2.0 THE PROPOSED ACTION AND ALTERNATIVES

This section discusses the proposed action, the no-action alternative (including scenarios that are reasonably expected to result as a consequence of the no-action alternative), and alternatives dismissed from further consideration.

2.1 PROPOSED ACTION

The proposed action is for DOE to provide cost-shared funding for the design, construction, and demonstration of coal-fired LEBS technology for electric power generation at the proof-of-concept scale. Specifically, DOE will decide whether to provide funding to Babcock Borsig Power (BBP) for demonstrating LEBS technology at a new 91 MW coal-fired power plant.

2.1.1 Location

The site proposed by the BBP team for demonstrating LEBS technology is located in central Illinois, about 17 miles northeast of Springfield and about 2 miles southeast of the town of Elkhart in Elkhart Township, Logan County (Figure 2.1.1). The local terrain is primarily flat to rolling, and the principal topographic feature is Elkhart Hill, which has a maximum elevation of about 200 ft above site grade and is located slightly over 1 mile northwest of the site (Figure 2.1.2). Land use in the rural area surrounding the site is mainly agricultural. Interstate 55, a major thoroughfare between Chicago and St. Louis, passes along the northwest side of Elkhart.

The LEBS power plant would occupy about 5 acres of land adjacent to the existing underground coal mining complex on the 750-acre property owned by Turris Coal Company, a member of the project team. The 300-ft-deep coal mine has operated since 1982 and employs 235 workers to mine about 2 million tons of coal annually. At the current production rate, Turris Coal Company owns sufficient coal reserves for the mine to continue operating for over 30 additional years. Approximately 480 acres of property have been developed for supporting the mining activities, including 265 acres for combustion waste disposal; other features of the developed area include buildings, roads, coal storage piles and silos, coal conveyors, loading facilities for coal trucks, and wastewater ponds. The remaining 270 acres of the site are leased for agricultural use. The project would occupy a section of the property containing a paved road and a mowed grassy field, which currently is designated as the emergency coal storage area for the mine, but which has never been used for coal storage. No mining has occurred beneath a substantial portion of the project site. Major buildings and structures would be sited in areas where subsidence from mining activities would not be likely to occur.

2.1.2 Technology Description

The following technologies proposed for demonstration would be integrated into the design for the power plant: (1) a slagging combustor, which is U-shaped to increase the combustion reaction time; (2) low-NO_x burners, staged combustion, and coal reburning (using about 10-15% of the coal) for

NO_x control during combustion, in combination with a selective catalytic reduction (SCR) post-combustion NO_x control system; (3) a *wet limestone scrubbing system* for SO_2 capture; and (4) an electrostatic precipitator for particulate removal from the flue gas. These technologies would be expected to capture at least 96% of SO_2 emissions, achieve 85% control of NO_x, and remove 99.8% of particulate matter. Figure 2.1.3 depicts the key components in the integrated system.

Feedwater would be heated in the slagging combustor to produce steam that would drive a steam turbine connected to an electrical generator. The proposed power plant would use a conventional, sub-critical steam cycle that operates at 1,500 psi and 1,000°F. Steam used to drive the turbine would be condensed and recycled to the combustor as feedwater.

The slagging combustor would produce vitrified *bottom ash* from finely ground coal. The *fly ash* from the electrostatic precipitator would be recycled to the combustor to maximize ash discharge as vitrified ash, which would provide a salable by-product used as a road base or construction material. If a market could not be found, the vitrified ash would be mixed with mine wastes for disposal on the mine property or at a permitted CBEC site.

The wet flue gas desulfurization system would use limestone to remove SO_2. The limestone would be ground, slurried, and injected into an absorber where the slurry would react with the SO_2 in the flue gas. Gypsum, the end result of the absorption process, would be filtered, dewatered, and transported for disposal at an existing disposal site on the mine property or at a permitted CBEC site. Chlorides introduced into the facility in the coal and mine water would be mixed with gypsum before disposal.

2.1.3 Project Description

The project proposed by Babcock Borsig would incorporate the LEBS technology described in Section 2.1.2 into the new 91 MW coal-fired power plant. A conceptual layout of the proposed power plant is shown in Figure 2.1.4, and a diagram of the plant is displayed in Figure 2.1.5. The demonstration would be expected to generate sufficient data from design, construction, and operation to allow private industry to assess the potential of LEBS technology for commercial application.

The power plant would be fueled with bituminous coal from the adjacent, existing underground coal mine owned by Turris Coal Company. Currently, the Turris Coal Company uses an existing coal silo, which is depicted on Figures 2.1.4 and 2.1.5, to store mined coal that has been washed and readied for market. A conveyor is used to transport coal from the storage silo to a truck loading facility. Under the proposed project, the truck loading facility would be modified to provide direct feeding of coal onto a new conveyor that would weigh and transport coal to the new power plant.

Coal from the Turris Mine was used for combustion tests in a small U-shaped slagging combustor at a Babcock Borsig research facility; testing indicated that ash from the slagging combustor would not be hazardous (Zecco 1997). Electricity generated by the power plant would be provided to the local power grid through an existing substation. To more precisely quantify the amount of electricity to be generated, the LEBS facility would produce a net electrical output of 82 MW and a gross operating output of 91.1 MW. The internal power requirement for the plant would be about 9 MW and the balance (82 MW) would be supplied to the local power grid.

A new *mechanical-draft cooling tower* would be used to discharge heat to the atmosphere. Water in this secondary cycle would pass through the condenser to absorb heat from the steam coming from the boiler and turbine in the primary cycle. The cooled steam would condense into water, which then would be recycled to the boiler. The heated water in the secondary cycle would then be pumped to the cooling tower where a small percentage would evaporate, thus cooling the remaining water. Field drainage runoff and groundwater wells would replenish the water lost by evaporation. The water then would be returned to the condenser to repeat the cycle.

Permits and other regulatory compliance issues for the proposed project are discussed in Section 7.

2.1.4 Construction Plans

As shown in Figures 2.1.4 and 2.1.5, key structures that would be built for the proposed power plant include a turbine building; a boiler building; housing for the wet limestone scrubbing system and electrostatic precipitator; a boiler stack; a coal conveyor to connect the power plant with an existing conveyor system from the coal silo to a truck loading facility; a building for electrical equipment and controls; on-site electric transmission lines and towers that would traverse Township Road 600N to connect a new transformer for the power plant with an existing substation on the mine property; a cooling tower; water storage tanks; and storage structures for fly ash, bottom ash, and gypsum. Because the power plant would occupy a nearly level site containing a paved road and a mowed field, minimal site clearing and grading would be required. Nearby land uses would not be affected by plant construction activities.

Under current plans, the construction period for the proposed plant would extend over 24 months. On average, approximately 100 construction workers would be on the project site during the construction period. The peak number of construction workers on the site would be about 180.

2.1.5 Operational Plans

Demonstration of the proposed LEBS technology, including performance testing and monitoring, would be conducted for approximately 4,000 hours during a 6-month period. Approximately 25 new employees would be required to operate and maintain the power plant. If the demonstration is successful, full-time commercial operation of the plant would follow immediately. During commercial operation, the plant would be used as a baseload power plant operating 24 hours per day, 7 days per week, at an 85% annual *capacity factor*. The power plant would be designed for a lifetime of 35 years.

2.1.6 Resource Requirements

Operating characteristics, including resource requirements, during demonstration of the proposed technology are presented in Table 2.1.1.

2.1.6.1 Land Area Requirements

Land requirements for construction include areas for equipment/material laydown, temporary storage, assembly of site-fabricated components, construction equipment access, and temporary facilities to be used by the construction work force (i.e., offices and sanitary facilities). The 750 acre property owned by Turris Coal Company would easily accommodate these land requirements. The proposed facility would occupy about 5 acres of the property. A 15 ft deep, 22 acre retention pond for collecting field drainage runoff would be located east of the project site and south of Township Road 600N on Turris Coal Company property (Figure 2.1.2). The retention pond would be established in consultation with the Illinois Department of Natural Resources; the pond may be located on Turris property farther south from the site depicted on Figure 2.1.2.

2.1.6.2 Water Requirements

During construction, groundwater obtained from wells would be used for concrete formulation, equipment washdown, general cleaning, and dust suppression. Potable water would be provided by the construction contractor from off-site sources or the new wells. During operation, total water use at the proposed plant would be about 1,195 gallons per minute (gpm) (1.72 million gallons per day (MM gpd)), with about 75% used to replace water evaporated in the plant's cooling tower. The plant's water needs would be provided primarily by field drainage runoff from a 2,540 acre drainage area (Figure 3.3.2), which would feed the new 22 acre retention pond sized to hold about 50 days supply of water, and up to six new groundwater wells. One proposed well would be located in the northwest corner of Turris Coal Company's property in the vicinity of the water supply well for the village of Elkhart, and the other five wells would be located approximately two miles to the east.

The field drainage runoff would be piped to the retention pond, which would be constructed on the eastern side of Turris property (Figure 2.1.2). The retention pond fed by the field tile drains would function to simplify water management and allow the proposed plant to continue operations without substantial water impacts during a major drought period. Flow in the field tile drains would fluctuate seasonally, with a maximum measured flow of 2.0 MM gpd. Due to seasonal variations in rainfall, and during periods of drought, the field tile drains may not be sufficient to maintain adequate storage in the retention pond for servicing the needs of the power plant. During these periods, groundwater wells would provide the primary source of make-up water to the cooling tower. Well water, which could contain low concentrations of impurities, such as carbonates or sulfates of lime and magnesia and oxides of iron, aluminum, and silicon that result in scale formation or corrosion in boilers, would be treated to produce demineralized water that would provide the source of water to the plant's boilers. Except during some summer months and during droughts, water flows through the field drainage area and into Lake Fork Creek. The proposed plant would capture and use the water available from this source.

Table 2.1.1. Operating characteristics of the proposed LEBS power plant

Operating characteristic	Quantity
Capacity, MW	91[a]
Capacity factor[b], %	85
Power production, MWh/year	677,600
Size of power plant site, acres	5[h]
Coal consumption, tons/hour	47
Water use, gpm	
Cooling tower evaporation and drift loss	904
Cooling tower makeup	1,084
Boiler feedwater[c]	29
Boiler evaporation	10
Water softening sludge	55
Sanitary use	3
Slag evaporation and by-product (waste) loss	16
FGD evaporation and by-product (waste) loss	120
Boiler feedwater treatment wastewater	16
Anhydrous ammonia (for NO_x control), lb/hour	260
Limestone (for SO_2 capture), lb/hour	10,729
Air emissions, lb/hour	
Sulfur dioxide, SO_2	238[i]
Nitrogen oxides, NO_x	125[i]
Particulate matter, PM	24[i]
Carbon monoxide, CO	188[i]
Volatile organic compounds, VOCs	29[i]
Carbon dioxide, CO_2	208,000
Effluents, gpm	
Cooling tower blowdown[d]	180
Water treatment waste (softener regenerate waste)	55
Sanitary waste[e]	3
Slag waste and FGD waste	43
Solid waste, lb/hour	
Vitrified ash (slag)[f]	9,400
Gypsum[g]	24,118

[a]The LEBS facility would achieve a guaranteed net electrical output to the local grid of 82 MW from a gross operating output of 91 MW. The internal power requirement for the facility would be about 9 MW.

[b]Capacity factor is the ratio of the energy output during a specified period of time to the energy that would be produced if the equipment had operated with maximum power production during that period.

[c]Supplied by demineralized well water.

[d]This nonpotable water would be discharged to the mine's coal washing, FGD, and slag handling water supply.

[e]Sanitary waste would be treated using the existing sewage treatment plant.

[f]To be marketed for sale as road base or construction material, or for disposal at a permitted site.

[g]For disposal at a permitted site.

[h]An additional 22 acres would be used for a water retention pond, thus increasing total land usage to 27 acres.

[i]The air permit issued by the Illinois Division of Air Pollution (Appendix D) contains permissible emission rates lower than used in the EIS – SO_2 by 45% to 133 lb/hr, NO_x by 13% to 109lb/hr, PM by 25% to 18 lb/hr, CO by 4% to 181 lb/hr, and VOCs by 80% to 6 lb/hr. The air quality analysis in the EIS thus overestimates impacts and provides a more conservative analysis than would be experienced based on the emission rates in the approved permit.

About 904 gpm of water would be used to replace water lost by cooling tower evaporation and *cooling tower drift*. Approximately 29 gpm would be used as boiler make-up to replace boiler *blowdown* and drift losses. Wastewater from boiler feedwater treatment (16 gpm), equipment maintenance (2 gpm), and cooling tower blowdown (118 gpm) would be used as make-up water (136 gpm) for the wet limestone scrubbing system and the slag handling system. A portion of this water would be incorporated into by-product materials that would either be marketed or transported for disposal as waste at off-site facilities. About 62 gpm of cooling tower blowdown would be discharged to the Turris Mine freshwater pond, which is used as a source of water for washing coal. About 3 gpm of potable water would be required for sanitary use at the power plant.

Figure 2.1.6 presents a water flow diagram depicting water requirements and discharges associated with the proposed plant in relation to the existing mine. The figure provides water flow data representing normal operations, whereby 100% of the cooling tower make-up would be provided from the field-tile-drain-supplied retention pond. Two additional operating scenarios exist for the cooling tower – make-up water could be supplied totally from the groundwater wells, or both wells and the retention pond could be used to provide the make-up water.

Although Figure 2.1.6 indicates a direct connection between the wells and the retention pond, a more cost-effective approach may be to connect the water supply line from the wells directly to the water conditioning unit (i.e., lime softener). This approach would eliminate the cost of installing pipe and flow controls for transporting water from wells to the retention pond and would reduce evaporation loss at the retention pond, by providing water on demand directly to the lime softener from the wells rather than from the retention pond. The decision between these approaches would not affect the water balances and would be considered during final design of the power plant.

2.1.6.3 Fuel Requirements

The proposed combustor would be fueled with bituminous coal from the adjacent, existing underground coal mine. The heating value of the coal expected to be received at the power plant site would be 10,450 Btu/lb, the sulfur content would be 3%, the ash content would be 9.5%, and the moisture content would be 17.5% (Table 2.1.2). At full load conditions, the combustor would consume coal at a rate of 47 tons per hour. Because of periodic down time, approximately 110,000 tons of coal would be burned during the 6-month demonstration. Based on an 85% annual capacity factor, average annual coal consumption would be about 350,000 tons during commercial operation. The mine can easily accommodate an approximately 17% increase in mining from the current level of 2 million tons of coal annually to supply the needs of the power plant. Increased production from the mine, assuming that coal deliveries to other customers would not change, would decrease the useful life of Turris Coal Company's existing reserves by 17%. Additional coal reserves are available to Turris Coal Company for future acquisition, if needed.

Table 2.1.2. Composition of coal from the Turris Mine, as expected to be received by the proposed power plant

Characteristic	Typical value
Heating value, Btu/lb	10,450
Analysis, percent by weight	
Moisture	17.5
Carbon	57
Hydrogen	4
Nitrogen	1
Sulfur	3
Ash	9.5
Oxygen	7
Chlorine	0.1
Total	100[a]

[a]Rounded to 100.

Source: Turris Coal Company.

The typical composition of the ash produced from Turris Mine coal is shown in Table 2.1.3.

Table 2.1.3. Typical composition of ash produced from Turris Mine coal

Constituent	Weight Percent
SiO_2	55.27
Al_2O_3	15.18
TiO_2	1.00
Fe_2O_3	17.18
CaO	3.61
MgO	0.61
K_2O	1.62
Na_2O	1.32
SO_3	4.23
Total	100

2.1.6.4 Construction and Other Materials

Locally obtained construction materials would include crushed stone, sand, and lumber for the proposed power plant and temporary structures such as enclosures, forming, and scaffolding. About 10,730 lb/hour of limestone would be used for SO_2 capture in the wet flue gas desulfurization system. The limestone would be delivered by truck and stored in a concrete storage structure. The limestone would be wet-ground and slurried with water before being used in the absorber of the flue gas desulfurization system. About 260 lb/hour of anhydrous ammonia would be used for NO_x control in the post-combustion NO_x control system. The anhydrous ammonia would be transported by truck to the site and stored as a liquid in a storage tank.

2.1.7 Outputs, Discharges, and Wastes

Table 2.1.1 includes a summary of discharges and wastes from the proposed power plant.

2.1.7.1 Air Emissions

During the demonstration period, air emissions from the combustor would include 238 lb/hour of SO_2, 125 lb/hour of NO_x, 24 lb/hour of particulate matter, 188 lb/hour of carbon monoxide (CO), and 29 lb/hour of *volatile organic compounds* (VOCs). Trace emissions of other pollutants, including beryllium, sulfuric acid mist, mercury, hydrochloric acid, benzene, arsenic, and various heavy metals, would be produced. The Illinois Environmental Protection Agency (IEPA) has classified the proposed facility as a major source of hazardous air pollutant (HAP) emissions because the potential HAP emissions from the plant would exceed 10 tons per year for an individual HAP – hydrogen chloride (Appendix D). The combustor also would create about 208,000 lb/hour of CO_2, which is not considered an air pollutant but which is a contributor to the atmospheric greenhouse effect that is suspected to cause global warming and climate change (IPCC 1992).

2.1.7.2 Liquid Discharges

About 62 gpm of blowdown from the power plant's cooling tower would be discharged to the existing freshwater pond at the Turris Mine. The slag handling and FGD systems would discharge an estimated 8 gpm and 35 gpm, respectively, of potential waste materials for off-site disposal. In addition, up to 55 gpm of sludge resulting from the conditioning of water use in the cooling tower would be discharged for off-site disposal. Sanitary wastes (approximately 3 gpm) would be treated using the existing sewage treatment plant at the Turris Mine. No other liquid discharges would be anticipated during normal operations. During extreme precipitation events, the field drainage retention pond could fill and exceed the designed storage capacity. Design of the retention pond would include a spillway that would discharge water to Lake Fork Creek if the capacity of the retention pond should be exceeded.

2.1.7.3 Solid Wastes

The proposed plant would generate about 9,400 lb/hour of coal combustion ash in the form of vitrified ash (slag). Fly ash collected in the electrostatic precipitator would be recirculated to the combustor, which would convert the fly ash into additional inert, non-leachable vitrified ash. The wet flue gas desulfurization system would generate approximately 24,000 lb/hour of gypsum.

The slag produced from combustion of coal would be sold for use as a road base or construction material. If a market could not be established, the slag and the gypsum produced by the wet flue gas desulfurization system would be transported for disposal at the mine's on-site disposal facility or at a permitted CBEC site. As discussed in Section 6.0, Turris Coal Company has obtained a permit to construct a new 72 acre, coal combustion waste disposal facility that would provide ample disposal capacity for combustion wastes from existing customers and from the LEBS demonstration. Construction of this waste disposal facility would depend on future demand.

No hazardous wastes would be generated from operation of the proposed power plant. All ash and gypsum from the facility would be nonhazardous. Occasionally, the hoppers used to collect fly ash prior to reinjection into the combustor would need to be cleaned. On these occasions, the ash removed from the hoppers would be analyzed to determine the proper method for disposal. While the Turris Coal Company's slurry pond is already permitted to accept such waste, material cleaned from the hoppers may be transported for off-site disposal in a permitted landfill.

The gypsum product would also be tested prior to transport to any off-site landfill. Any other wastes generated by the proposed plant would be similar to wastes generated at modern conventional power plants, which typically do not produce hazardous wastes.

2.2 ALTERNATIVES

Section 102(2)(C) of NEPA requires an EIS to include a discussion of reasonable alternatives to the proposed action. The term "reasonable alternatives" is not self-defining, but rather must be determined within the context of the proposed action. The goals of the Federal action establish the limits of reasonable alternatives. For LEBS technology development, DOE established the goal of demonstrating promising coal technologies that would operate efficiently and decrease the cost of electricity while reducing emissions of SO_2, NO_x, and particulate matter below mandated levels. DOE's purpose in proposing to proceed with Phase IV of the LEBS project is to demonstrate the technology's viability in achieving DOE's goal at a commercial scale. Reasonable alternatives to the proposed action must be capable of meeting this purpose.

DOE is pursuing the LEBS goal by considering partial financial support for the project owned and controlled by the Babcock Borsig team. This ownership situation places DOE in a much more limited role than if the Federal government was the owner and controller of the project. If DOE was the owner, DOE would be responsible for a comprehensive review of reasonable alternatives for siting a plant to demonstrate LEBS technology. However, in dealing with a project proposed by the private sector, the scope of alternatives is necessarily more restricted. In such cases, DOE must give substantial weight to the needs of the proposer in establishing reasonable alternatives for achieving DOE's goals.

Based on the foregoing discussion, the only reasonable alternative to the proposed action is the no-action alternative (including scenarios reasonably expected as a consequence of the no-action alternative).

2.2.1 No-Action Alternative

Under the no-action alternative, DOE would not provide cost-shared funding to the Babcock Borsig team for demonstrating LEBS technology. The commercial readiness of the LEBS technology for higher efficiency, cost-competitive power generation with improved removal of SO_2, NO_x, and particulate matter would not be demonstrated at Elkhart, Illinois, because the Babcock Borsig team would not assume the financial risk associated with the project without DOE funding. The technology probably would not be demonstrated elsewhere in the near future because no plans for a similar project are known to exist. Consequently, commercialization of the technology would be delayed or might not occur because the utility and industrial sectors tend to apply known and previously demonstrated technologies rather than new and unproven technologies.

Under the no-action alternative, the only reasonably foreseeable scenario is that the proposed power plant in Elkhart, Illinois, would not be built. This scenario would not contribute to DOE's LEBS goal of demonstrating promising coal technologies that operate efficiently and decrease the cost of electricity while reducing emissions of SO_2, NO_x, and particulate matter below mandated levels. In the absence of technology demonstration, opportunities for penetration of the technology into the commercial marketplace would not be realized. Further, the mutually beneficial arrangement between the proposed power plant and the adjacent existing coal mine would not be realized (i.e., no coal would be provided by the coal mine to the power plant, and no source of low-cost electricity would be available to the mine from the local power grid). Temporary construction jobs and permanent new jobs at the power plant and the coal mine would not be created. Potential benefits to regional air quality that could result from the electricity generated by the proposed plant displacing electricity supplied by older, less efficient power generation facilities that have higher air pollution emission rates would not be realized.

Under the no-action scenario, no construction activities or changes in operations at the proposed site would occur. No change in current environmental conditions at the site would result, and the impacts would remain unchanged from the baseline conditions. Table 2.2.1 presents a comparison of potential impacts from the proposed action and the no-action alternative.

2.2.2 Alternatives Dismissed from Further Consideration

The following sections discuss alternatives that were initially identified and considered by DOE and the Babcock Borsig team, and alternatives that were raised during the scoping process. The Babcock Borsig team conceived, designed, and proposed the 91 MW power plant in Elkhart, Illinois, in response to the LEBS solicitation that was issued by DOE in December 1990 (Section 1.1). Because DOE's role would be limited to providing cost-shared funding for the proposed power plant, reasonable alternatives are narrowed. The following candidate alternatives were identified and considered but were dismissed from further consideration.

2.2.2.1 Alternative Sites

Several sites were considered by the Babcock Borsig team for the proposed power plant. A site at an industrial park in Du Quoin, Illinois, was evaluated. Although the site was near several existing coal mines, coal would need to be delivered to the site by truck, which would substantially increase the cost of coal delivered to the site in comparison with the cost of coal delivered to the Elkhart site from the Turris Mine. Also, the Du Quoin site did not offer the required infrastructure and support facilities for power plant operations, such as water supply and storage, wastewater treatment, and roads designed for coal truck traffic. Finally, the Du Quoin site was on the edge of town near several residences.

The retired Chanute Air Force Base in Rantoul, Illinois, was also considered. Although this site contained infrastructure to support the proposed power plant, including several coal-fired boilers used for district heating, the cost of transporting coal to the site would be high due to the distance from any active mines.

The Babcock Borsig team selected the Turris Mine site due to the ready availability of a coal source and the favorable infrastructure. Coal would be available at an attractive price without extra hauling and handling. Personnel and administrative facilities could be shared by operations at the coal mine and the proposed power plant. Also, existing land use at the Turris Mine, consisting of industrialized activities remote from residences, would be compatible with the proposed plant.

2.2.2.2 Alternative Technologies

As discussed in Section 1.1, the project proposed by Babcock Borsig Power was selected to demonstrate a particular type of low emission combustion technology. DOE's National Energy Technology Laboratory conducted a competitive solicitation in 1990 to identify industry-conceived LEBS technologies for cost-shared support. DOE selected the LEBS technology proposed by the Babcock Borsig team for Phase IV demonstration. Coal-fired projects using other technologies might not achieve the LEBS goals (Section 1.2.1), and other technologies and approaches that do not use coal (e.g., natural gas, wind power, solar energy, and conservation) would not achieve those goals. Furthermore, because of fuel availability, a coal-fired facility would be the only reasonable power generation technology for location at the Elkhart, Illinois, site.

2.2.2.3 Other Alternatives

Other alternatives, such as delaying or reducing the size of the proposed power plant, have been dismissed as not reasonable. Delaying the construction or operation of the plant would not result in any reduction of environmental impacts, but delays could adversely affect DOE's plans for demonstrating the technology. The design size proposed by Babcock Borsig for the power plant was selected to assure technology operations at a scale sufficient to convince utility companies that the technology, once demonstrated at this scale, could be applied to similarly sized or larger combustors, without further scale-up to verify operational or economic performance.

2.2.3 Preferred Alternative

The NEPA regulations established by the Council on Environmental Quality (40 CFR 1502.14e) require a Federal agency to identify in a Final EIS, or in a Draft EIS if known at the time of Draft EIS preparation, the preferred alternative or alternatives for accomplishing the agency's purpose. A preferred alternative is the alternative that an agency believes would best fulfill the agency's statutory mission and responsibilities after thorough consideration of economic, environmental, technical, and other factors. For DOE's purpose of demonstrating the commercial viability of integrated, reliable, low cost, and highly efficient technologies for achieving reduced emissions from pulverized coal-fired power generation systems, DOE's preferred alternative is the proposed action for providing cost-shared funding to BBP for design, construction, and operational demonstration of the proposed LEBS power plant at Elkhart, Illinois.