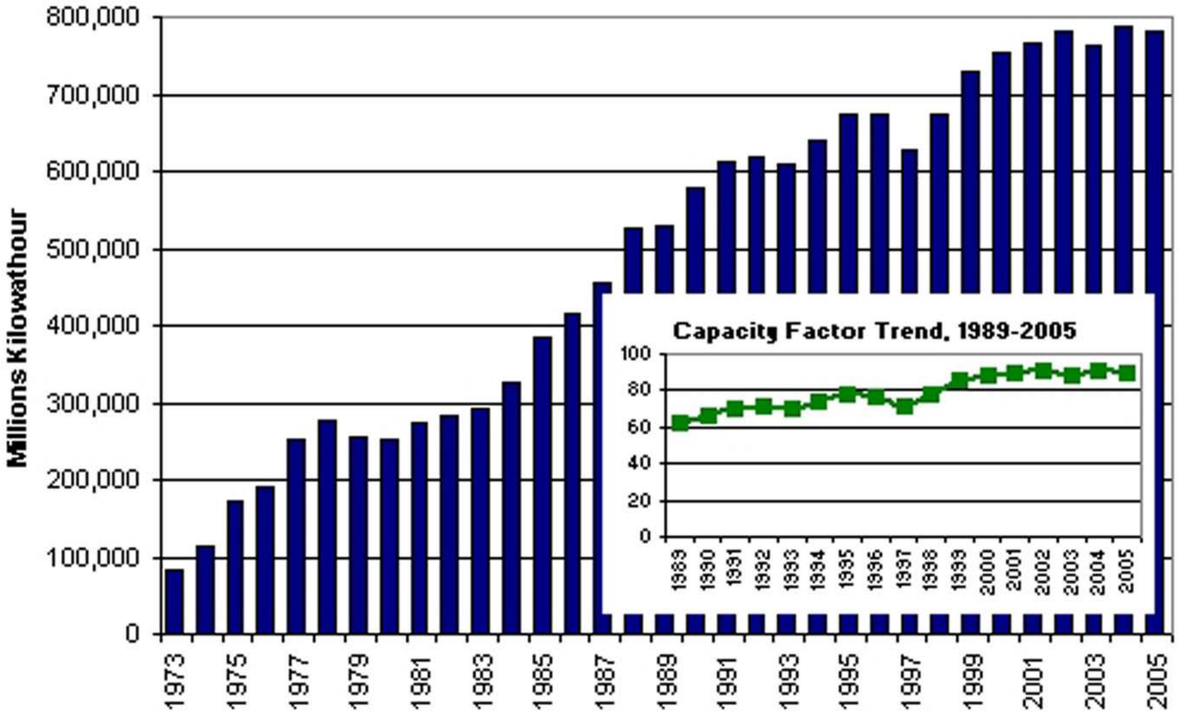

Figure 2-28. US Nuclear Generation, 1973 - 2005

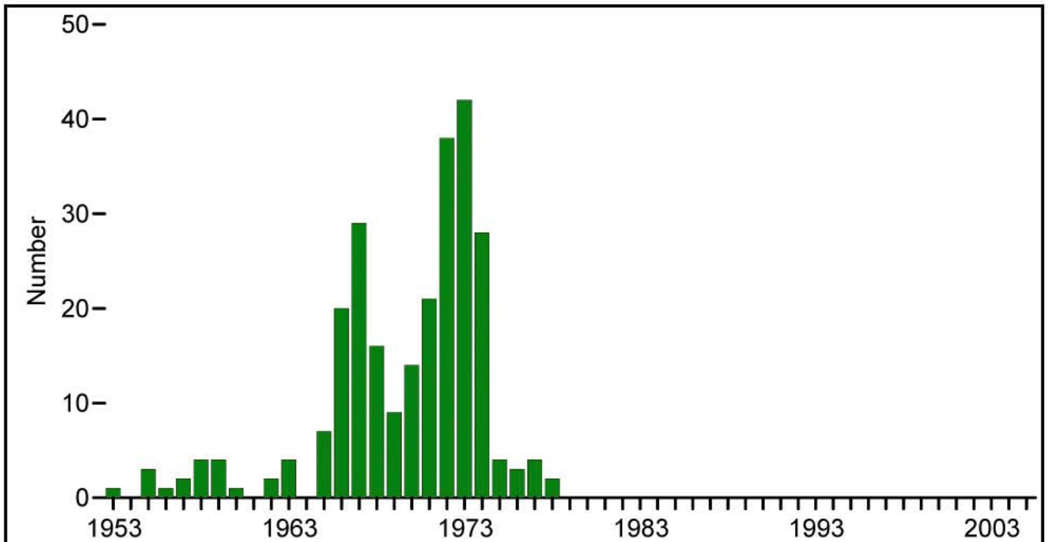

Figure 2-29. Nuclear Steam Supply Systems Ordered

Source: EIA, 2005b

In the U.S., the average time from construction start to plant operation has been 9.3 years, with a minimum of 3.4 years and a maximum of 23.4 years (University of Chicago, 2004).

In addition to construction cost risks, nuclear power has other disadvantages. Waste from all nuclear generation in the U.S. is in temporary storage, because a permanent repository has never been approved, although Yucca Mountain has been under study since 1978 (EPA, 2005c). Public perception of safety is another concern.

In spite of all these obstacles, nuclear power has vast theoretical potential (there is no shortage of the fuel), and it emits no GHGs or other air pollutants. Recent studies have concluded nuclear power is one of the few feasible options for reducing GHG emissions and that development will require efficiency improvements, government support, and some type of tax on carbon sources (University of Chicago, 2004; MIT, 2003).

In response to the EPAct2005 $2 billion set-aside for standby support to cover construction cost legal and agency delays for the first six reactors granted licenses, as well as production tax credits, sixteen utilities have announced plans to apply for nuclear licenses. However, investors are reportedly wary (Aston, 2006). The industry hopes to build plants for $1,500 to $2,000 per kW, which could make them cost-competitive with coal; but the cheapest plants recently built, all outside the U.S., have all cost more than $2,000 per kW. Because of the risks and large potential investment, only the largest and most diversified utilities are likely to be granted licenses, and many of them in consortiums. Energy Secretary Samuel Bodman feels certain that the EPAct2005 set aside will lead to the first six covered reactors beginning construction by 2011, but is concerned that there is not sufficient incentive to build more (Aston, 2006)

2.2.6.2 Summary and Conclusions

The disadvantages of nuclear power are:

- Historically the capital costs have been very high, with large schedule and cost overruns; while future capital costs have the potential to be much lower, there is no recent U.S. experience.

- The waste is highly toxic and persistent, and the issue of permanent disposal has not been resolved.
- Accidents can potentially have much more serious consequences than accidents at other facilities. The public tends to react more strongly to accidents associated with nuclear power.

The primary advantages of nuclear power are:

- It is emission-free.
- Operating costs are competitive with other technologies.
- The US has a plentiful and reliable fuel supply.

The utilities that are actively pursuing development of new nuclear plants (for example, TXU, NRG, TVA Energy, Southern Company, Dominion) are very large, diversified, and experienced in the nuclear field; even so, gaining approvals for and constructing these initial projects will be challenging. Nuclear power, at its current stage of redevelopment, is simply not an option for AECI for the time frame during which the current project is needed. While AECI supports continued nuclear development, they do not have the qualifications or resources at this time.

2.2.7 Summary of Technology Alternatives Assessment

Supercritical pulverized coal (SCPC) electric generation technology was retained as AECI's proposed technology because it is most cost-effective, is well-developed and can achieve the required emissions standards. Integrated gasification combined cycle (IGCC), a coal technology that involves gasification of coal then use of the gas in a conventional combined-cycle facility, was also retained for detailed consideration. The IGCC technology is not as well-developed as SCPC and would be costlier; however, if carbon dioxide capture becomes a requirement in the future, it presently offers the least costly potential for carbon dioxide capture. IGCC was retained for that reason.

Technology alternatives eliminated from detailed consideration are summarized in Table 2-7.

Table 2-7. Technology Alternatives Eliminated from Detailed Consideration

Alternative	Reasons for Elimination
Renewable Non-Combustible Energy Sources	
Wind	• Intermittent source, not suitable for baseload needs. • AECI's service area does not have adequate resources to consider wind for this project.
Solar—Photovoltaics	• Intermittent source, not suitable for baseload needs. • Not cost-competitive.
Solar—Concentrating Solar Power	• Solar resources not available in AECI service area. • Not cost-competitive.
Hydroelectric	• Resources in AECI's service area are suitable only for peaking needs, not baseload. • Inadequate developable resources. • Large risk based on past experience in US.
Geothermal	No resources available.
Renewable Combustible Energy Sources	
Wood	Not cost-competitive.
Municipal Solid Waste	Not cost-competitive.
Landfill Gas	Not cost-competitive.
Other Waste	Not cost-competitive.
Alcohol Fuels	Not cost-competitive.
Non-Renewable Combustible Energy Sources	
Natural Gas	• Unpredictable and volatile prices. • Uncertain supply.
Petroleum	• High price of fuel and expectation of higher future prices. • Uncertainty of supply. • No real advantages to coal or natural gas.
Microturbines	Not cost-competitive.
Coal—circulating fluidized bed technology.	Because of the size of the proposed unit, AECI can achieve comparable emissions reductions at a lower cost with pulverized

Table 2-7. Technology Alternatives Eliminated from Detailed Consideration

Alternative	Reasons for Elimination
	coal; therefore it has no advantages over pulverized coal technology.
Nuclear	At the current stage of nuclear redevelopment, AECI does not have the qualifications or resources at this time.
Energy Efficiency and Conservation	Based on available information, any reasonably anticipated energy savings would be insufficient to offset the need for new capacity.

2.2.8 Coal-Fired Plant Siting Studies

This section summarizes AECI's siting studies for a coal-fired facility, which culminated in the identification of a proposed site near Norborne, Missouri, and an alternate site near Big Lake, Missouri. Two major studies were done: one in 1981 and one in 2003-2004. While some of the 1981 study information is no longer relevant, much is, and it provided a foundation for the 2003-2004 study.

2.2.8.1 1981 Siting Study

In 1981, AECI conducted a siting study for a 1,200 MW coal-fired power plant (AECI, 1981). The purpose of the study was to identify sites that were "technically and economically feasible, environmentally compatible, and socially acceptable." The result was the identification of three potential sites, representing a variety of siting options. This section summarizes that study, and the criteria used.

Since almost all of AECI's transmission facilities and most of its customers and projected future needs are in Missouri, the study was limited to Missouri.

2.2.8.1.1 Water Source

Since a coal-fired plant has large water requirements, water supply is critical. The water requirements for the 1,200 MW plant using closed-cycle cooling were estimated to be 24 cubic feet per second (cfs), which is about 10,800 gallons per minute (gpm) (AECI, 1981).

Streams

The 1981 study identified all streams and reservoirs in Missouri that could provide 24 cfs.

To avoid impacting streams, only those with a low flow at least 10 times greater than the required plant flow were considered (that is, only streams with a low flow of greater than 240 cfs were considered). Low flow is defined as the river's lowest flow for 7 consecutive days with a once in ten year recurrence interval (7Q10 flow). Streams in Missouri that met this criterion were all parts of the Missouri and Mississippi Rivers within or adjoining the state; and portions of the Osage, the Gasconade, the Current, and the Meramec Rivers. Those streams and stream segments that met the 240 cfs 7Q10 flow are shown in Figure 2-30. All other streams in Missouri would require storage to provide adequate water supply.

The 1981 study eliminated all rivers except the Missouri and Mississippi from further consideration as water sources for various reasons. The study reported that the Current River was eliminated because it was designated as a Wild and Scenic River.[28] The Current River is not presently a Wild and Scenic River; however, since sometime before 1981 almost the entire river has been either within the Ozark National Scenic Riverway, which is part of the National Park System, or within the Mark Twain National Forest; therefore elimination in 1981 was appropriate. The Gasconade River was eliminated because it was under consideration as a Wild and Scenic River.[29] The Osage River downstream of Bagnell Dam met the flow requirements. Because of its proximity to Lake of the Ozarks, a large and important recreational area, and its potential future status as a protected river, the Osage River was eliminated. While the Meramec River in the St. Louis area met the flow requirements, it was eliminated because the area as a whole was eliminated for air quality reasons (AECI, 1981). The study also considered 15 miles the maximum practical distance of the plant from the water source. Proximity to the water source is desirable for a number of reasons: lower cost, fewer impacts from the pipeline construction, and greater reliability with a shorter line.

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[28] Wild and Scenic Rivers Act, 1968, PL 90-542

[29] The Gasconade River has been recommended by the state as a Wild and Scenic River, but it has not yet been designated as such by Congress.

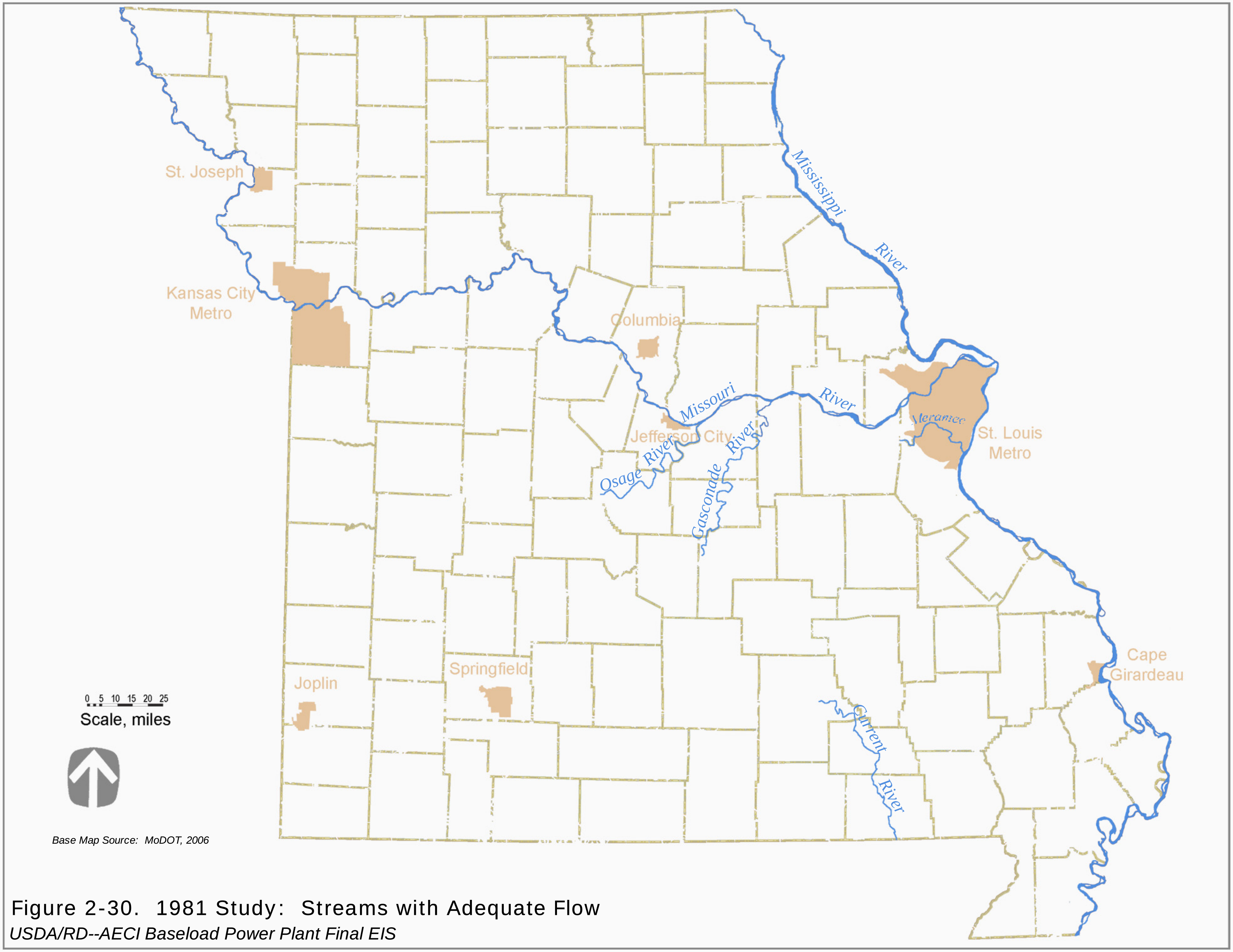

Figure 2-30. 1981 Study: Streams with Adequate Flow

USDA/RD--AECI Baseload Power Plant Final EIS

Existing Reservoirs

The 1981 study evaluated availability of water supply from existing reservoirs. The study reported that all the large reservoirs in Missouri, shown in Figure 2-11, are under the jurisdiction of the USACE, except for two: Lake of the Ozarks, which was controlled by Union Electric (now Ameren UE); and Thomas Hill Reservoir, which was, and still is, owned by AECI and discussed elsewhere in this document.[30] The study concluded that, because of legal restrictions limiting water use from USACE reservoirs, none of the water from these reservoirs would be available.

2.2.8.1.2 Regional Avoidance Criteria

The 1981 study identified the following other regional avoidance areas: parts of National Park System, large metropolitan areas, National Forests, designated Wilderness Areas, and National Wildlife Refuges (NWR). These areas are shown in Figure 2-31, except that Wilderness Areas are not shown because they are all located in a National Forest or NWR.

2.2.8.1.3 Coal Availability

The 1981 study considered Missouri coal, Illinois coal and western coal as possible fuels, and either trains or Mississippi River barges for transport.

2.2.8.1.4 Identification of Sites

Based on water supply, fuel access, regional avoidance criteria and other local constraints, the report identified 18 sites, then narrowed the field to three potential sites in three different geographical areas: Lusk in southeast Missouri, Norborne in northwest central Missouri, and Watson, in the far northwest corner of the state (Figure 2-32). The water supply for Lusk would have been the Mississippi River, and Illinois coal was to be supplied by barge. The water supply for Watson and for the Norborne site would have been the Missouri River and western coal was to be supplied by rail.

Ultimately, AECI identified Watson as proposed, and purchased the property. However, during the 1980s electric power demand was below projections, the additional capacity was not needed, and the plant was not constructed.

[30] The study overlooked Lake Taneycomo, which is privately owned and would not be available for water supply.

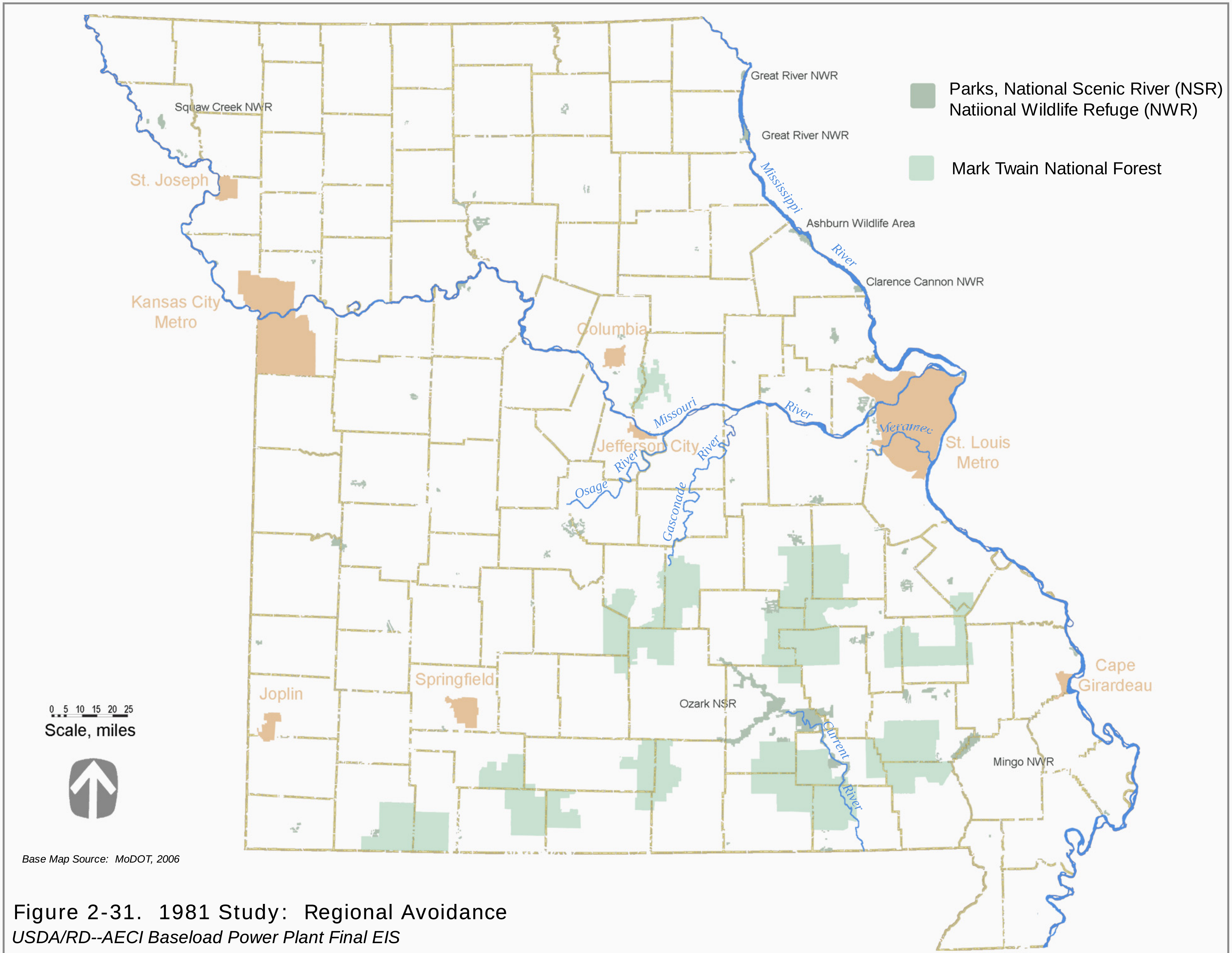

Figure 2-31. 1981 Study: Regional Avoidance

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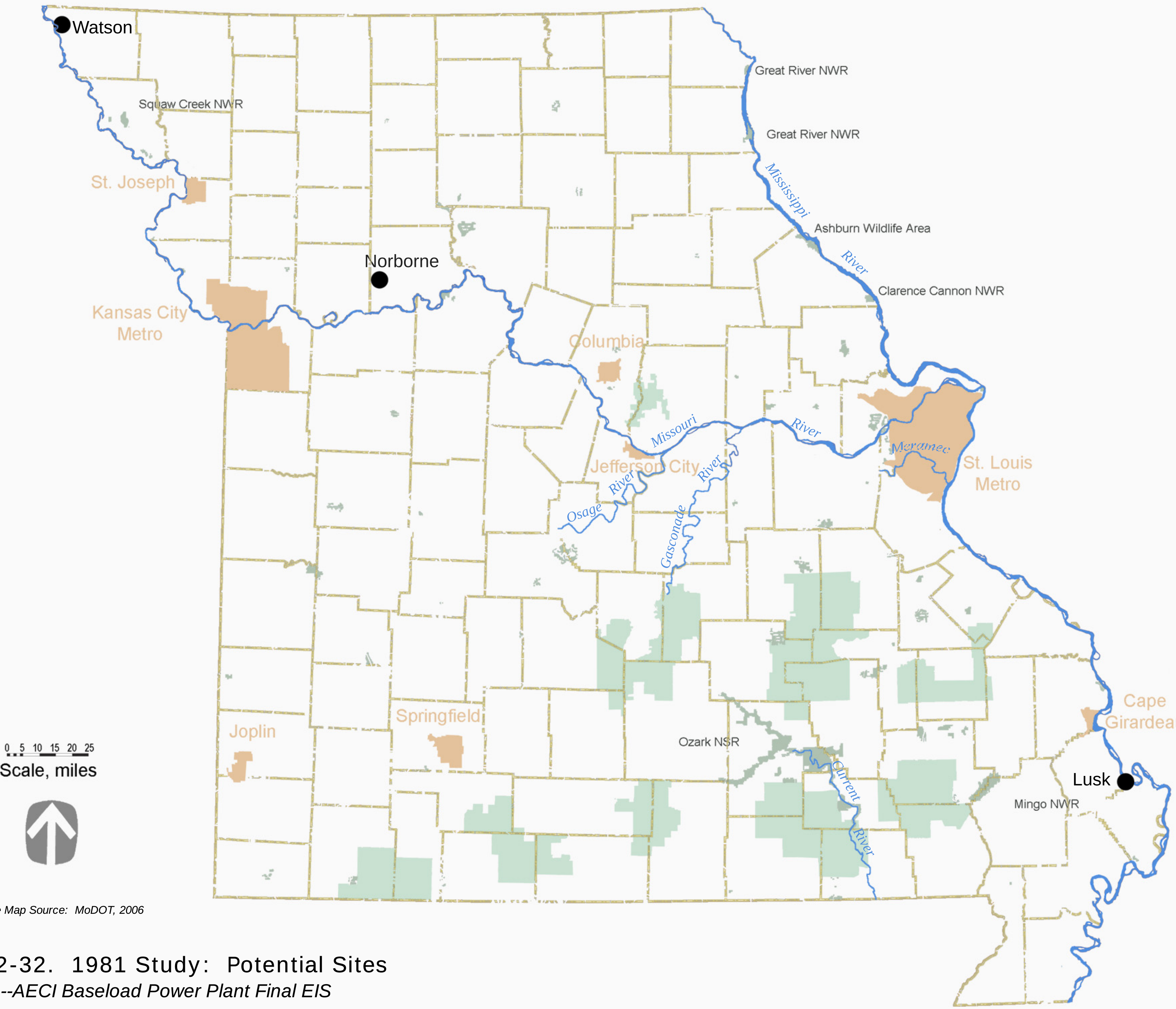

Figure 2-32. 1981 Study: Potential Sites

USDA/RD--AECI Baseload Power Plant Final EIS

2.2.8.2 2003 – 2004 Siting Studies

In 2003, AECI began to seriously re-assess the addition of a coal-based generating unit to meet the growing demand on its system. Many of the same criteria from the 1981 study were still applicable, and that study was used as a starting point. As in the 1981 study, since almost all of AECI's transmission lines (Figure 2-33) and most of its ultimate customers are in Missouri, the first step was to limit the study to the State of Missouri.

The site evaluation criteria used for the 2003 – 2004 study are reproduced as Table 2-8.

2.2.8.2.1 Water Supply

The 1981 water supply analysis was still relevant in 2003. The 10,800 gpm requirement for the 1,200-MW plant was about 35 percent more than the 7,000 gpm needed for the 660 MW net plant[31]. However, it is prudent for AECI to identify a site with additional water capacity, to minimize drought risk and to provide options for future power capacity expansion if needed. Therefore, the 1981 water analysis is still relevant to the current project.

This section includes a more detailed discussion of water availability from reservoirs than was included in the 1981 study; however, the conclusion is the same: the reservoirs are not a practical water source for the proposed facility.

Table 2-3 lists the large reservoirs in and near Missouri. These are all shown in Figure 2-11 except for Rathbun Lake, which is located on the Chariton River in Iowa, off the north edge of the map. All the lakes listed are government-owned except Taneycomo (Empire District Electric Company), Lake of the Ozarks (Ameren) and Thomas Hill (AECI). The Thomas Hill Reservoir is discussed elsewhere in this document. Taneycomo and Lake of the Ozarks are used by investor-owned utilities to generate hydroelectric power, and they are both important recreational lakes. Adding a power plant from another utility to this mix is an impractical option. Of the government-owned reservoirs, all but Grand Lake O' the Cherokees, owned by the state of Oklahoma, are owned by the US government and operated by the USACE.

[31] The original requirement (shown in Table 2-11) was 5,600 gpm. This was later increased to 7,000 gpm.

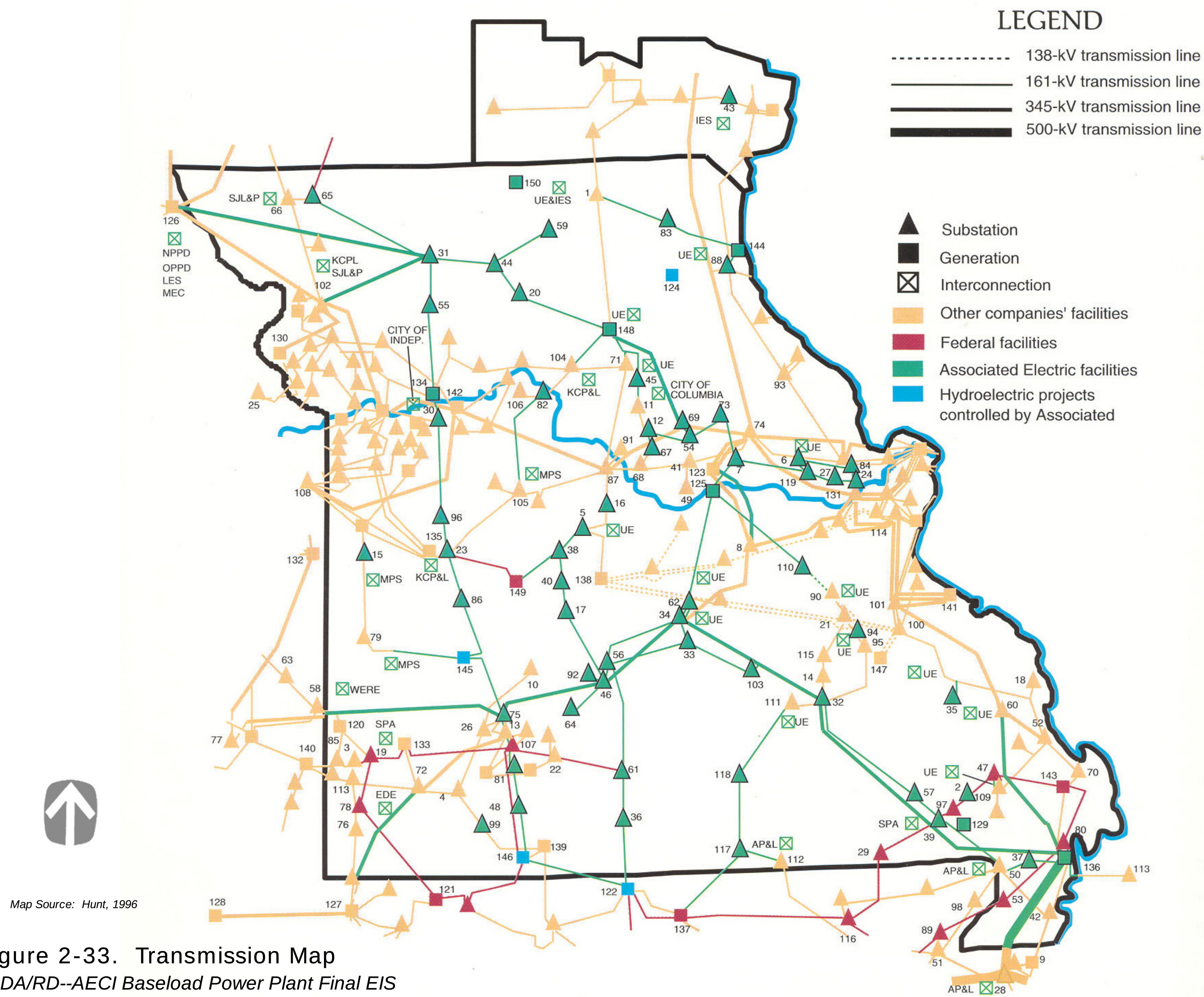

Figure 2-33. Transmission Map

USDA/RD--AECI Baseload Power Plant Final EIS

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
1	Plant Site Topography and Size	Entire site must be at least 1,000 acres. Ground slope across the site, including material storage but excluding solid waste disposal, must not be more than 5% or less than 0.5%.	Minimize amount that site must be raised, in order to minimize costs for earthwork, retaining walls, erosion control, drainage, roadwork, and trackwork.	**8**	Site must be raised 0-3 feet	**5**
					Site must be raised 3-6 feet	**4**
					Site must be raised 6-10 feet	**3**
					Site must be raised 10-15 feet	**2**
					Site must be raised 15-20 feet	**1**
2	Expandability for Future Units	None	Site should have room for expansion with at least one unit beyond base capacity.	**5**	Expandable with two or more additional units	**5**
					Expandable with one additional unit	**3**
					Not expandable	**1**
3	Land Acquisition (evaluated by AECI)	None	Minimize land acquisition difficulty and associated costs.	**7**	Land already owned	**5**
					Moderately difficult land acquisition	**3**
					Highly difficult land acquisition	**1**
4	Distance from Potential Solid Waste Disposal Area	Suitable area must be available on or near plant site to accept all waste for a minimum 50 years of plant operating life.	Minimize distance to potential solid waste disposal areas if not on plant site.	**7**	Suitable disposal area on plant site	**5**
					Suitable disposal area less than 1 mile	**4**
					Suitable disposal area 1 to 2 miles	**3**
					Suitable disposal area 2 to 5 miles	**2**
					Suitable disposal area more than 5 miles	**1**
5	Fill Required for Potential Solid Waste Disposal Area	Dikes around solid waste disposal area must be at least 3 feet above the 100-year flood level (as defined by Corps of Engineers). Bottom of waste must at least 3 feet above the maximum seasonal high ground water table (as defined by County Soil Survey).	Minimize the height of dikes and bottom fill required to satisfy the must criteria. Site will be downgraded if the bottom must be raised more than 3 feet.	**7**	Construct dikes 0-4 feet, raise bottom 0-3 feet	**5**
					Construct dikes 4-8 feet, raise bottom 0-3 feet	**4**
					Construct dikes 8-12 feet, raise bottom 0-3 feet	**3**
					Construct dikes 12-16 feet, raise bottom 0-3 feet	**2**
					Construct dikes 16-20 feet, raise bottom 0-3 feet	**1**
6	Distance from Highway	The site must be within 20 miles of primary or interstate highway.	Locate as close as possible to highway access, in order to:	**5**	Nearest suitable highway less than 1 mile	**5**
			1. Minimize access road construction and maintenance costs.		Nearest suitable highway 1 to 5 miles	**4**
			2. Minimize travel required for workforce and for material delivery.		Nearest suitable highway 5 to 10 miles	**3**
			3. Minimize permit requirements and potential public opposition.		Nearest suitable highway 10 to 15 miles	**2**
					Nearest suitable highway 15 to 20 miles	**1**

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
7	Distance from Primary Railroad Connection	The site must be within 20 miles of an existing rail connection point.	Locate as close as possible to primary rail connection, in order to:	7	Nearest suitable railroad connection less than 1 mile	5
			1. Minimize rail spur construction and maintenance costs.		Nearest suitable railroad connection 1 to 5 miles	4
			2. Minimize freight rates for fuel and reagent transportation.		Nearest suitable railroad connection 5 to 10 miles	3
			3. Minimize permit requirements and potential public opposition.		Nearest suitable railroad connection 10 to 15 miles	2
					Nearest suitable railroad connection 15 to 20 miles	1
8	Potential Rail Spur Grade	Compensated grade of rail spur to primary rail connection must not exceed 2% at any point	Minimize rail spur grade to primary rail connection, in order to reduce transportation, construction and maintenance costs.	7	Grade less than 0.50 percent	5
					Grade 0.50 to 0.75 percent	4
					Grade 0.75 to 1.00 percent	3
					Grade 1.00 to 1.50 percent	2
					Grade 1.50 to 2.00 percent	1
9	Potential Rail Spur Corridors	None	More than one potential corridor that is favorable for both environmental and engineering factors should be available from site to primary connection point.	8	Two or more favorable corridors available	5
					One favorable corridor available	4
					Two or more marginal corridors available	3
					One marginal corridor available	2
					Only unfavorable corridors available	1
10	Alternate Coal and Reagent Transportation	None	To increase competition and lower coal and reagent transportation costs, locate site such that it is accessible to two different rail carriers having independent access to the Powder River Basin.	10	Two rail alternatives connecting to main tracks	5
					One rail alternative connecting to main track and one connecting to secondary track	3
					One rail alternative	1
11	Distance from Secondary Railroad Connection	None	Locate as close as possible to secondary rail connection. Site will be downgraded if a major river must be crossed or if the rail spur grade would be more than 0.8 percent.	5	Secondary connection less than 1 mile	5
					Secondary connection 1 to 5 miles	4
					Secondary connection 5 to 12 miles	3
					Secondary connection 12 to 20 miles	2
					Secondary connection more than 20 miles	1

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
12	Distance from Coal Supply	None	Minimize the distance between coal supply and the site, in order to lower operational costs.	7	Mine mouth site	5
					Site within 50 miles of coal supply	4
					Site 50 to 100 miles from coal supply	3
					Site 100 to 200 miles from coal supply	2
					Site greater than 200 miles from coal supply	1
13	Flood Potential	The entire plant site must be above the 100 year flood level or must be feasible to protect from the 100 year flood.	Locate the entire site above the 100 year flood level to eliminate potential down time and loss of equipment in the event of a flood. Power block area lower than the 100 year flood level must be raised. If the site is in a flood plain, locate behind a federal levee if possible.	5	Entire site above 100 year flood level	5
					Site behind a federal levee designed for the 100 year flood level	3
					Site not behind a federal levee designed for the 100 year flood level	1
14	Foundation, Earthwork and Pipe Installation Conditions	There must be no sinkhole or mine subsidence activity. There must be no deep deposits of loose, soft or highly expansive material. Solid rock must not be closer than 3 feet from the surface.	For foundations, it is desirable to have dense granular soils or rock 5 to 10 feet below the surface. Less desirable, based on strength, settlement and construction costs are permeable soils. Silt is even less desirable because of low strength and erodibility. Rock close to the surface raises construction costs for earthwork and pipes.	5	Mostly granular soil	5
15	Groundwater Construction Impact	None	Depth to normal groundwater should be at least 20 feet below grade, to avoid impacts on the cost of foundations and earthwork and to facilitate permitting of solid waste disposal facilities.	3	Depth to groundwater more than 20 feet	5
					Depth to groundwater 10 to 20 feet	3
					Depth to groundwater less than 10 feet	1
16	Geological / Seismic Activity	None	Locate site in area of least restrictive seismic design category (per International Building Code 2000).	5	Seismic design category A	5
					Seismic design category B	4
					Seismic design category C	3
					Seismic design category D	2
					Seismic design category E	1
17	Infrastructure (Utilities)	None	Locate site in an area with highly developed infrastructure (water supply, sewers, etc.).	7	Highly developed existing infrastructure	5
					Moderately developed existing infrastructure	4
					Limited developed existing infrastructure	3
					Slightly developed existing infrastructure	2
					No developed existing infrastructure	1

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
18	Distance from Transmission Connection	The site must be accessible to a suitable transmission line or substation connection point.	Minimize the total distance between the transmission connections and the plant, in order to lower operation and construction costs and minimize public opposition.	**7**	Total transmission distance less than 50 miles	**5**
					Total transmission distance 50 to 100 miles	**4**
					Total transmission distance 100 to 150 miles	**3**
					Total transmission distance 150 to 200 miles	**2**
					Total transmission distance more than 200 miles	**1**
19	Potential Transmission Line Corridors	None	More than one potential corridor that is favorable for both environmental and engineering factors should be available from site to nearest transmission connection point.	**8**	Two or more favorable corridors available	**5**
					One favorable corridor available	**4**
					Two or more marginal corridors available	**3**
					One marginal corridor available	**2**
					Only unfavorable corridors available	**1**
20	Transmission System Stability (evaluated by AECI)	None	Minimize risk of transmission system stability problems.	**5**	Low stability risk	**5**
					Medium stability risk	**3**
					High stability risk	**1**
21	Distance from Adequate Source of Cooling Water	The site must be within 20 miles of an adequate cooling water source.	Minimize the distance between the water source and the plant, in order to lower operational and construction costs.	**7**	Site less than 1 mile from water source	**5**
					Site 1 to 5 miles from water source	**4**
					Site 5 to 10 miles from water source	**3**
					Site 10 to 15 miles from water source	**2**
					Site 15 to 20 miles from water source	**1**
22	Adequacy of Cooling Water Source	Water source must be capable of supplying 5,600 gpm under low flow conditions. No make-up storage reservoir required.	Minimize the percentage of the 7 day, 10 year low flow (7Q10) withdrawn.	**7**	5,600 gpm is less than 1 percent of 7Q10	**5**
					5,600 gpm is 1 to 2 percent of 7Q10	**4**
					5,600 gpm is 2 to 5 percent of 7Q10	**3**
					5,600 gpm is 5 to 10 percent of 7Q10	**2**
					5,600 gpm is more than 10 percent of 7Q10	**1**

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
23	Cooling Water Static Head Requirements	None	Minimize the pumping head, in order to reduce operating costs.	5	Less than 100 feet	5
					From 100 to 200 feet	4
					From 200 to 300 feet	3
					From 300 to 400 feet	2
					Greater than 400 feet	1
24	Class I Areas	The site must not be located in or closer than 100 miles to a Class I Area.	Locate site as far as possible from Class I Areas, in order to minimize permitting costs and potential public opposition.	8	Site more than 200 miles from all Class I Areas	5
					Site within 200 miles of one Class I Area	4
					Site within 200 miles of two or more Class I Areas	3
					Site within 150 miles of one Class I Area	2
					Site within 150 miles of two or more Class I Areas	1
25	Designated Parks and Preserves	The site must not be located in a federal, state, or local designated park or preserve.	Locate site as far as possible from federal, state, and local designated parks and preserves.	7	Nearest designated area more than 20 miles from site	5
					Nearest designated area 10 to 20 miles from site	4
					Nearest designated area 5 to 10 miles from site	3
					Nearest designated area 1 to 5 miles from site	2
					Nearest designated area less than 1 mile from site	1
26	Land Planning / Zoning	None	Locate site in area of compatible land planning / zoning.	7	Highly compatible planning / zoning (e.g., heavy industry)	5
					Moderately compatible planning / zoning (e.g., light industry / commercial)	4
					Slightly compatible planning / zoning (e.g., agricultural / forestry)	2
					Incompatible planning / zoning (e.g., residential / recreational)	1
27	Existing Land Use on the Site	None	Locate site where existing predominant on-site land use is compatible with power plant development.	10	Highly compatible (unused "brownfield" land)	5
					Moderately compatible (mineral extraction)	4
					Slightly compatible (agriculture or forestry)	3
					Somewhat incompatible (active industrial/commercial development)	2
					Highly incompatible (recreational, institutional or residential development)	1

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
28	Existing Residences on the Site	None	Minimize number of residences displaced.	10	No residences displaced	5
					One (1) residence displaced	4
					2 to 4 residences displaced	3
					5 to 10 residences displaced	2
					More than 10 residences displaced	1
29	Nearby Existing Land Use	None	Locate site where existing predominant land use (other than industrial/commercial development) within one mile is compatible with power plant.	8	Highly compatible ("brownfield" or mineral extraction)	5
					Somewhat compatible (agriculture or forestry)	3
					Incompatible (recreational, institutional or residential development)	1
30	Potential Contamination	The site must not be a known contaminated or designated Superfund property.	Locate site in an area free of potential hazardous material contamination.	7	No contamination potential	5
					Low contamination potential	4
					Medium contamination potential	2
					High contamination potential	1
31	Archaeological and Historical Resources	None	Locate site so as to avoid potential historical or archeological resources.	7	No cultural resources (site previously investigated)	5
					Site previously disturbed (graded, plowed, developed)	4
					Site not previously disturbed, low potential	3
					Site not previously disturbed, high potential	2
					Known cultural resources	1
32	Cemeteries	Site development must not disturb or otherwise impact cemeteries.	No cemeteries should be on the site or nearby.	5	None within 1,000 feet of site	5
					None on-site	3
					One or more onsite (but avoidable)	1
33	Scenic Areas	None	Site should be minimally visible from designated scenic areas (parks, nature preserves, historical sites, etc.).	7	Site not visible from any designated area	5
					Moderately visible from one designated area	4
					Moderately visible from two or more designated areas	3
					Highly visible from one designated area	2
					Highly visible from two or more designated areas	1

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
34	Noise Impacts	None	Minimize potential impacts on sensitive receptors (homes, hospitals, churches, schools, recreation areas, etc.).	**7**	No sensitive receptors within 1/2 mile of existing facility	**5**
					No sensitive receptors within 1/2 mile of greenfield site	**4**
					Less than 10 sensitive receptors within 1/2 mile of existing facility	**3**
					Less than 10 sensitive receptors within 1/2 mile of greenfield site	**2**
					More than 10 sensitive receptors within 1/2 mile of any site	**1**
35	Prime Farmland	None	Site should occupy minimum prime farmland.	**5**	No prime farmland occupies site	**5**
					Prime farmland occupies 1 to 25 percent of site	**4**
					Prime farmland occupies 26 to 50 percent of site	**3**
					Prime farmland occupies 51 to 75 percent of site	**2**
					Prime farmland occupies 76 to 100 percent of site	**1**
36	Dispersion Conditions	None	Locate where terrain and structures within approximately 10 to 15 kilometers of the site do not interfere with dispersion of stack plume.	**7**	Minimal interference possible	**5**
					Some interference possible	**3**
					Significant interference possible	**1**
37	Background Air Quality	None	Locate where existing background pollutant concentrations, PSD increments, and/or nearby emission sources do not interfere with air permitting.	**8**	SCORING CRITERIA TO BE DEVELOPED BASED ON AVAILABLE DATA	**5**
						3
						1
38	Air Quality Non-Attainment Areas	None	Locate as far as possible from non-attainment areas, in order to minimize permitting costs and potential public opposition.	**7**	Nearest non-attainment area more than 60 miles	**5**
					Nearest non-attainment area 40 to 60 miles	**4**
					Nearest non-attainment area 20 to 40 miles	**3**
					Nearest non-attainment area 10 to 20 miles	**2**
					Nearest non-attainment area less than 10 miles	**1**
39	Multiple State Involvement in Permitting	None	Locate site more than 50 miles from state border to avoid air permit review by another state.	**3**	Nearest state border more than 50 miles	**5**
					Nearest state border less than 50 miles	**1**

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
40	Fogging and Icing Impact Potential	None	Locate cooling towers more than 1,000 feet from any roads or other features sensitive to ice or fog.	7	Nearest sensitive feature more than 1,000 feet	5
					Nearest sensitive feature 600 to 1,000 feet	4
					Nearest sensitive feature 300 to 600 feet	3
					Nearest sensitive feature 100 to 300 feet	2
					Nearest sensitive feature less than 100 feet	1
41	Proximity to Airports / Airstrips	None	Locate site as far as possible from public and private airports and airstrips registered with the Department of Transportation.	5	Distance to nearest registered airport/airstrip is: more than 25,000 feet	5
					20,000 to 25,000 feet	4
					10,000 to 20,000 feet	3
					3,500 to 10,000 feet	2
					Less than 3,500 feet	1
42	Wetlands Impact Potential	None	Minimize the acreage of jurisdictional wetlands potentially affected by site development.	10	No wetlands affected	5
					Less than 1 acre of wetlands affected	4
					1 to 5 acres of wetlands affected	3
					5 to 10 acres of wetlands affected	2
					More than 10 acres of wetlands affected	1
43	Other Natural Habitats Impact Potential	None	Minimize potential impact on natural habitats other than wetlands.	7	No natural habitats on-site	5
					Less than 25 percent natural habitats	4
					25 to 50 percent natural habitats	3
					50 to 75 percent natural habitats	2
					75 to 100 percent natural habitats	1
44	Documented Occurrence of Threatened and Endangered Species	No designated critical habitat of a federal or state threatened or endangered species onsite.	Locate site as far as possible from recent documented occurrence of threatened or endangered species.	7	Nearest documented occurrence more than 5 miles from site	5
					Nearest documented occurrence 1 to 5 miles from site	4
					Nearest documented occurrence 1/2 to 1 mile from site	3
					Nearest documented occurrence less than 1/2 mile from site	2
					Nearest documented occurrence onsite	1

Table 2-8. AECI Site Evaluation Criteria - Revision 2

Item No.	Description of Characteristic	Musts	Wants	Numerical Weighting Factor - Importance (10 is High, 1 is Low)	Evaluation Criteria	Numerical Rating Factor (5 is Best, 1 is Worst)
45	Surface Water Impact Potential	Site must not impact Wild or Scenic River.	Minimize potential conflict between power plant operations and use designation of receiving water.	**7**	Limited forage fish / aquatic life	**5**
					Warm water community (sport or forage fish)	**4**
					Warm water community tributary to Great Lakes	**3**
					Cold water community	**2**
					Great Lakes community	**1**
46	Ground Water Impact Potential	None	Minimize potential for contamination of aquifers used for potable water.	**7**	SCORING CRITERIA TO BE DEVELOPED BASED ON AVAILABLE DATA	**5**
						3
						1
47	Nearby Towns	None	Locate site as far as possible from populated towns, in order to minimize negative public reaction.	**8**	Nearest town more than 10 miles from site	**5**
					Nearest town 5 to 10 miles from site	**4**
					Nearest town 3 to 5 miles from site	**3**
					Nearest town 1 to 3 miles from site	**2**
					Nearest town less than 1 mile from site	**1**

Grand Lake O' the Cherokees can be used for water supply, but the enabling legislation restricts sales of water to Oklahoma. Many of the USACE reservoirs are used for water supply, though nearly all were originally created for the primary purpose of flood control. The Water Supply Act of 1958 authorizes the Secretary of Defense (through the USACE) to "make contracts with states, municipalities, private concerns, or individuals, at such prices and on such terms as he may deem reasonable, for domestic and industrial uses for surplus water that may be available at any reservoir under the control of the Department of the Army: Provided, that no contracts for such water shall adversely affect the existing lawful uses of such water."[32] Therefore, surplus water can be used for water supply, but the original authorized uses of the reservoirs take precedent. The USACE must balance competing uses, including flood control, hydroelectric power production, fish and wildlife, water supply, and recreation. The process of determining a price and negotiating a contract is lengthy and requires USACE headquarters approval (USACE, 2005c). And the surplus water is in demand and it is unlikely AECI would get a firm allocation for power production. Of the USACE reservoirs within and near Missouri, only Clearwater, Wappapello, and Pomme de Terre are not used for water supply. All the White River reservoirs along the Missouri-Arkansas border (Beaver, Table Rock, Bull Shoals and Norfork) are used for water supply. Based on the Water Supply Act of 1958, the USACE can re-allocate no more than 50,000 acre-ft from each reservoir for water supply. In November 2005 there were 10 water supply requests pending for reallocation of storage in the White River basin lakes (USACE, 2005c). Mark Twain Lake, in northeast Missouri, is a major water supply source serving several counties, through the Clarence Cannon Wholesale Water Commission. Surplus water supply in the Kansas City District USACE reservoirs is fully contracted to state agencies, municipalities, and rural water districts (USACE, 2005a).

In summary, many of the government-owned large reservoirs in Missouri are used for water supply, but most of the available water is already contracted to other parties, and for any water that may be available, long lead times and high-level US government approval is needed to get a contract in place. Both the non-AECI privately held reservoirs are used for hydroelectric generation and both are important recreational lakes. It is unlikely that excess water in the amount needed would be available from either, and in any case, because of their current recreational uses, neither location is suitable for construction of a new power plant.

[32] 33 USC 708

2.2.8.2.2 Regional Avoidance Criteria

Updated regional avoidance criteria are shown in Figure 2-34. The public lands and urban areas identified for avoidance in the 1981 report were still applicable. In addition, the Metropolitan Kansas City and St. Louis were included for avoidance in the 2003 – 2004 study. The St. Louis area (including the City of St. Louis, St. Louis County, Jefferson County, Franklin County, and St. Charles County) was expected to be found to not meet the National Ambient Air Quality Standard (NAAQS) for ozone and particulates. The Kansas City area was attaining NAAQS but in the case of ozone by only a small margin. Therefore each of these areas presented potential air quality issues for any proposed new power plant.

The Clean Air Act (CAA) Amendments of 1977 resulted in establishment of the Prevention of Significant Deterioration (PSD) regulations. Under these regulations, maximum pollutant concentration increases (increments) were established for each criteria pollutant. These allowable increments are most restrictive for areas designated “Class I”. Class I areas include national parks, wilderness areas, monuments, and other areas of special national or cultural significance. Typically, air quality modeling must consider impacts of a proposed source on a Class I area about 100 miles or less from the source (AECI, 2005a), but greater distances may be used for larger sources. There are two Class I areas in Missouri, both shown on Figure 2-34: Hercules Glades Wilderness Area in Mark Twain National Forest, and Mingo National Wilderness Area. There is only one Class I area outside Missouri that lies within 100 miles of Missouri’s borders: the Buffalo River Class I Area in Arkansas, south of Hercules Glades, (NPS, 2006). AECI established 100 miles as the minimum distance from a Class I area (Table 2-8). As shown in Table 2-8, AECI considered sites more favorable if they were 150 miles or more from Class I areas, and most favorable at a distance of 200 miles or more.

The avoidance area based on the 100-mile radius from a Class I area, plus the avoidance areas based on non-attainment are shown in Figure 2-34, along with the previous avoidance areas. These avoidance criteria eliminate nearly half the state from consideration.

Note that the Class I avoidance criterion eliminates Lusk, one of the 1981 sites. While the PSD program began prior to the 1981 siting study, the air quality impact evaluation on Class I areas has become more rigorous as air

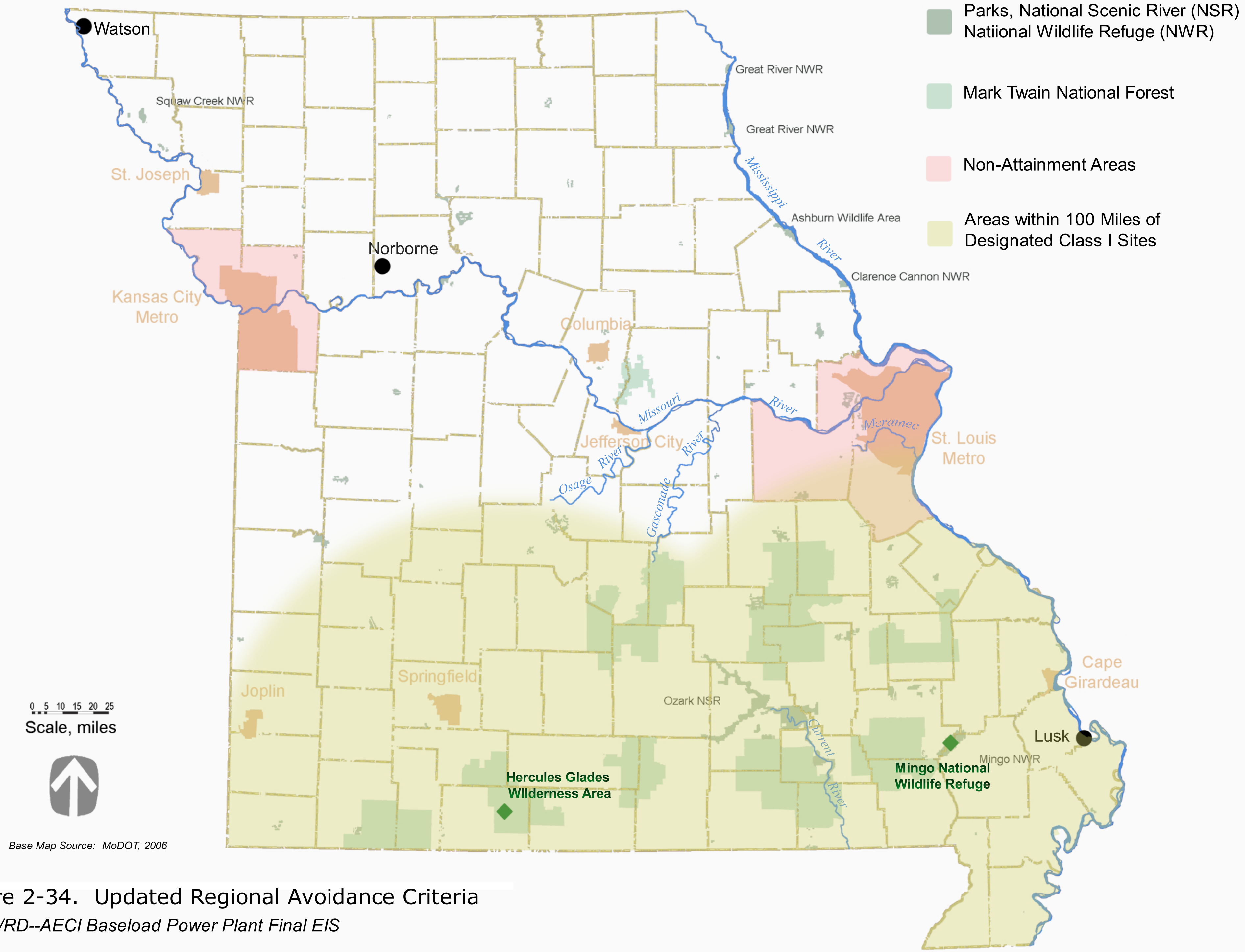

Figure 2-34. Updated Regional Avoidance Criteria

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quality models have improved. In 1981 the distance between a proposed new source and a Class I area that would dictate a modeling analysis was considerably less than 100 miles, whereas today it is even more.

2.2.8.2.3 Coal Availability

Since the mid-1990s, AECI has made major investments to reduce sulfur dioxide emissions. This included $200 million to convert its coal units to burn 100 percent low-sulfur coal and $342 million to close its high-sulfur coal mine in Missouri. As a result, AECI's system-wide sulfur dioxide emission rate has been reduced by 90 percent (AECI, 2006e). To continue to keep sulfur emission rates low, AECI plans to continue to burn only low-sulfur coal.

Therefore, for the 2003 – 2004 study high-sulfur Illinois and Missouri coal were no longer considered potential fuel sources for a new plant; only the cleaner-burning PRB coal was considered.

Only two carriers originate coal deliveries from the PRB to Missouri: Burlington Northern Santa Fe (BNSF) and Union Pacific (UP). Their lines are shown in Figure 2-35. AECI's two baseload plants, Thomas Hill and New Madrid, are also shown in the figure.

Since coal transportation is a large part of the operating cost of a coal-fired plant, hauling distance from the PRB was an important criterion in the siting process. Figure 2-36 shows the relationship of the PRB to the state of Missouri.

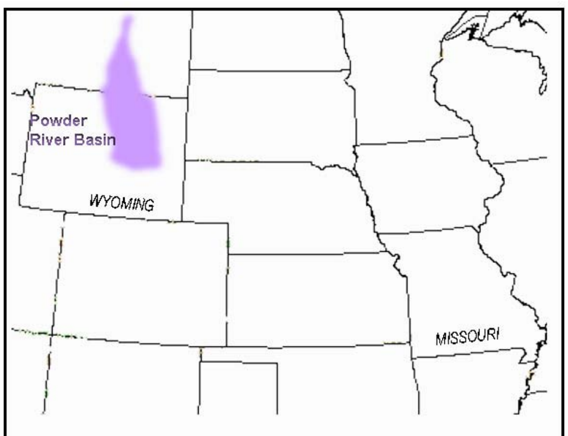

Figure 2-36. Location of the PRB

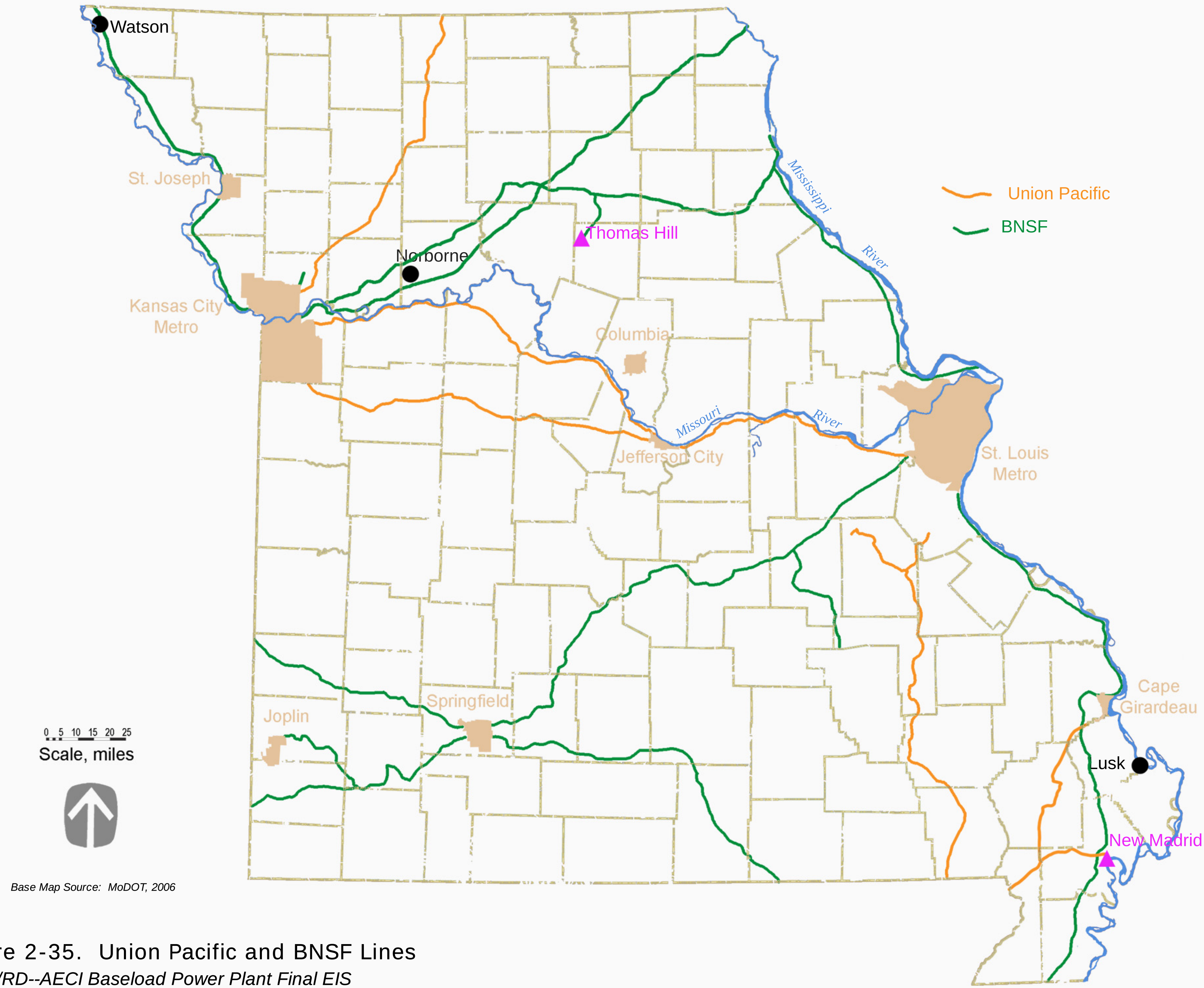

Figure 2-35. Union Pacific and BNSF Lines

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Figure 2-37 shows the general area of the state within the most desirable radius of the PRB for siting a new plant. This area is also favorable in terms of avoidance criteria. Note that the coal-haul distance criterion also disfavors the Lusk site. In the 1981 study, the Lusk site was to be supplied by Illinois coal from Mississippi River barges.

Since AECI's existing coal-fired Thomas Hill facility, the Watson site, and the Norborne site from the 1981 study are all in this area, they were considered in the assessment. However, the 1981 Norborne site was an upland site some distance from the Missouri River. Rather than assessing the upland site, which would have been much costlier to develop, other sites in the general area, referred to as the "Norborne Area," but closer to the river, were identified. This required balancing the cost and the potential floodplain impacts.

2.2.8.2.4 Identification of Sites

In the siting search, AECI established 20 miles as the maximum practical distances from an existing rail connection point, and from a surface water source capable of supplying 5,500 gpm under low flow conditions (Table 2-8, AECI, 2004a). Of course, to avoid impacting the stream, the stream flow needs to be substantially greater than AECI's needs. The actual minimum criterion was that the required 5,500 gpm had to be less than 10 percent of the 7Q10 flow (i.e., the 7Q10 flow had to be greater than 55,000 gpm = 122 cfs). The estimated plant need was later increased to 7,400 gpm.

Aside from the Mississippi, the Missouri, and the rivers previously discussed under the 1981 study, there are no streams in the northern half of Missouri that meet the flow criteria. After the Missouri River, the largest stream in the highlighted area shown in Figure 2-37 is the Grand River, a Missouri River tributary. Its 7Q10 flow, determined at a location near Swan Lake NWR, downstream of all its major tributaries, is 17,000 gpm, well below the 55,000 gpm criterion for 7Q10 flow for the needed water source (MDNR, 1997).

The part of northwest Missouri that meets the minimum acceptable rail and water source distances is shown highlighted in blue in Figure 2-38.

Figure 2-39 shows the same blue-highlighted area, but now reduced by including the avoidance areas previously discussed: urban areas, public lands, and the non-attainment Kansas City metropolitan area. As shown, there are

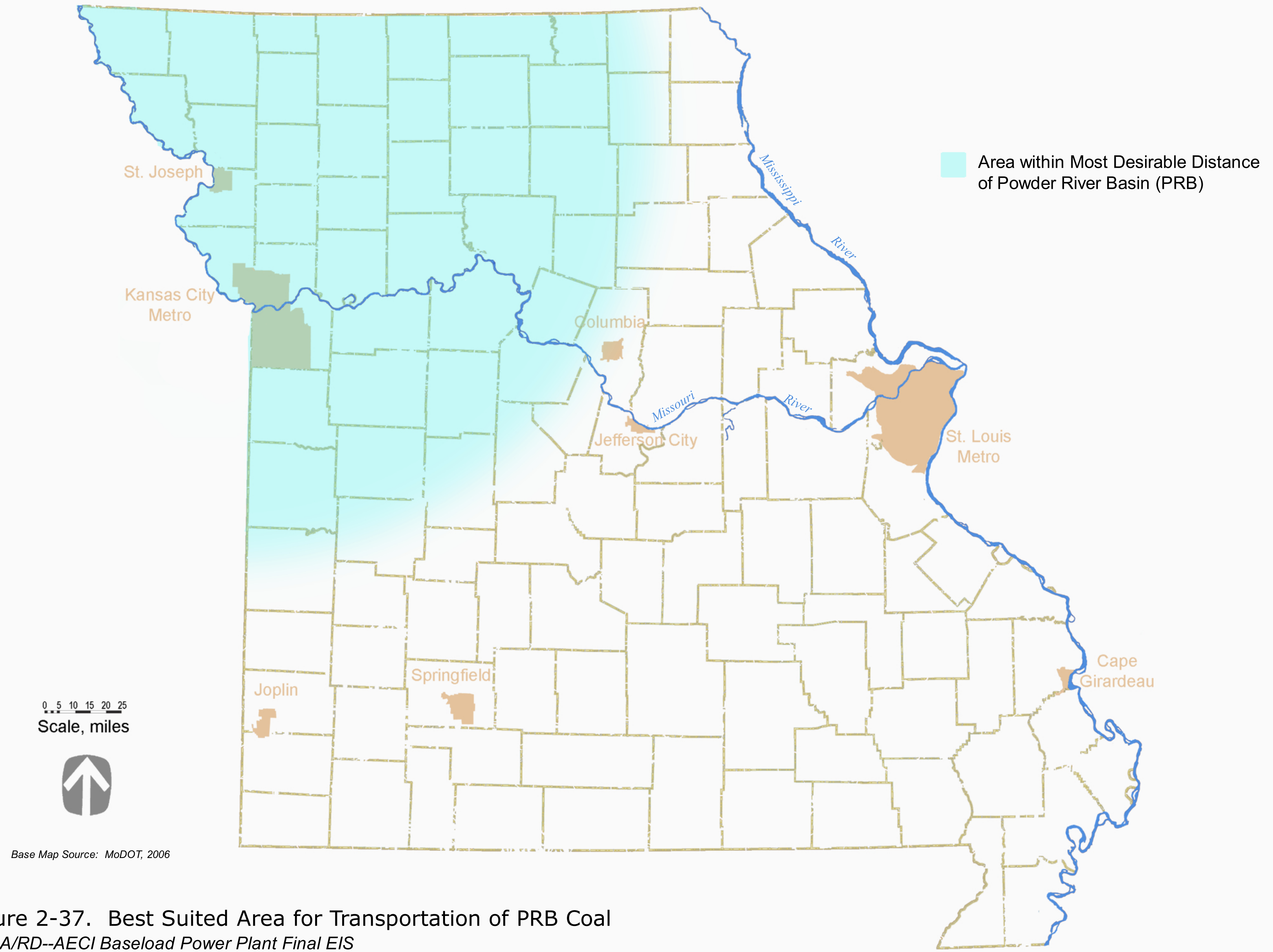

Figure 2-37. Best Suited Area for Transportation of PRB Coal

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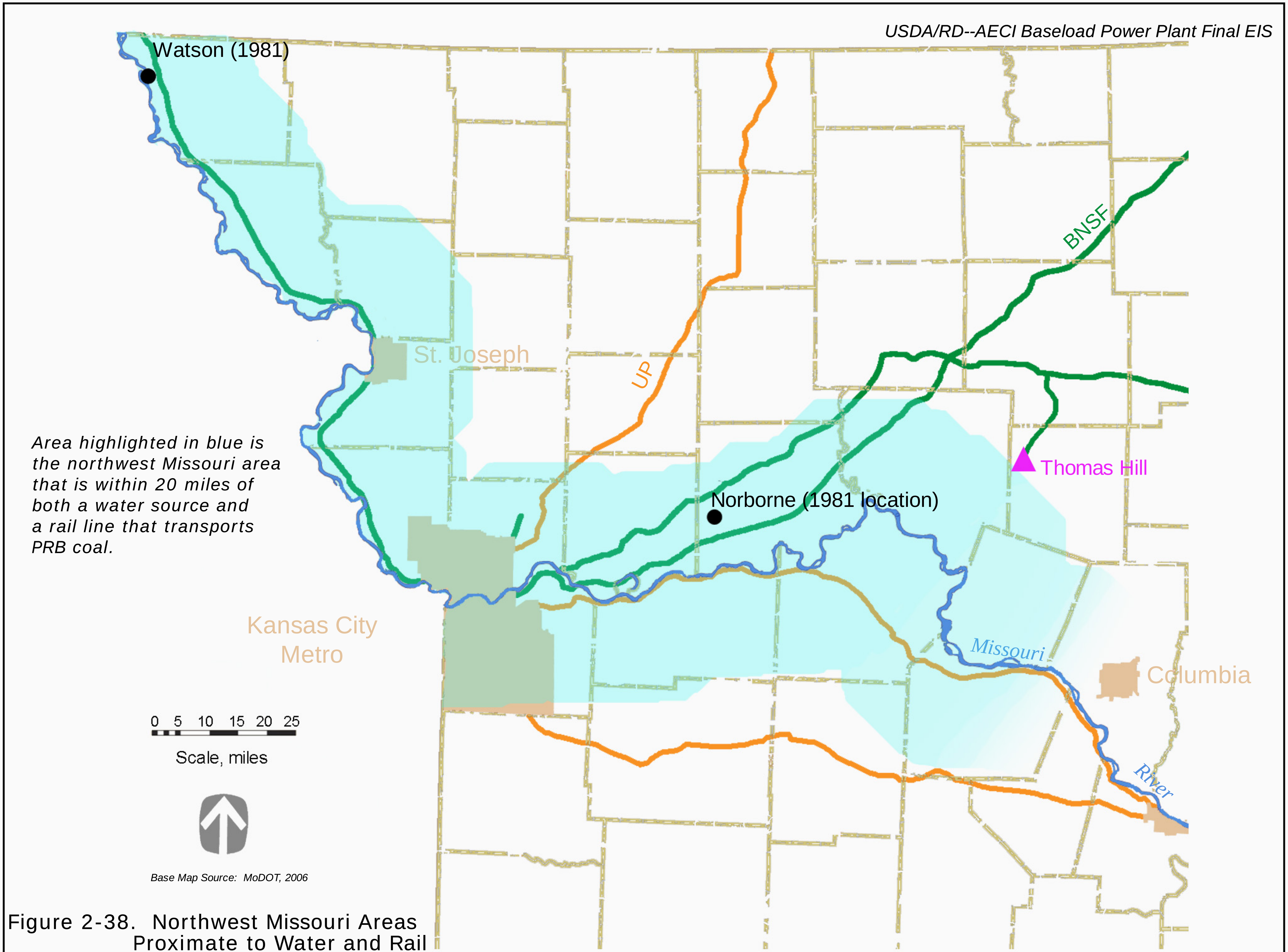


Figure 2-38. Northwest Missouri Areas Proximate to Water and Rail

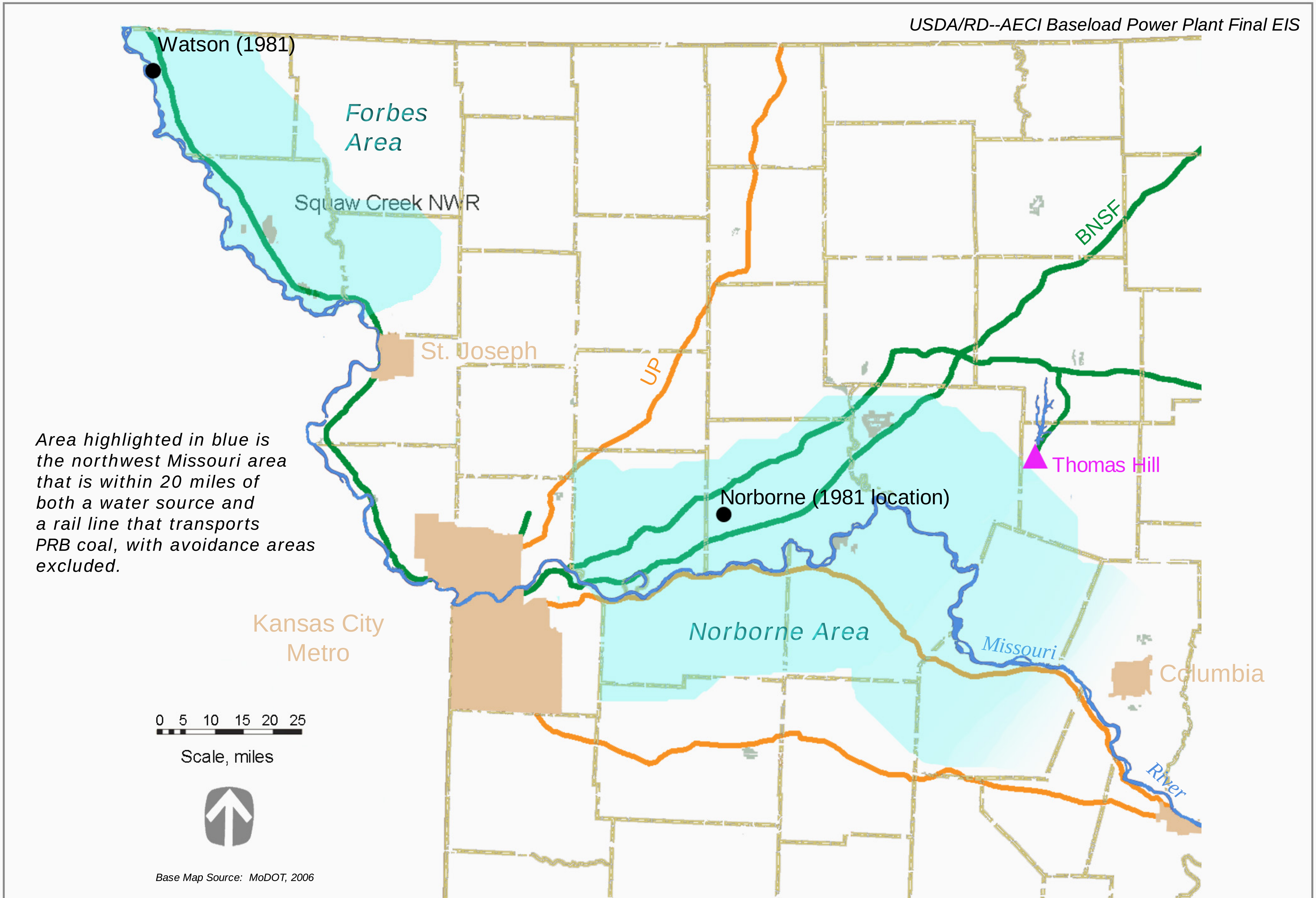


Figure 2-39. Northwest Missouri--Water and Rail, with Avoidance Areas Excluded

essentially two general siting areas: one along the Missouri River north of the Kansas City area (Forbes Area), and one along the Missouri River east of the Kansas City area (Norborne Area). Note that the 1981 sites Watson and Norborne are within these areas. AECI's Thomas Hill Energy Center, located at the edge of the siting area, has its own water supply and rail access and was included as a potential site.

In 2004, AECI identified and evaluated eight potential new sites within these two areas: two in the Forbes Area (West and East Forbes), and six in the Norborne Area (West Carrollton, East Ray, West Oxbow, Southwest Norborne, East Oxbow, and South Hardin). Site locations are shown in Figure 2-40. These sites are not spread throughout the refined siting area, but are concentrated at locations that are both near the railroads and the water supply source. If suitable sites are available very close to existing rail lines and water sources, that eliminates the need to look at more distant sites. The sites were evaluated based on the criteria included in Table 2-8. The results are detailed in Table 2-9 and summarized in Table 2-10. As shown in Table 2-10 there was little difference in the ratings among the sites (less than 10% difference between the highest and lowest rated sites). A comparison between the highest-rated site (West Forbes) and the lowest-rated site (South Hardin) shows that the items most responsible for the higher West Forbes rating were the smaller amount of fill required to raise the site above the 100-year floodplain, the greater distance to public lands, and the greater distance to a park. AECI concluded that any of these sites could potentially be suitable for the plant and began an iterative process of comparison of siting costs, beginning with Watson, Thomas Hill, a generic site representing the Forbes Area, and a generic site representing the Norborne Area. A cost comparison from October 2004 is shown as Table 2-11. As shown in the table, the generic Forbes Area site had the lowest site-related costs, and the generic Norborne Area site the highest, at approximately 36 percent higher. However, a substantial portion of that difference was due to a $100,000,000 Chapter 100 financing penalty for Norborne, since it was uncertain whether Carroll County would provide a Chapter 100 proposal. Ultimately, Carroll County provided the most competitive proposal.

Between October and December 2004, as more site-specific information was developed, AECI made decisions that resulted in the elimination of several sites, and the addition of a new site in the Forbes Area, and a new site in the Norborne Area. These developments are discussed below.

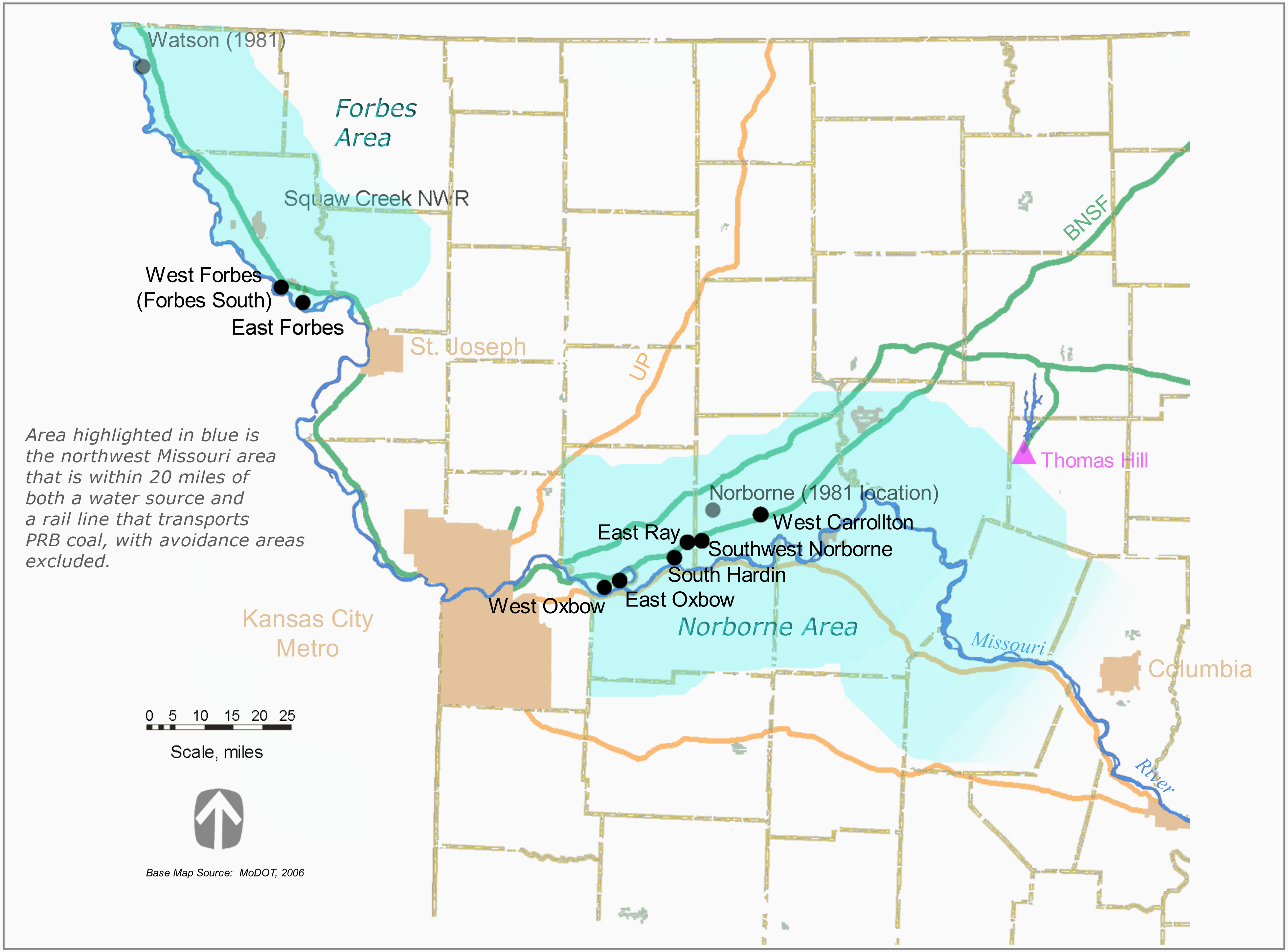


Figure 2-40. Eight Initial Sites 2004

Table 2-9. AECI Site Rating Summary - Revision 2

Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	East Forbes (Holt County)				West Forbes (Holt County)				West Carrollton (Carroll County)			
			Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information
1	Plant Site Topography and Size	**8**	**1**	**8**	Site needs to be raised approximately 16' to be above 100-year flood.	Topographic Map	**2**	**16**	Site needs to be raised approximately 11' to be above 100-year flood.	Topographic Map	**3**	**24**	Site needs to be raised approximately 6' to be above 100-year flood.	Topographic Map
2	Expandability for Future Units	**5**		**0**				**0**				**0**		
3	Land Acquisition (evaluated by AECI)	**7**		**0**				**0**				**0**		
4	Distance from Potential Solid Waste Disposal Area	**7**	**5**	**35**	Suitable disposal area on site.	Topographic Map	**5**	**35**	Suitable disposal area on site.	Topographic Map	**5**	**35**	Suitable disposal area on site.	Topographic Map
5	Fill Required for Potential Solid Waste Disposal Area	**7**		**0**				**0**				**0**		
6	Distance from Highway	**5**	**2**	**10**	8 miles to Forest City (Rte 111 and 11 miles to Oregon (Rte 59)	Road Maps	**3**	**15**	3 miles to Forest City (Rte 111 and 6 miles to Oregon (Rte 59)	Road Maps	**5**	**25**	Less than 1 mile to Rte 10.	Topographic Map
7	Distance from Primary Railroad Connection	**7**	**5**	**35**	Approximately 1 miles to BNSF	Topographic Map	**5**	**35**	Approximately 1 miles to BNSF	Topographic Map	**4**	**28**	Approximately 1 mile to BNSF	Topographic Map
8	Potential Rail Spur Grade	**7**		**0**				**0**				**0**		
9	Potential Rail Spur Corridors	**8**		**0**				**0**				**0**		
10	Alternate Coal and Reagent Transportation	**10**	**5**	**50**	Nearest alternate rail line (UP) is across Missouri River about 9 miles away. Need major river crossing.	Topographic Map	**5**	**50**	Nearest alternate rail line (UP) is across Missouri River about 12 miles away. Need major river crossing.	Topographic Map	**5**	**50**	Potential connection to NS is possible but connection point is 28 miles west. Potential connection to UP is 8 miles south but a bridge across the Missouri river is required	Topographic Map
11	Distance from Secondary Railroad Connection	**5**	**1**	**5**	Nearest alternate rail line is across Missouri River about9 miles away. Need major river crossing.	Topographic Map	**1**	**5**	Nearest alternate rail line (UP) is across Missouri River about 12 miles away. Need major river crossing	Topographic Map	**1**	**5**	NS is 28 miles west of the site.	Topographic Map
12	Distance from Coal Supply	**7**		**0**				**0**				**0**		
13	Flood Potential	**5**	**3**	**15**	Federal Levee Unit 488L at 100-year flood elevation.	Topographic Map	**3**	**15**	Federal Levee Unit 488I at 100-year flood elevation.	Topographic Map	**1**	**5**	Site in 100-year flood plain and not behind Federal Levee.	Topographic Map

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-9. AECI Site Rating Summary - Revision 2

Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	East Forbes (Holt County) Numerical Rating (5 is Best - 1 is Worst)	East Forbes Product	East Forbes Reason for Rating	East Forbes Source of Information	West Forbes (Holt County) Numerical Rating (5 is Best - 1 is Worst)	West Forbes Product	West Forbes Reason for Rating	West Forbes Source of Information	West Carrollton (Carroll County) Numerical Rating (5 is Best - 1 is Worst)	West Carrollton Product	West Carrollton Reason for Rating	West Carrollton Source of Information
14	Foundation, Earthwork, and Pipe Installation Conditions	5		0				0				0		
15	Groundwater Construction Impact	3		0				0				0		
16	Geological / Seismic Activity	5		0				0				0		
17	Infrastructure (Utilities)	7		0				0				0		
18	Distance from Transmission Connection Point	7	5	35	40 miles to Fairport	State highway map	5	35	40 miles to Fairport	State highway map	4	28	61 miles to Fairport	State highway map
19	Potential Transmission Line Corridors	8		0				0				0		
20	Transmission System Stability (evaluated by AECI)	5		0				0				0		
21	Distance from Adequate Source of Cooling Water	7	5	35	Wells to be located adjacent to plant near river.	Topographic Map	5	35	Wells to be located approximately 1 mile from plant near river.	Topographic Map	3	21	Wells approximately 7 miles away near river.	Topographic Map
22	Adequacy of Cooling Water Source	7		0				0				0		
23	Cooling Water Static Head Requirements	5		0				0				0		
24	Class I Areas	8	5	40	More than 200 miles from all Class 1 Areas	Class 1 Map	5	40	More than 200 miles from all Class 1 Areas	Class 1 Map	5	40	More than 200 miles from all Class 1 Areas	Class 1 Map
25	Designated Parks and Preserves	7	2	14	2 miles to Riverbreaks State Forest Conservation Area	Topographic Map	1	7	0.8 mile to Riverbreaks State Forest Conservation Area	Topographic Map	3	21	5.2 miles to Schifferdecker Wildlife Area	Topographic Map
26	Land Planning / Zoning	7		0				0				0		
27	Existing Land Use on the Site	10	3	30	Predominantly Agriculture	Topographic Map and aerial photo	3	30	Predominantly Agriculture	Topographic Map and aerial photo	3	30	Predominantly Agriculture	Topographic Map and aerial photo
28	Existing Residences on the Site	10		0				0				0		
29	Nearby Existing Land Use	8	3	24	Predominantly Agriculture	Topographic Map and aerial photo	3	24	Predominantly Agriculture	Topographic Map and aerial photo	3	24	Predominantly Agriculture	Topographic Map and aerial photo
30	Potential Contamination	7		0				0				0		
31	Archaeological and Historical Resources	7		0				0				0		
32	Cemeteries	5		0				0				0		
33	Scenic Areas	7		0				0				0		
34	Noise Impacts	7		0				0				0		
35	Prime Farmland	5		0				0				0		
36	Dispersion Conditions	7		0				0				0		
37	Background Air Quality	8		0				0				0		

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-9. AECI Site Rating Summary - Revision 2

			East Forbes (Holt County)				West Forbes (Holt County)				West Carrollton (Carroll County)			
Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information
38	Air Quality Non-Attainment Areas	**7**	**3**	**21**	28 miles to Platte County, MO 8-hr Ozone NAA	US EPA website	**3**	**21**	33 miles to Platte County, MO 8-hr Ozone NAA	US EPA website	**3**	**21**	33 miles to Jackson County, MO 8-hr Ozone NAA	US EPA website
39	Multiple State Involvement in Permitting	**3**		**0**				**0**				**0**		
40	Fogging and Icing Impact Potential	**7**		**0**				**0**				**0**		
41	Proximity to Airports / Airstrips	**5**		**0**				**0**				**0**		
42	Wetlands Impact Potential	**10**	**3**	**30**	4 acres of wetlands affected	NWI Map	**3**	**30**	Acreage not determined		**1**	**10**	15 acres of wetlands affected	NWI Map
43	Other Natural Habitats Impact Potential	**7**		**0**				**0**				**0**		
44	Documented Occurrence of Threatened and Endangered Species	**7**	**5**	**35**	No documented occurences w/in 5 miles	State website	**5**	**35**	No documented occurences w/in 5 miles	State website	**5**	**35**	No documented occurences w/in 5 miles	State website
45	Surface Water Impact Potential	**7**		**0**				**0**				**0**		
46	Groundwater Impact Potential	**7**		**0**				**0**				**0**		
47	Nearby Towns	**8**	**1**	**8**	0.8 mile to town of Forbes	Topographic Map	**3**	**24**	3.2 miles to town of Forest City	Topographic Map	**3**	**24**	3.2 miles to town of Carrollton	Topographic Map
Simple Numerical Summary of Ratings:			**57**				**60**				**57**			
	Weighted Summary of Ratings:			**430**				**452**				**426**		

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-9. AECI Site Rating Summary - Revision 2

Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	Southwest Norborne (Carroll County)				East Ray (Ray County)				South Hardin (Ray County)			
			Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information
1	Plant Site Topography and Size	8	2	16	Site needs to be raised approximately 13' to be above 100-year flood.	Topographic Map	3	24	Site needs to be raised approximately 9' to be above 100-year flood.	Topographic Map	1	8	Site needs to be raised approximately 16' to be above 100-year flood.	Topographic Map
2	Expandability for Future Units	5		0				0				0		
3	Land Acquisition (evaluated by AECI)	7		0				0				0		
4	Distance from Potential Solid Waste Disposal Area	7	5	35	Suitable disposal area on site.	Topographic Map	5	35	Suitable disposal area on site.	Topographic Map	5	35	Suitable disposal area on site.	Topographic Map
5	Fill Required for Potential Solid Waste Disposal Area	7		0				0				0		
6	Distance from Highway	5	5	25	Less than 1 mile to Rte 10.	Topographic Map	4	20	Approximately 1 mile to Rte 10.	Topographic Map	4	20	Approximately 4 miles to Rte 10 in Hardin.	Topographic Map
7	Distance from Primary Railroad Connection	7	4	28	Approximately 2 miles to NS.	Topographic Map	4	28	Approximately 2.5 miles to NS.	Topographic Map	4	28	Approximately 2.5 miles to NS.	Topographic Map
8	Potential Rail Spur Grade	7		0				0				0		
9	Potential Rail Spur Corridors	8		0				0				0		
10	Alternate Coal and Reagent Transportation	10	5	50	Connection to BNSF can be made 23 miles west. Connection 3 miles south can be made to UP but a bridge across the Missouri river is required.	Topographic Map	5	50	Connection to BNSF can be made 16 miles west. Connection 2 miles south can be made to UP but a bridge across the Missouri river is required.	Topographic Map	5	50	Nearest alternate rail line (BNSF) is 13 miles west. A connection can be made to the UP 3 miles south but a bridge across the Missouri river is required.	Topographic Map
11	Distance from Secondary Railroad Connection	5	1	5	23 miles to BNSF connection.	Topographic Map	2	10	Nearest alternate rail line (BNSF) is 16 miles west.	Topographic Map	2	10	BNSF is 13 miles west.	Topographic Map
12	Distance from Coal Supply	7		0				0				0		
13	Flood Potential	5	1	5	Site in 100-year flood plain and not behind Federal Levee.	Topographic Map	1	5	Site in 100-year flood plain and not behind Federal Levee.	Topographic Map	1	5	Site in 100-year flood plain and not behind Federal Levee.	Topographic Map

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-9. AECI Site Rating Summary - Revision 2

Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	Southwest Norborne (Carroll County)				East Ray (Ray County)				South Hardin (Ray County)			
			Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information
14	Foundation, Earthwork, and Pipe Installation Conditions	5		0				0				0		
15	Groundwater Construction Impact	3		0				0				0		
16	Geological / Seismic Activity	5		0				0				0		
17	Infrastructure (Utilities)	7		0				0				0		
18	Distance from Transmission Connection Point	7	4	28	60 miles to Fairport	State highway map	4	28	55 miles to Fairport	State highway map	4	28	57 miles to Fairport	State highway map
19	Potential Transmission Line Corridors	8		0				0				0		
20	Transmission System Stability (evaluated by AECI)	5		0				0				0		
21	Distance from Adequate Source of Cooling Water	7	4	28	Wells approximately 3.5 miles away near river.	Topographic Map	4	28	Wells approximately 3.5 miles away near river.	Topographic Map	4	28	Wells approximately 2.5 miles away near river.	Topographic Map
22	Adequacy of Cooling Water Source	7		0				0				0		
23	Cooling Water Static Head Requirements	5		0				0				0		
24	Class I Areas	8	5	40	More than 200 miles from all Class 1 Areas	Class 1 Map	5	40	More than 200 miles from all Class 1 Areas	Class 1 Map	5	40	More than 200 miles from all Class 1 Areas	Class 1 Map
25	Designated Parks and Preserves	7	3	21	5.5 miles to Baltimore Bend Conservation Area	Topographic Map	3	21	6 miles to Battle of Lexington SHS	Topographic Map	2	14	3 miles to Battle of Lexington SHS	Topographic Map
26	Land Planning / Zoning	7		0				0				0		
27	Existing Land Use on the Site	10	3	30	Predominantly Agriculture	Topographic Map and aerial photo	3	30	Predominantly Agriculture	Topographic Map and aerial photo	3	30	Predominantly Agriculture	Topographic Map and aerial photo
28	Existing Residences on the Site	10		0				0				0		
29	Nearby Existing Land Use	8	3	24	Predominantly Agriculture	Topographic Map and aerial photo	3	24	Predominantly Agriculture	Topographic Map and aerial photo	3	24	Predominantly Agriculture	Topographic Map and aerial photo
30	Potential Contamination	7		0				0				0		
31	Archaeological and Historical Resources	7		0				0				0		
32	Cemeteries	5		0				0				0		
33	Scenic Areas	7		0				0				0		
34	Noise Impacts	7		0				0				0		
35	Prime Farmland	5		0				0				0		
36	Dispersion Conditions	7		0				0				0		
37	Background Air Quality	8		0				0				0		

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-9. AECI Site Rating Summary - Revision 2

Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	Southwest Norborne (Carroll County) Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	East Ray (Ray County) Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	South Hardin (Ray County) Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information
38	Air Quality Non-Attainment Areas	**7**	**3**	**21**	25 miles to Jackson County, MO 8-hr Ozone NAA	US EPA website	**3**	**21**	23 miles to Jackson County, MO 8-hr Ozone NAA	US EPA website	**2**	**14**	17 miles to Jackson County, MO 8-hr Ozone NAA	US EPA website
39	Multiple State Involvement in Permitting	**3**		**0**				**0**				**0**		
40	Fogging and Icing Impact Potential	**7**		**0**				**0**				**0**		
41	Proximity to Airports / Airstrips	**5**		**0**				**0**				**0**		
42	Wetlands Impact Potential	**10**	**2**	**20**	7 acres of wetlands affected	NWI Map	**3**	**30**	5 acres of wetlands affected	NWI Map	**3**	**30**	Acreage not determined	
43	Other Natural Habitats Impact Potential	**7**		**0**				**0**				**0**		
44	Documented Occurrence of Threatened and Endangered Species	**7**	**5**	**35**	No documented occurences w/in 5 miles	State website	**5**	**35**	No documented occurences w/in 5 miles	State website	**5**	**35**	No documented occurences w/in 5 miles	State website
45	Surface Water Impact Potential	**7**		**0**				**0**				**0**		
46	Groundwater Impact Potential	**7**		**0**				**0**				**0**		
47	Nearby Towns	**8**	**2**	**16**	1.5 miles to town of Norborne	Topographic Map	**2**	**16**	2.4 miles to town of Hardin	Topographic Map	**2**	**16**	2.2 miles to town of Hardin	Topographic Map
	Simple Numerical Summary of Ratings:		**57**				**59**				**55**			
	Weighted Summary of Ratings:			**427**				**445**				**415**		

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-9. AECI Site Rating Summary - Revision 2

Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	West Oxbow (Ray County)				East Oxbow (Lafayette County)			
			Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information
1	Plant Site Topography and Size	8	3	24	Site needs to be raised approximately 8' to be above 100-year flood.	Topographic Map	3	24	Site needs to be raised approximately 7' to be above 100-year flood.	Topographic Map
2	Expandability for Future Units	5		0				0		
3	Land Acquisition (evaluated by AECI)	7		0				0		
4	Distance from Potential Solid Waste Disposal Area	7	5	35	Suitable disposal area on site.	Topographic Map	5	35	Suitable disposal area on site.	Topographic Map
5	Fill Required for Potential Solid Waste Disposal Area	7		0				0		
6	Distance from Highway	5	4	20	Approximately 1.5 to 2 miles to Rte 210.	Topographic Map	4	20	Approximately 2 miles to Rte 210.	Topographic Map
7	Distance from Primary Railroad Connection	7	4	28	Approximately 1.5 miles to NS.	Topographic Map	4	28	Approximately 1.5 miles to NS.	Topographic Map
8	Potential Rail Spur Grade	7		0				0		
9	Potential Rail Spur Corridors	8		0				0		
10	Alternate Coal and Reagent Transportation	10	5	50	Nearest alternate rail line (BNSF) is about 2 miles west. A connection can be made to the UP about 2.5 miles south but a bridge across the Missouri River is required.	Topographic Map	5	50	Nearest alternate rail line (BNSF) is about 4 miles west. A connection can be made to the UP about 2 miles south but a bridge across the Missouri River is required.	Topographic Map
11	Distance from Secondary Railroad Connection	5	4	20	Nearest alternate rail line (BNSF) is about 2 miles away.	Topographic Map	4	20	Nearest alternate rail line (BNSF) is about 4 miles away.	Topographic Map
12	Distance from Coal Supply	7		0				0		
13	Flood Potential	5	1	5	Site in 100-year flood plain and not behind Federal Levee.	Topographic Map	1	5	Site in 100-year flood plain and not behind Federal Levee.	Topographic Map

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-9. AECI Site Rating Summary - Revision 2

Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	West Oxbow (Ray County) Numerical Rating (5 is Best - 1 is Worst)	West Oxbow (Ray County) Product	West Oxbow (Ray County) Reason for Rating	West Oxbow (Ray County) Source of Information	East Oxbow (Lafayette County) Numerical Rating (5 is Best - 1 is Worst)	East Oxbow (Lafayette County) Product	East Oxbow (Lafayette County) Reason for Rating	East Oxbow (Lafayette County) Source of Information
14	Foundation, Earthwork, and Pipe Installation Conditions	5		0				0		
15	Groundwater Construction Impact	3		0				0		
16	Geological / Seismic Activity	5		0				0		
17	Infrastructure (Utilities)	7		0				0		
18	Distance from Transmission Connection Point	7	4	28	57 miles to Fairport	State highway map	4	28	57 miles to Fairport	State highway map
19	Potential Transmission Line Corridors	8		0				0		
20	Transmission System Stability (evaluated by AECI)	5		0				0		
21	Distance from Adequate Source of Cooling Water	7	4	28	Wells approximately 1 mile away near river.	Topographic Map	5	35	Wells less than 1 mile away near river.	Topographic Map
22	Adequacy of Cooling Water Source	7		0				0		
23	Cooling Water Static Head Requirements	5		0				0		
24	Class I Areas	8	5	40	More than 200 miles from all Class 1 Areas	Class 1 Map	5	40	More than 200 miles from all Class 1 Areas	Class 1 Map
25	Designated Parks and Preserves	7	4	28	11 miles to Cooley Lake Conservation Area	Topographic Map	3	21	7.5 miles to Battle of Lexington SHS	Topographic Map
26	Land Planning / Zoning	7		0				0		
27	Existing Land Use on the Site	10	3	30	Predominantly Agriculture	Topographic Map and aerial photo	3	30	Predominantly Agriculture	Topographic Map and aerial photo
28	Existing Residences on the Site	10		0				0		
29	Nearby Existing Land Use	8	3	24	Predominantly Agriculture	Topographic Map and aerial photo	3	24	Predominantly Agriculture	Topographic Map and aerial photo
30	Potential Contamination	7		0				0		
31	Archaeological and Historical Resources	7		0				0		
32	Cemeteries	5		0				0		
33	Scenic Areas	7		0				0		
34	Noise Impacts	7		0				0		
35	Prime Farmland	5		0				0		
36	Dispersion Conditions	7		0				0		
37	Background Air Quality	8		0				0		

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-9. AECI Site Rating Summary - Revision 2

Item No.	Description of Characteristic	Importance Weighting Factor (10 is High - 1 is Low)	West Oxbow (Ray County)				East Oxbow (Lafayette County)			
			Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information	Numerical Rating (5 is Best - 1 is Worst)	Product	Reason for Rating	Source of Information
38	Air Quality Non-Attainment Areas	**7**	**1**	**7**	3 miles to Jackson County, MO 8-hr Ozone NAA	US EPA website	**1**	**7**	5 miles to Jackson County, MO 8-hr Ozone NAA	US EPA website
39	Multiple State Involvement in Permitting	**3**		**0**				**0**		
40	Fogging and Icing Impact Potential	**7**		**0**				**0**		
41	Proximity to Airports / Airstrips	**5**		**0**				**0**		
42	Wetlands Impact Potential	**10**	**1**	**10**	20 acres of wetlands affected	NWI Map	**1**	**10**	20 acres of wetlands affected	NWI Map
43	Other Natural Habitats Impact Potential	**7**		**0**				**0**		
44	Documented Occurrence of Threatened and Endangered Species	**7**	**5**	**35**	No documented occurences w/in 5 miles	State website	**5**	**35**	No documented occurences w/in 5 miles	State website
45	Surface Water Impact Potential	**7**		**0**				**0**		
46	Groundwater Impact Potential	**7**		**0**				**0**		
47	Nearby Towns	**8**	**2**	**16**	1.6 miles to town of Fleming	Topographic Map	**1**	**8**	0.6 mile to town of Camden	Topographic Map
	Simple Numerical Summary of Ratings:		**58**				**57**			
	Weighted Summary of Ratings:			**428**				**420**		

Note: A small error on the chart was corrected in 2006, resulting in slightly different totals for soem sites.

Table 2-10. Potential Sites Ranked According to Total Weighted Scores

Site	Total Weighted Score
West Forbes (Holt County)	452
East Forbes (Holt County)	430
West Carrolton (Carroll County)	426
East Ray (Ray County)	445
West Oxbow (Ray County)	428
Southwest Norborne (Carroll County)	427
East Oxbow (Lafayette County)	420
South Hardin (Ray County)	415

Table 2-11

New Coal Plant - Preliminary Siting Costs (2010 $ Thousands)

Item	Watson	Forbes	Norborne Area (Camden Site)	Thomas Hill 4
Coal Transportation (1)	293,020	282,351	336,078	358,940
Transmission Construction	$107,360	$81,460	$58,174	$89,405
Capacity Cost of Losses	19,500	14,700	16,800	20,400
Energy Cost of Losses (1)	18,035	13,595	15,538	18,867
345kV O&M Incremental (1)	8,647	5,865	3,572	7,256
161kV O&M Incremental (1)	720	720	720	720
Site Development costs (2) - Site fill - Water Supply	 36,607 7,523	 30,307 7,523	 18,420 7,523	 2,388 39,404
Rail connection costs to BN(2)	4,657	1,552	3,105	0
Staff cost savings (1)	0	0	0	-23,871
Plant Infrastructure Savings (2)	0	0	0	-25,000
Chapter 100 savings (3)	-100,000	-100,000	0	-100,000
Total	$396,069	$338,073	$459,930	$388,509
2nd Rail access (2) - Union Pacific - Norfolk & Southern	 54,449	 54,449	 38,926 3,105	 105,674 27,941
Total w/ 2nd Rail access - Union Pacific - Norfolk & Southern	 $445,861	 $390,970	 $495,751 $459,930	 $494,183 $416,450

Notes: Costs are in 2010 Dollars
(1) Cost represents 2010 Present Value
(2) Rough approximation of cost
(3) Preliminary savings pending county negotiations

Revision 4 - 10/28/04 **Draft**

An assessment of transmission capacity found that the transmission line to which the Watson site had originally planned to be connected (in 1981) no longer had adequate capacity. The proposed 1981 Watson site was to have been connected to the 345-kV Missouri-Iowa-Nebraska Transmission (MINT) line. However, over the past 25 years, the loads on this line have grown substantially and it no longer has adequate capacity to provide a secure outlet for a 660 MW net plant. Based on the large additional transmission costs that would now need to be considered, Watson was eliminated from further consideration.

AECI management determined that Ray County, which is part of the statistical Kansas City metropolitan area, is too close to Kansas City, and instructed staff to exclude the Norborne area sites in that county because of the greater population density, growth potential and potential air quality impacts. This left West Forbes, East Forbes, Southwest Norborne, West Carrollton, and Thomas Hill, as shown in Figure 2-41.

Another potential site in the Forbes Area was added when AECI management became aware of the availability of a single-owner piece of property with rail and river access, and a willing seller. This site, shown in Figure 2-42, was designated North Forbes. When compared with South Forbes,[33] North Forbes had marginally higher siting costs, but better transportation access from I-29 via US 159, and slightly better rail access. The proximity of Squaw Creek NWR and Big Lake State Park are negatives for North Forbes, but were not considered fatal flaws. With the addition of North Forbes and the similarity of sites within the Forbes Area, two sites in the Forbes Area were considered adequate for evaluation, and the Forbes East site, which scored a little below Forbes South in the initial evaluation, was dropped from consideration.

Further refinement in the Norborne Area led to the identification of a site between Southwest Norborne and the 1981 Norborne site. This site had lower development costs than the other remaining Norborne Area sites, and available land. It also has the advantage of being located at the very edge of the floodplain, which minimizes flood impacts. Southwest Norborne was thus dropped, as was nearby West Carrollton, which had no advantages over the relocated Norborne site.

By December 2004 the field had been narrowed to two Forbes Area sites, one Norborne Area site, and Thomas Hill. The revised site cost comparison matrix

[33] Previously designated West Forbes; also called Forbes South.

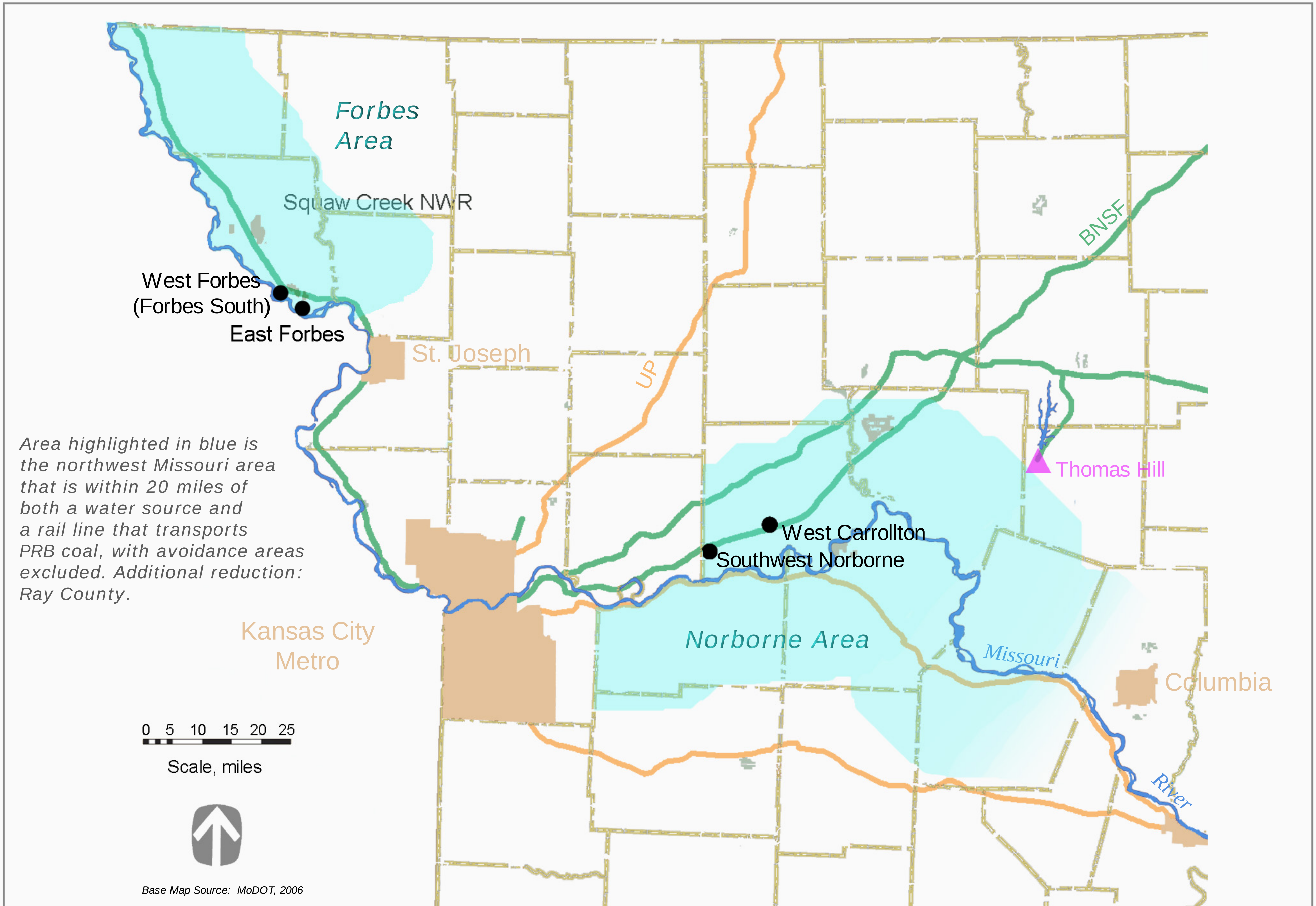
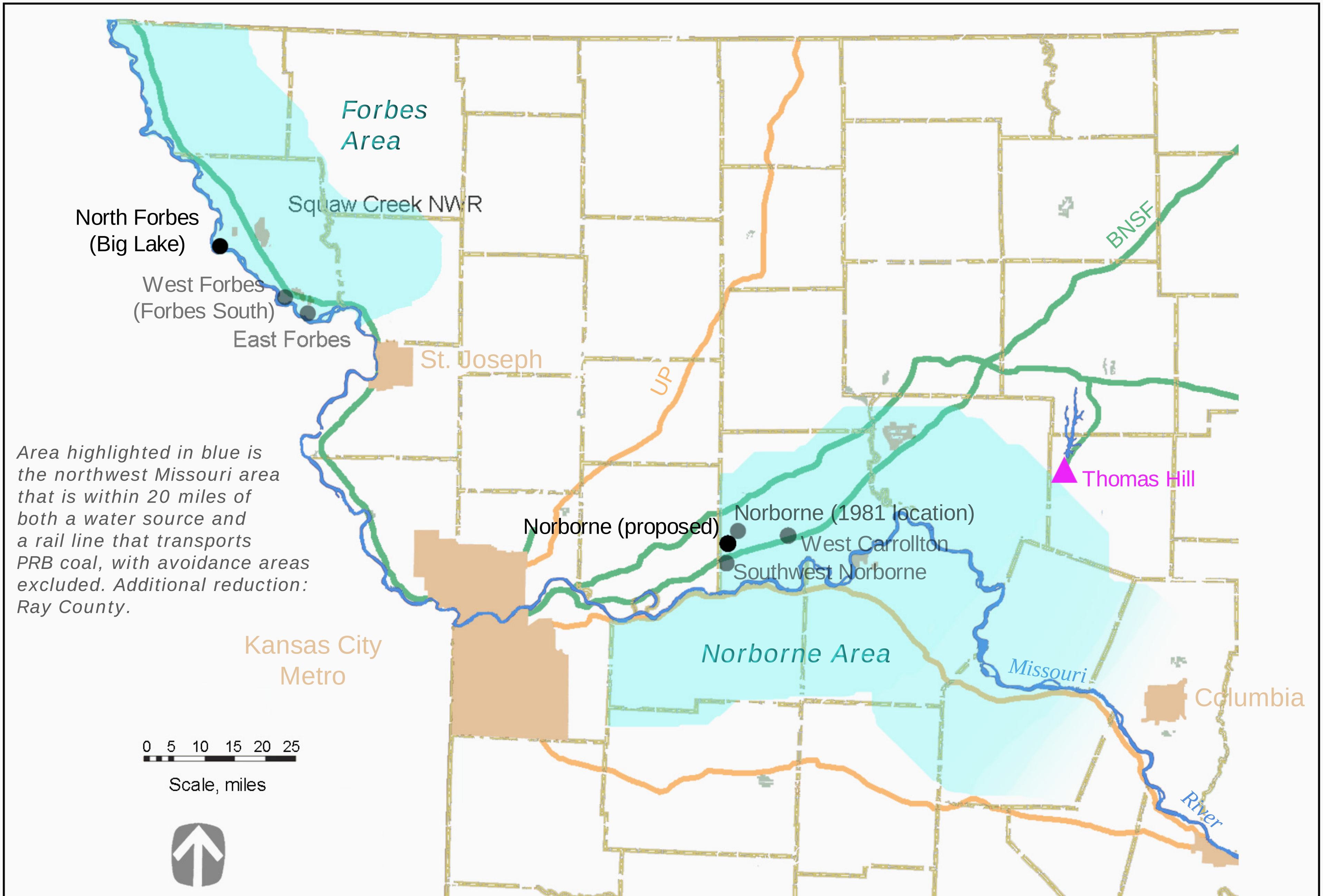


Figure 2-41. Reduced Sites, Late 2004

USDA/RD--AECI Baseload Power Plant Final EIS



Base Map Source: MoDOT, 2006

Figure 2-42. Sites, December 2004

USDA/RD--AECI Baseload Power Plant Final EIS

shown as Table 2-12 was presented to the AECI Board of Directors at their December 2004 meeting. As the table shows, Norborne has the lowest overall site development costs, followed by Thomas Hill. Based on this table, though, coal transportation costs are lowest for Forbes South and highest for Thomas Hill.

Norborne and Thomas Hill, as the two lowest-cost siting alternatives, were retained for further evaluation. The two sites in the Forbes area were too similar to retain both. The cost evaluation between the two sites was within the margin of estimation error (about 6 percent). While there were some disadvantages to the North Forbes site, AECI's management concluded impacts could be appropriately mitigated, and that the potential of dealing with a single willing landowner outweighed the disadvantages of the site. Therefore, South Forbes was eliminated from further consideration and North Forbes (Big Lake) was retained. Norborne, Big Lake, and Thomas Hill are shown in Figure 2-42.

2.2.9 Summary of New Coal-Fired Plant Siting Studies

AECI's site search was limited to Missouri, which comprises the bulk of its service area. Based on regional avoidance criteria (Class I areas, major metropolitan areas, air non-attainment areas, and large public land areas) and within Missouri, the desire as close as practical (considering other siting needs) to the Powder River Basin coal source, northwest Missouri exclusive of the Kansas City metropolitan area was targeted for site identification. In this area, the Missouri River is the only water source with the required capacity for the proposed plant, and 20 miles was considered the maximum practicable distance from the river. Two general areas were identified along the Missouri River—one in Holt County north of Kansas City (Forbes area) and one east of Kansas City in the Ray/Lafayette/Carroll County area (Norborne area). Two potential sites were identified in the Forbes area and six in the Norborne area. These sites were ranked by general engineering, cost, and environmental criteria. There was little difference in the weighted scores among the sites. Three of the sites in the Forbes area were in Ray County, which is included in the statistical Kansas City metropolitan area. These sites were eliminated because of proximity to Kansas City. Another potential site in the Forbes area, now referred to as Big Lake, was added when AECI management became aware of the opportunity to purchase this large tract of land from a single willing owner. Big Lake was similar enough to the other two Forbes area sites such that only one needed to be carried forward, and Big Lake was

Table 2-12

REVISED

Attachment A

Site Cost Comparison Matrix

(2011 $ Thousands)

Item	Forbes Area		Norborne	Thomas Hill
	Forbes South	Forbes North		
Coal Transportation Costs	$240,451	$245,325	$272,505	$293,755
Transmission Costs	$121,152	$133,803	$104,705	$130,379
Site Development Costs - Site Fill - Water Supply & Eff. Discharge(1)	 $41,713 $10,146	 $31,669 $9,429	 $31,567 $11,581	 $5,124 $12,299
Primary Rail Connection Costs to BN	$2,460	$2,050	$3,177	$0
Secondary Rail Connection Costs - Union Pacific - Norfolk & Southern (2)	 $75,637 	 $89,883 	 $3,792	 $22,958
Staffing Costs/Savings (3)	$0	$0	$0	-$25,129
Plant Infrastructure Cost/Savings (4)	$0	$0	$0	-$9,906
Chapter 100 Bond Cost/Savings (5)	-$158,698	-$158,698	-$158,698	-$158,698
Total Evaluated Costs	$332,861	$353,461	$268,629	$270,782

Notes:

(1) Assumes pumping from the Chariton River for Thomas Hill Unit 4

(2) It is possible that the secondary rail access for Thomas Hill will be built even if the new unit is located elsewhere.
-Cost of TH connection to Union Pacific is estimated at $159,884 in 2011
-Cost of Norborne connection to Union Pacific is estimated at $56,164 in 2011

(3) Cost represents 2011 Present Value, 8 years of savings only (until 2nd unit built on green field site).

(4) Plant Infrastructure savings for Thomas Hill are estimated as the present value of an 8-year deferral of:
- Avoided railroad loop track at $12.3 million in 2011
- Avoided rotary car dumper at $20.5 million in 2011
- Avoided land purchase (net) at $4.9 million in 2011

(5) Preliminary savings estimate pending county negotiations.
No negotiations have been held with Carroll County (Norborne Area)

Revision 10 - 12/7/04 DDH

selected. Further refinement in the Norborne area led to the identification of a single site that was judged to be representative of the range of reasonable alternatives in that area. Norborne and Big Lake were retained for detailed evaluation. Based on the lower overall cost of the Norborne site, and potential environmental disadvantages of Big Lake, Norborne was identified by AECI as the proposed site with Big Lake the alternate.

2.2.10 Consideration of Adding Capacity at Thomas Hill

AECI's Thomas Hill Energy Center is one of two coal-fired baseload facilities owned by AECI. It currently has a net capacity of 1,153 MW, 49 percent of the AECI-owned baseload capacity. The other baseload facility, New Madrid, has a net capacity of 1,200 MW (AECI, 2006f). Adding a 660 MW net unit at Thomas Hill would increase its net capacity to 1,813 MW, which would be 60 percent of the AECI-owned baseload capacity. Reliability becomes a concern when a large part of a utility's baseload capacity is at a single location. First, it stresses the transmission system reliability, with so much of the utility's energy coming from a single location. Secondly, with the addition of 660 MW net at Thomas Hill, a single catastrophic event could put more than half of AECI's baseload capacity at risk. As an example from another utility, Ameren UE, the largest utility in Missouri, has its baseload capacity spread over five plants, with 36 percent the maximum at any single location (Ameren, 2006b).

Another concern about adding capacity at Thomas Hill is the construction labor supply risk. First, the site is far from the large labor pools in major metropolitan areas. Secondly, environmental control project construction may be concurrent with plant construction, which would place additional stress on the labor supply. On the other hand, Thomas Hill currently has BNSF rail access, is a reasonable distance from the PRB, has its own water supply reservoir, was not eliminated by regional avoidance criteria, and is a brownfield site already owned by AECI. Primarily for these reasons it was considered as a site for the new 660 MW net unit.

2.2.10.1 Water Supply Study

A serious concern at Thomas Hill that needed to be addressed in evaluating potential for adding capacity was water supply. Based on reservoir performance during a relatively mild drought during 1987 to 1990, there was concern whether the reservoir would be adequate in a severe drought, even without adding another unit. In addition, AECI may need to add FGD systems