2. THE PROPOSED ACTION AND ALTERNATIVES

2.1 PROPOSED ACTION

DOE has two proposed actions: first, to provide financial assistance and, second, to issue a loan guarantee to the proposed Kemper County IGCC Project at a site in Mississippi (see Section 1.4). The proposed actions are described in the Subsections 2.1.1 and 2.1.2, and connected actions are described in Section 2.2. Sections 2.3 and 2.4 address construction and operation plans, respectively, for the project. Resource requirements are summarized in Section 2.5, and Section 2.6 characterizes outputs, discharges, and wastes from the project. Finally, Section 2.7 presents the reasonable alternatives considered by DOE.

2.1.1 PROJECT SITE LOCATION AND GENERAL DESCRIPTION

The Kemper County IGCC Project would be located on a site in rural southern Kemper County. Figure 2.1-1 illustrates the site. The town of De Kalb, the Kemper County seat, is located 10 miles northeast of the site, while the city of Meridian in Lauderdale County is approximately 20 miles to the south. The Kemper-Lauderdale County line is 4 miles south of the site. The Alabama state line is approximately 23 miles east of the site.

The proposed IGCC electric generating facility would be constructed on a portion of an approximately 1,650-acre undeveloped site. Figure 2.1-2 depicts the site on a USGS topographic map. Figure 2.1-3 shows the site on an aerial photograph taken during the spring of 2008. (Both figures show a small parcel along Mississippi State Highway [MS] 493 [indicated with an X] that is not part of the site.) The site consists principally of uplands; however, there are some wetlands. The former consist mostly of managed pine timberlands, large portions of which have been clear-cut, while the latter are mostly mixed hardwood forests. The site's topography is characterized by undulating sand/clay hills, and land elevations vary from 400 feet above mean sea level (ft-msl) along a creek in the southwestern corner to 500 ft-msl in the northeastern corner. The site is characteristic of the surrounding area.

Chickasawhay Creek skirts the site's western boundary. The site is also intersected by several intermittent creeks. The small community of Liberty straddles MS 493 at the site's northern boundary. The recent aerial photograph (Figure 2.1-3) also shows a cleared area in the northeastern portion of the site where Mississippi Power has constructed a water supply test well.

The major permanent facilities of the proposed IGCC power plant, including certain supporting facilities and infrastructure, would likely occupy approximately 300 to 550 acres of the 1,650-acre site. Additional site acreage would be used during construction. Other portions of the site would be used for mine-related facilities, as discussed later, and would require approximately 350 more acres, some only temporarily.

Mississippi Power plans to acquire additional properties adjacent to its proposed power plant site for use as buffer areas. Figure 2.1-4 shows the properties that have been optioned or acquired as well as properties that Mississippi Power intends to acquire. The additional parcels (shown in green in Figure 2.1-4) total approximately 356 acres, while the remainder (shown in red) would total approximately 1,039 acres. None of the roughly 1,400 additional acres of planned buffer land would be used during project construction or for permanent project facilities.

File: M:\acad\080295\EISreport\Fig2.1-1_Project_Site.mxd

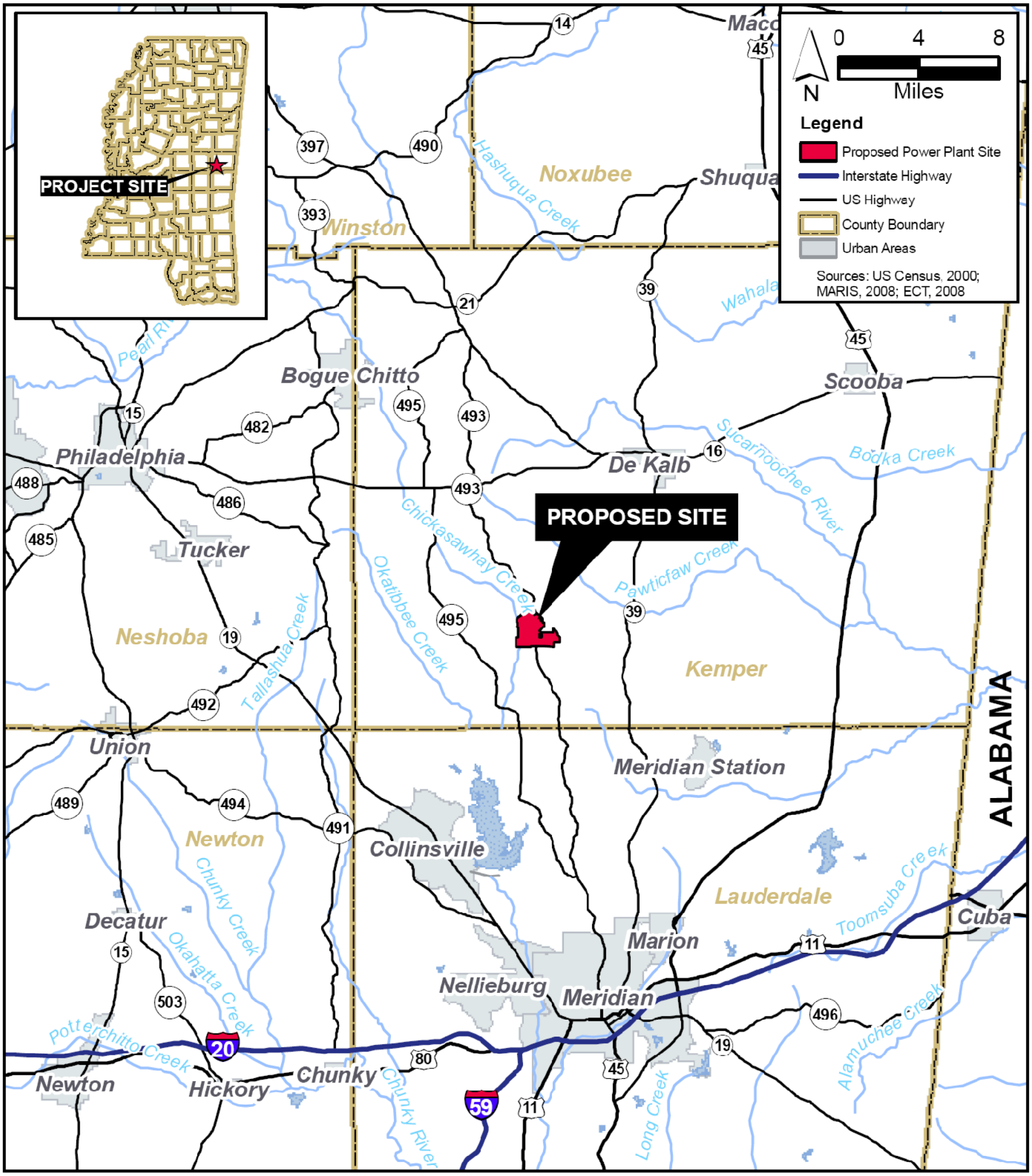

Figure 2.1-1. Location of the Proposed Kemper County IGCC Project Site

Sources: U.S. Census, 2000. MARIS, 2008. ECT, 2009.

File: M:\acad\080295\EISreport\Fig2.1-2_Topo_Site.mxd

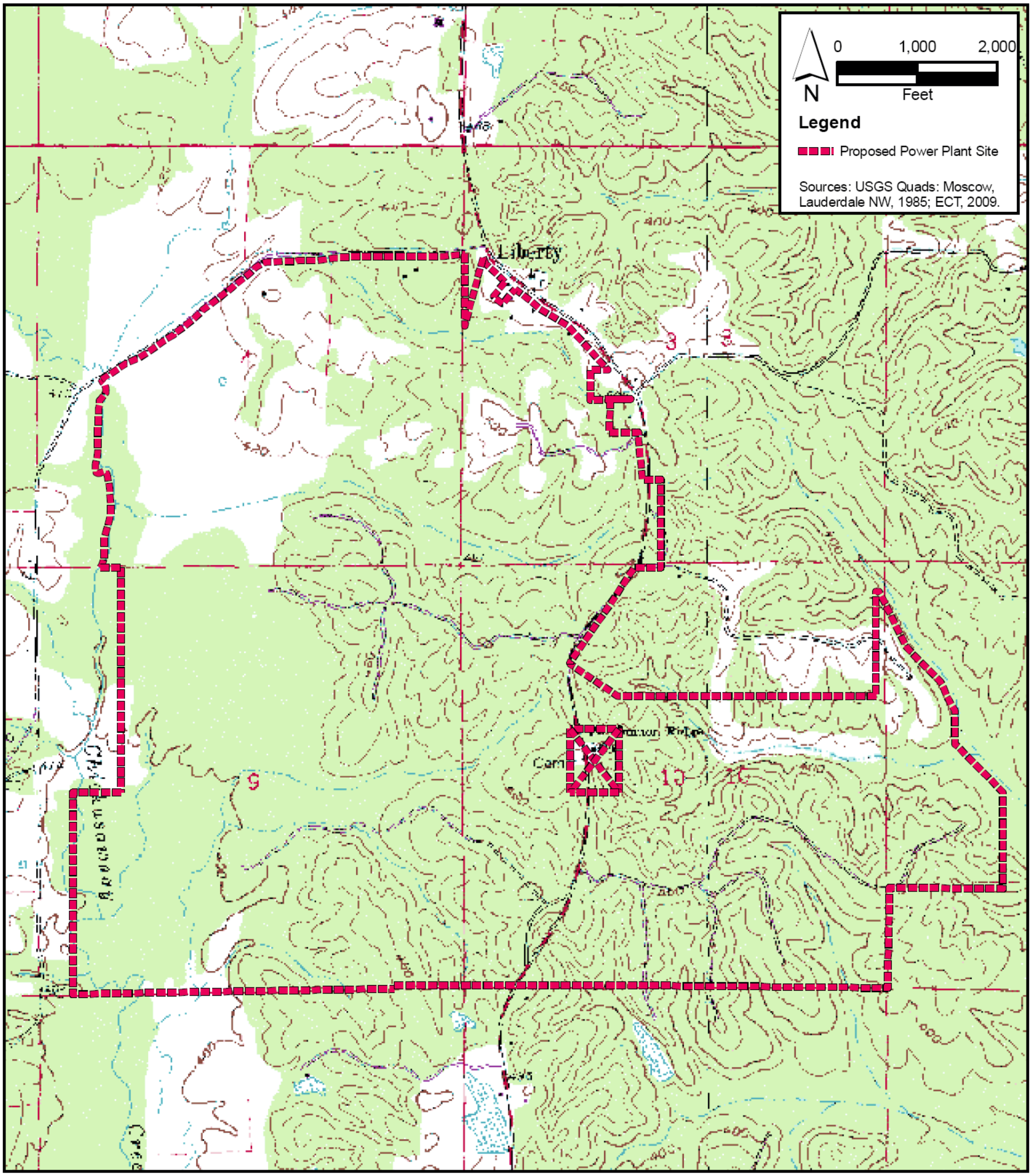

Figure 2.1-2. Topography of the Proposed Kemper County IGCC Project Site
Sources: USGS Quadrangles, Moscow, Lauderdale Northwest, 1985. ECT, 2009.

File: M:\acad\080295\EISreport\Fig2.1-3_Aerial_Site.mxd

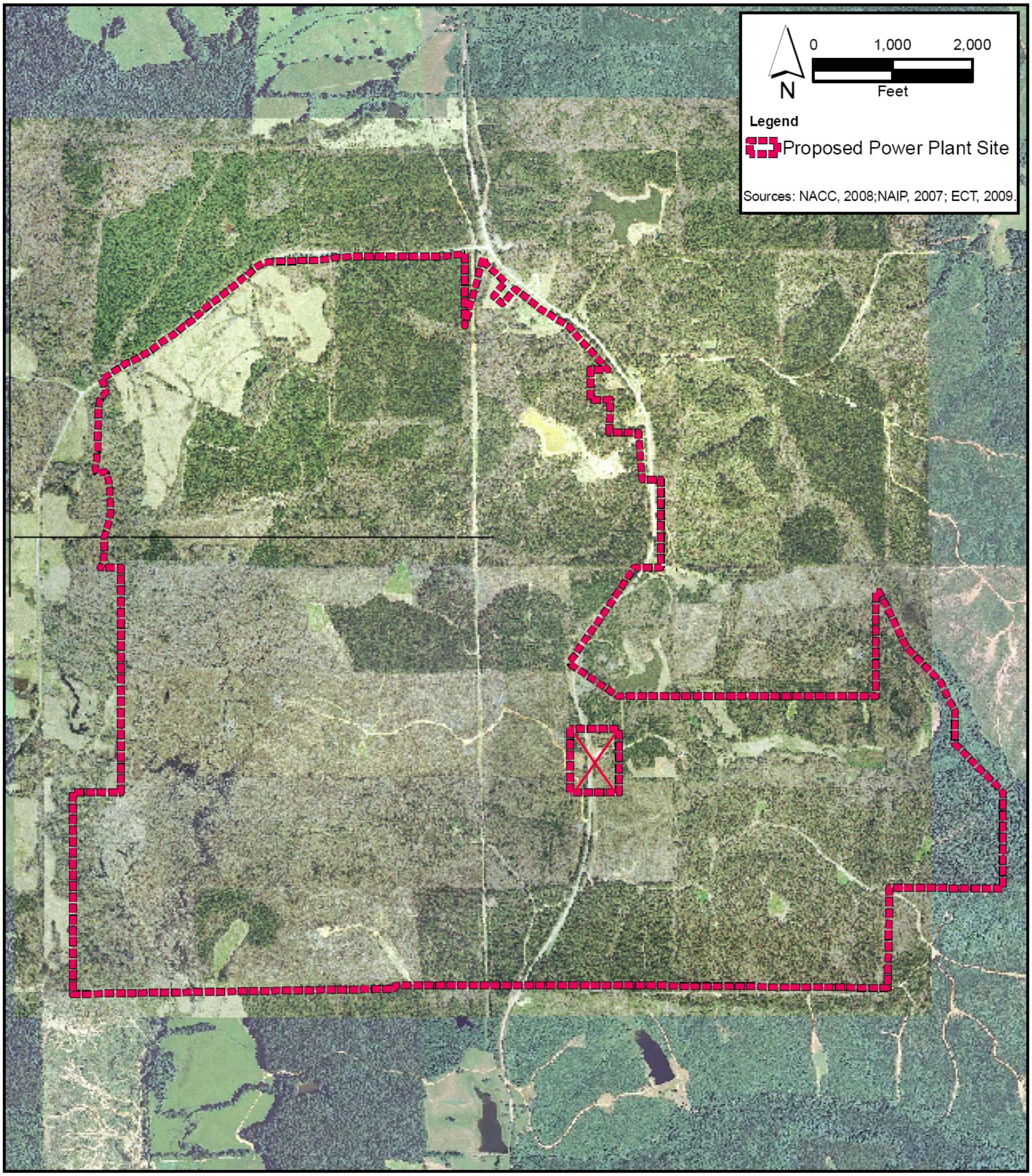

Figure 2.1-3. Aerial Photograph of the Proposed Kemper County IGCC Project Site
Sources: NACC, 2008. ECT, 2009.

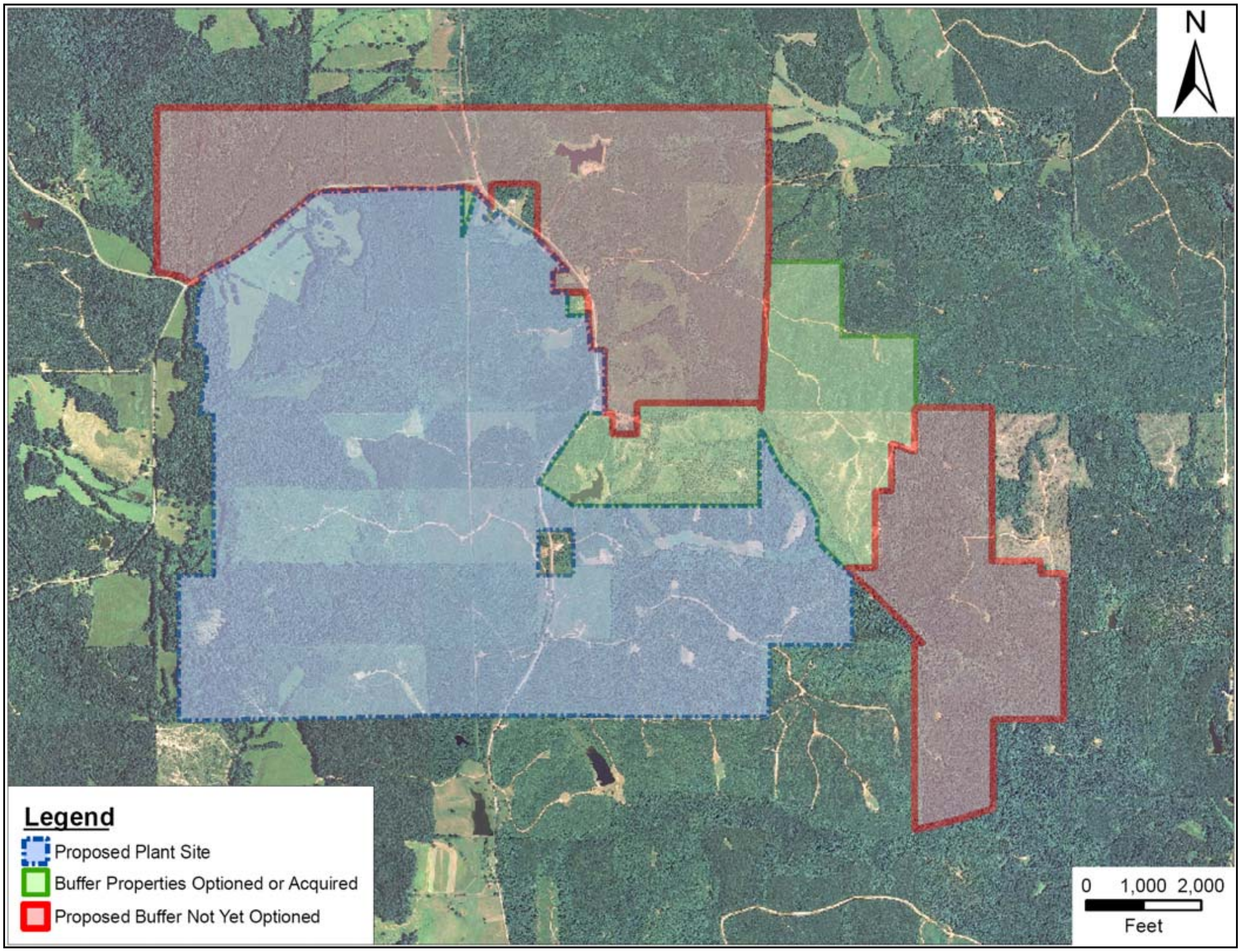

Figure 2.1-4. Proposed Power Plant Site Buffer Areas
Sources: NACC, 2008. ECT, 2010.

2.1.2 TECHNOLOGY AND PROJECT DESCRIPTION

The proposed Kemper County IGCC Project would demonstrate air-blown coal gasification and syngas cleanup systems, which would be integrated with a standard combined-cycle power-generating unit to form an IGCC power plant. Syngas derived from coal in the gasifier would be used as the fuel for the combined-cycle power generating unit. In a combined-cycle unit, fuel gas is combusted in one or more CTs, and hot exhaust gas exiting the CTs is then used to heat water into steam to drive a steam turbine. The use of the CTs' exhaust heat to power a steam turbine constitutes the combined-cycle approach, which is a proven and reliable method for increasing the amount of electricity that can be generated from a given amount of fuel. The two CTs and steam generator for the Kemper County IGCC Project would generate a nominal 582 MW (net) of electricity when duct firing natural gas in the HRSG. The project is expected to provide Mississippi Power customers a source of electricity that is reliable, low-cost, environmentally sound, and efficient. A key performance target for the proposed technology would be achieving gasifier availability of at least 80 percent without the use of a spare gasifier.

The facilities would convert lignite coal into syngas for generating electricity while reducing SO_2, NO_x, mercury, and particulate emissions as compared to conventional lignite-fired power plants. The plant would also capture a portion of the carbon from the syngas for compression and delivery for beneficial use in existing EOR operations in Mississippi to reduce CO_2 emissions from the facility (see Subsection 2.1.2.11).

The overall IGCC facilities can be divided into two major systems or components: lignite coal gasification and combined-cycle power generation. Figure 2.1-**5** provides a flow diagram of the overall proposed project.

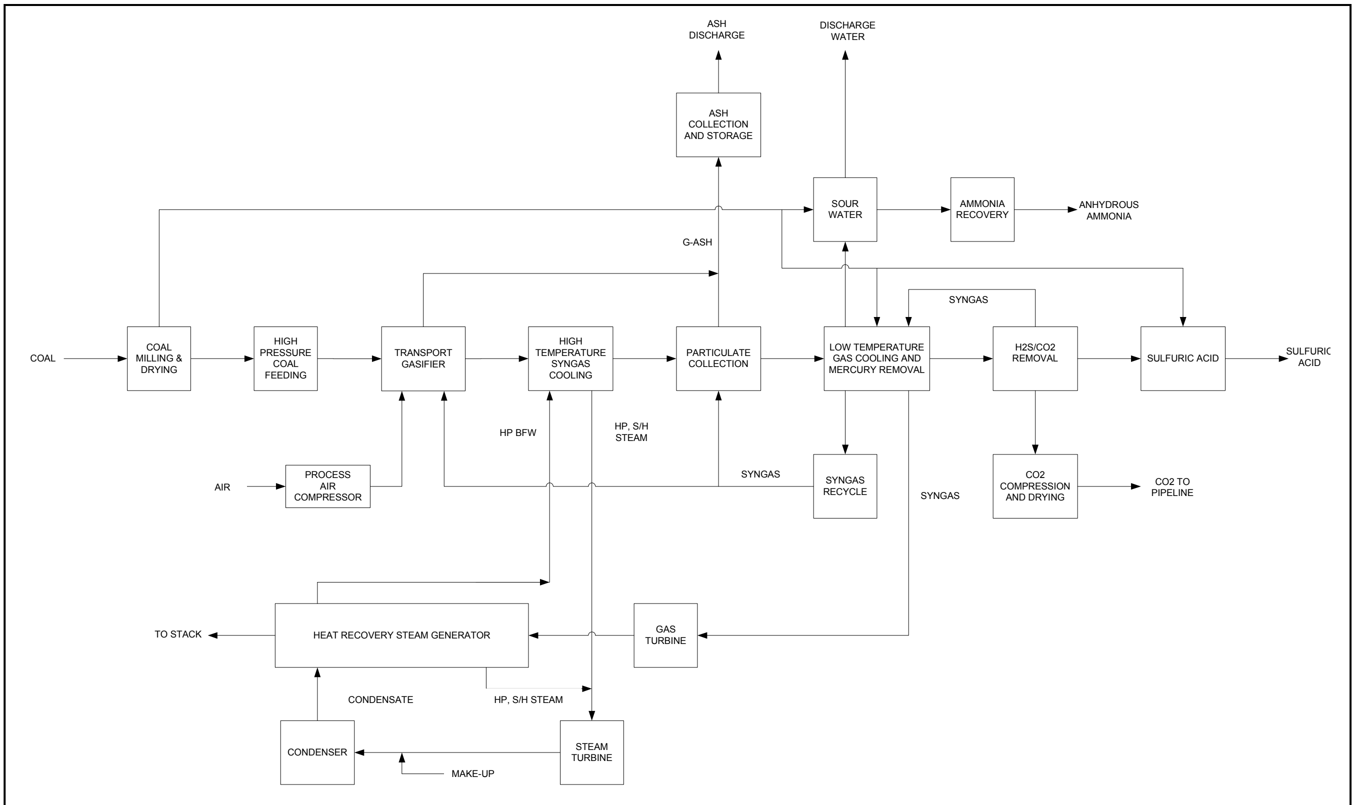

Figure 2.1-5. Process Flow Diagram of Proposed Kemper County IGCC Project
Source: SCS, 2008.

The gasification component would consist of two lignite coal gasifiers utilizing TRIG™ IGCC technology, syngas cleanup systems, a cooling tower, and other supporting infrastructure. The combined-cycle component's principal equipment would include two gas CTs, two HRSGs, a single steam turbine, a separate cooling tower, and associated support facilities. The CTs would be capable of operating on either natural gas or syngas. Reclaimed water from Meridian's municipal system would provide the main water supply required for cooling water makeup, steam cycle makeup, and other processes.

The air-blown TRIG™ gasifiers would be based on KBR's fluidized catalytic cracker design. Southern Company, KBR, and DOE have been developing the TRIG™ technology since 1996 at a research facility near Wilsonville, Alabama. At full design capacity, the new gasifiers would use an average of up to 13,800 tpd of lignite coal to produce syngas. The design coal feed rate to each gasifier would be approximately 290 tons per hour (tph). Most of the sulfur and other constituents in the coal would be removed from the syngas before delivery to the gas turbines. Each gasifier would produce the total syngas requirement for a single CT: approximately 425 tph of syngas with a lower heating value of approximately 2,240 British thermal units per pound (Btu/lb). The energy efficiency of the IGCC plant would be approximately 42 percent gross and 29 percent net based on HHV (SCS, 2009).

Among coal gasification technologies, the TRIG™ technology is one of the most cost-effective when using low-quality coal, including lignite, as well as coal with high-moisture or high-ash content. These coals comprise half the proven United States and worldwide reserves. The plant would be designed for operation on lignite coal, and a lignite surface mine would be located immediately northwest, west, and south of the power plant site.

The proposed project would reduce SO_2, NO_x, mercury, and particulate emissions by removing constituents from the syngas. The removal of nearly 100 percent of the fuel-bound nitrogen from the syngas prior to combustion in the gas turbines would result in appreciably lower NO_x emissions compared to conventional coal-fired power plants. The project is expected to remove up to 99 percent of the sulfur and more than 92 percent of the mercury. More than 99.9 percent of particulate emissions would be removed using a rigid barrier filter system (SCS, 2009).

The facility is planned for carbon capture systems sufficient to reduce CO_2 emissions by up to approximately 67 percent by removing carbon from the syngas during the gasification process. This level of CO_2 removal may be nominally identified as *65-percent removal* (or *natural gas equivalence*) because it would result in an average CO_2 emission rate of approximately 800 to 820 pounds per megawatt-hour (lb/MWh), which is nominally equivalent to the CO_2 emission rate from a natural gas-fired combined-cycle unit of approximately 800 to 850 lb/MWh. The CO_2 would be compressed and piped offsite for beneficial use via EOR. The CO_2 pipelines would be another of the project's connected actions. Because the planned CO_2 removal technology has not been commercially demonstrated at a facility like the proposed IGCC power plant, and in light of the anticipated evolving regulatory treatment of CO_2, short-term capture rates could vary from 0 percent (for example, due to a malfunction of the CO_2 compressor) up to the design of 67 percent. Annual average capture rates near 67 percent would be expected, and this design case provides the basis for the estimates in this chapter; however, the tables in this chapter also provide data on emissions and byproduct production rates for a range of CO_2 capture from 50 to 67 percent on an annual average basis.

The proposed project would discharge no process water effluent from the site. Ash generated by the gasifiers would be stored onsite and would be evaluated for beneficial use at the adjacent mine or for placement in an onsite management unit. Beneficial use of the ash could include industrial processes such as building roads, soil amendment, or for other uses as approved by **the Mississippi Department of Environmental Quality (**MDEQ**)**. Commercial grade anhydrous ammonia and sulfuric acid (H_2SO_4) would be recovered as byproducts and marketed. The markets for both ammonia and H_2SO_4 are well established. With regard to the H_2SO_4 market, purchasers of this byproduct would be available regionally. Moreover, in the event that market conditions existed where supply exceeded demand, H_2SO_4 would be sold at below-market rates to large users, such as the phosphate industry that normally generates H_2SO_4 onsite from elemental sulfur. If marketing of the anhydrous ammonia produced at the facility were not possible, the ammonia would either be used at this and other Southern Company generating plants in their SCR air emission control systems, or it would be recycled within the gasifier for oxidation and converted to nitrogen (N_2) and hydrogen (H_2) or water (H_2O).

Figure 2.1-**6** provides the arrangement of the proposed IGCC power plant equipment on the site. Key equipment and facilities are identified. Note that some onsite facilities would be associated with the surface lignite mining operation, not the power plant itself; prominent among these would be permanent coal handling facilities, roads for hauling lignite to the point of transfer to the power plant, and warehouse, shop, and office buildings. A

small portion of the initial mine area and **a** mining-related sedimentation pond would occupy land within the site, as discussed subsequently.

Another prominent feature shown in Figure 2.1-6 is a surge pond, which would store reclaimed water for use in the power plant. This pond was initially located on the portion of the site east of MS 493. As discussed in Subsection 2.7.4.3, Mississippi Power has relocated it as shown, primarily to reduce impacts to onsite streams.

Based on the layout shown in Figure 2.1-**6**, Figure 2.1-**7** presents a computerized rendering of the proposed facilities superimposed on an aerial photograph of the site that faces generally southwest. The following subsections provide details of the key processes within the gasification and electrical power generation facilities.

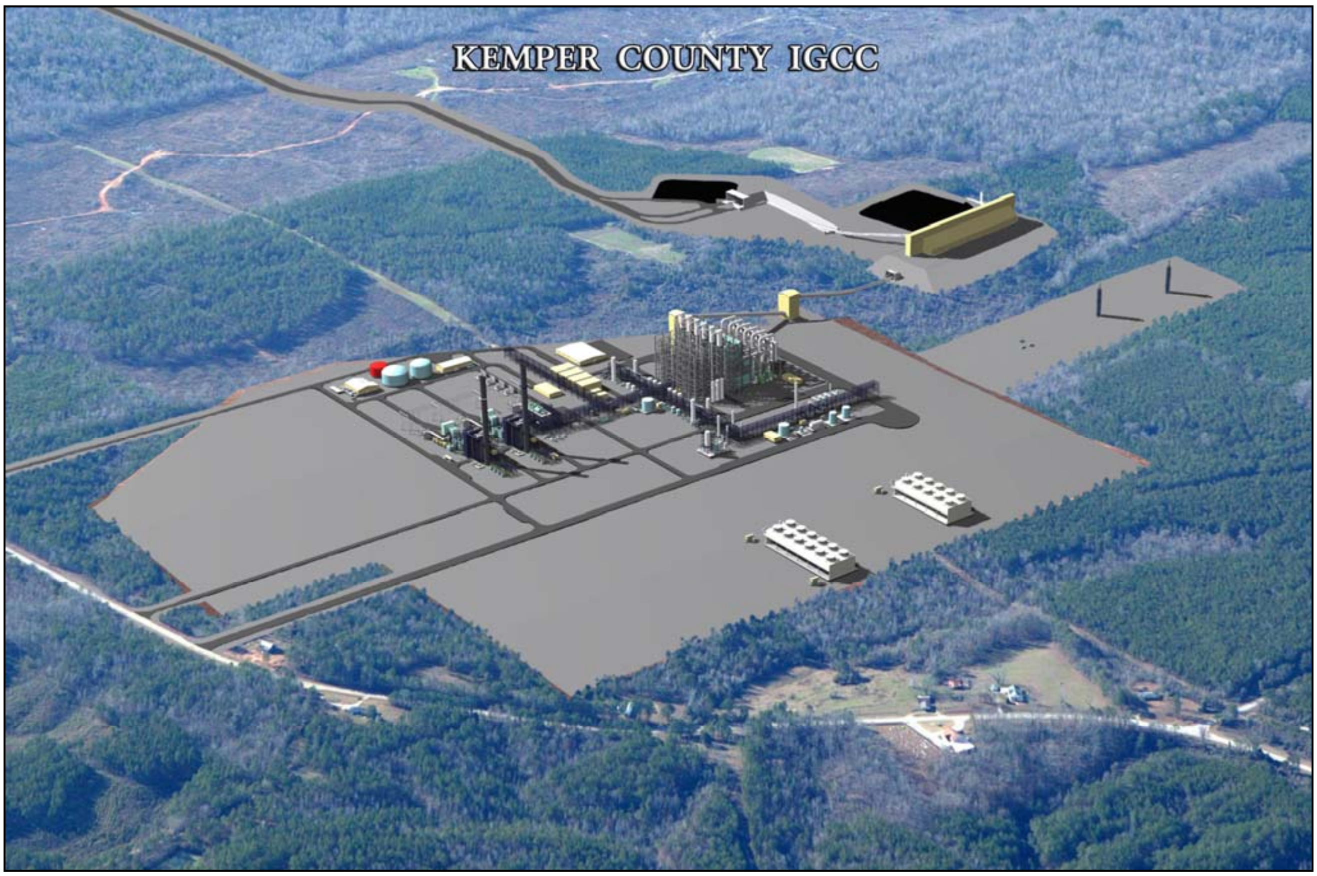

Figure 2.1-7. Concept Rendering of the Proposed IGCC Project Facilities
Source: SCS, 2009.

2.1.2.1 Lignite Receiving, Storage, Handling, and Feeding

The design of the IGCC plant is based on the use of lignite coal that would be mined at the adjacent surface mine (see Section 2.2). Off-road mining trucks would deliver lignite to a covered truck dump hopper, located adjacent to the power plant. An apron feeder would feed the lignite into the mill for primary crushing/sizing. A conveyor would transfer the lignite to the secondary sizer. The crushed lignite would then be conveyed to the covered lignite barn and distributed in the barn by a traveling belt tripper. An emergency lignite pile would be

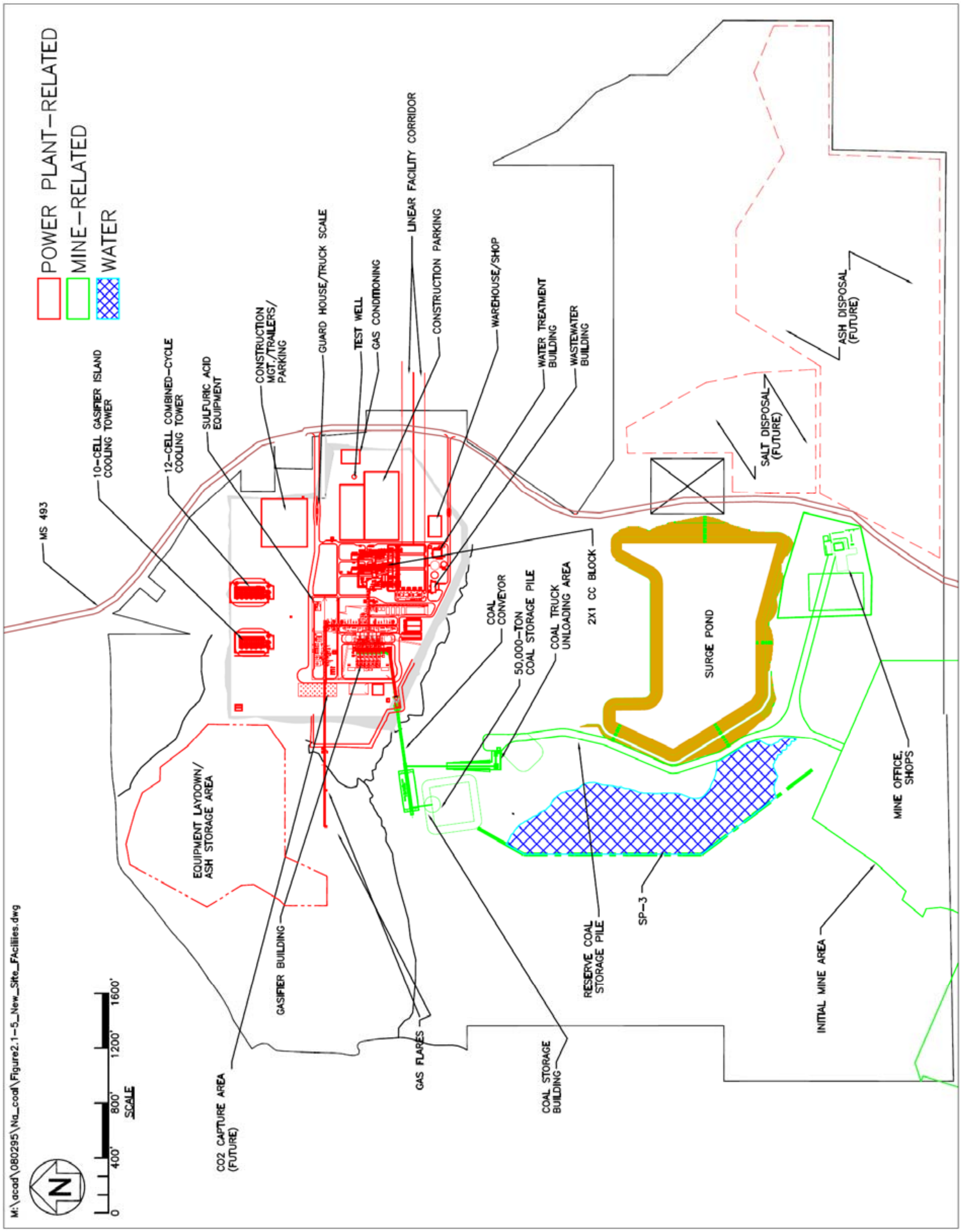

Figure 2.1-6. Planned Arrangement of Equipment and Facilities on the Kemper County IGCC Project Site

Sources: SCS, 2009. NACC, 2009. ECT, 2009.

located outside the barn. A redundant series of conveyors would reclaim the lignite from the barn with rotary plow feeders and convey the lignite to a transfer structure, which would load another set of conveyors and continue to the tripper conveyors to transfer the lignite from the mine into six silos located in the power plant.

At the power plant, lignite from the silos would be fed into a crusher and then into a fluid-bed dryer, where it would be dried to the specified moisture content. The lignite coal leaving the fluidized bed dryer would flow into the coal mill where it would be pulverized, and a conveying gas would carry the pulverized coal to the pulverized coal baghouse. The fluid-bed dryer exhaust gas would be sent to a multistage cyclone where any elutriated solids would be separated from the gas stream. These solids removed from the gas would combine with the elutriated solids leaving the coal mill and flow into the pulverized coal baghouse. The exhaust gas exiting the multistage cyclone would be sent to a venturi scrubber, where the gas would be cooled with cold water to condense the moisture from the wet coal. The condensed water would be used elsewhere in the gasification process. The cooled, saturated gas would be heated and sent back to the fluid-bed dryer. Any entrained coal fines in the multistage cyclone exhaust would be captured by the venturi scrubber and separated from the water by a belt filter press. The coal fines from the belt filter press would be added to the pulverized coal feed.

The pulverized coal baghouse would be located directly above the pulverized coal silo. The pulverized coal would be separated from the conveying gas and dropped into the pulverized coal silo. The gas exiting the baghouse would be sent through a fan and back to the coal pulverizer.

2.1.2.2 Transport Integrated Gasification (TRIG™)

Each of the two gasifiers would consist of an upright looped set of piping with a total height of approximately 185 ft (Figure 2.1-**8**). Lignite, which would be injected near the top of the mixing zone, and air, which would be fed into the bottom of the mixing zone, would mix with gasifier ash recirculated through the J-valve from the standpipe. Approximately 435 tph of compressed air would be supplied to the gasifier during operation. Oxygen in the air would be consumed by carbon present in the recirculating ash, forming primarily carbon monoxide (CO). This reaction would release the heat required to maintain vessel temperature. The hot recirculating ash would heat the lignite rapidly, minimizing tar formation, and the lignite would be converted to syngas.

Syngas and gasification ash would pass from the mixing zone up the riser and then to staged solids separation devices where larger, denser particles would be removed in stages and collected into the standpipe. The combined ash would pass down the standpipe and through the J-valve into the mixing zone, while the syngas would continue to the gas coolers and filter devices. Since a vast majority of the solids would remain

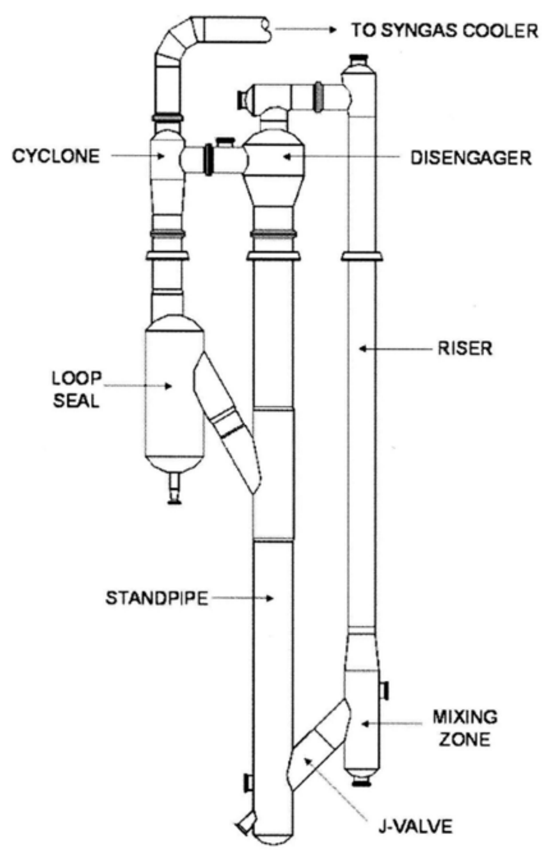

Figure 2.1-8. Side View of a Gasifier
Source: SCS, 2008.

in the gasifier, gasification ash would be removed periodically from the gasifier to maintain constant gasifier bed inventory.

During gasifier startup, natural gas and/or fuel oil-fired burners would be used to heat the gasifier until reaching a sufficient temperature to initiate lignite feed. Because the exhaust gas from the burners would not be combustible, the exhaust gas would be vented to the startup stack instead of the flare. Once the gasifier reached a sufficient temperature during startup, the injection of lignite would begin, and the airflow would be reduced until the atmosphere in the gasifier formed a reducing environment rather than an oxidizing environment. Subsequently, the lignite would be gasified, and syngas would be produced. Because the flow of syngas would initially be insufficient to send to the CT, it would first be sent to the flare and burned after passing through particulate and mercury collection systems. As the gasifier reached a syngas production level sufficient to support the operation of the CT, the syngas would be routed through acid gas removal (AGR) systems and would then be diverted from the flare to the turbine.

The duration of the startup sequence could vary significantly, depending on a number of factors including the starting temperature of the gasifier. During a cold start, approximately 18 hours would elapse prior to sending syngas to the gas turbine due to the time required to heat the gasifier refractory. The typical startup period would include approximately 16 hours of exhausting gas through the startup stack and approximately 2 hours of combusting syngas in the flare.

2.1.2.3 High-Temperature Syngas Cooling

Syngas leaving each gasifier cyclone would pass via piping to a high-temperature syngas cooler that would lower the gas temperature before it enters a particulate filter system. The heat transferred would be used to raise the temperature of high-pressure superheated steam.

The syngas cooler would consist of three stages: an evaporator, a superheater, and an economizer. The evaporator would include a natural circulation steam drum operating at above steam turbine inlet pressure and at saturated temperature. The steam raised in the evaporator would be passed to a superheater that would heat the steam to the steam turbine inlet temperature. This steam would be mixed with superheated steam exiting the combined-cycle unit's HRSG (Subsection 2.1.2.9) before passing into the steam turbine. Boiler feedwater would enter the economizer and would be heated to near saturation before entering the steam drum.

2.1.2.4 Particulate Collection

After cooling, syngas would pass via piping to the particulate filter system for final particulate removal. The filter system would use rigid, barrier-type filter elements to remove essentially all of the particulate matter (PM) in the syngas stream. Pulses of recycled, filtered syngas would be used to remove accumulated PM from the filters. Downstream of each filter element, a device would safeguard the CT from particulate-related damage in the event of a filter element failure.

Each of the two filter systems per gasifier would remove approximately 12.5 tph of PM from the syngas stream. The concentration of PM in the cleaned syngas is expected to be less than 0.1 part per million (ppm) by weight. The syngas streams would exit the filter vessels and flow to the low-temperature heat recovery system. The removed PM (fine ash) would be cooled and depressurized to ambient conditions before leaving the gasification facilities. This fine ash would then be managed as discussed in Subsection 2.6.3.2.

2.1.2.5 CO_2, Sulfur, and Mercury Removal

Carbon, sulfur, and mercury removal would begin in the low-temperature gas cooling section of the IGCC plant. To remove carbon from the syngas in the AGR system, approximately 90 percent of the CO in the syngas must first be converted to CO_2. This step would occur in a water gas shift (WGS) reactor, according to the equation $CO + H_2O \leftrightarrow CO_2 + H_2$.

The syngas leaving the gasifier and entering the WGS would not contain enough water to convert the necessary CO to CO_2. So, the syngas must first pass through a saturation column where the hot syngas would evaporate warm water, increasing the water content of the syngas. This saturation column would also remove essentially all chlorine and fluorine from the syngas. The purge water from the saturation column would go to the sour water system for removal of any dissolved gases. The syngas would flow through two WGS reaction vessels in series, producing a significant amount of heat, which would raise the temperature of the syngas. This heat would be recovered and used elsewhere in the gasification process and the syngas cooled to approximately 400 degrees Fahrenheit (°F).

To remove sulfur in the acid gas system, the syngas would then enter a carbonyl sulfide (COS) hydrolysis reactor **if sulfur levels require this step. T**he sulfur removal process operates best when COS in the syngas is first converted to hydrogen sulfide (H_2S). After the COS hydrolysis reactor, the syngas would pass through the low-temperature gas cooling area before entering a water scrubber for final ammonia removal via condensation. The syngas would then flow to the AGR process for H_2S and CO_2 removal. In this process, the syngas would be contacted with a solvent to remove H_2S from the syngas stream. **To improve the efficiency of the AGR process, the solvent would be kept below ambient temperatures. To maintain the solvent's operating temperature, a conventional vapor-compression cycle refrigeration system would be used.** The H_2S in the solvent would be stripped from the solvent and converted to concentrated H_2SO_4. The stripped solvent would be returned to the sulfur removal process. After the H_2S removal step, the syngas would then flow through a second solvent contactor where the CO_2 is removed from the syngas.

Following the H_2S and CO_2 removal processes, the syngas would be heated and then flow through a reactor containing alumina-based metal sulfide **or sulfide activated carbon** to remove mercury from the syngas. After mercury removal, the syngas would be heated to the temperature required for entering the gas turbine. Upon exiting the low-temperature gas cooling system and mercury removal, approximately 88 percent of the sweet syngas would flow to the CT, while the remaining 12 percent would pass to the syngas recycle system. Some of the recycled syngas would be sent to the pulse-gas reservoirs and used to pulse clean the high-temperature, high-pressure filters, while the remainder would be used for aeration in the gasifier and as an oxygen-deficient gas supply for auxiliary processes.

2.1.2.6 Sulfur and CO_2 Recovery

Sulfur removed in the AGR system would be recovered in the wet gas sulfuric acid (WSA) process. The acid gas containing H_2S would be converted to SO_2 with air in an incinerator. Steam would be generated in a waste heat boiler, and excess air, SO_2, and other combustion products would be carried through a catalytic converter where SO_2 would be catalytically oxidized into sulfur trioxide (SO_3). Finally, SO_3 would be condensed as concentrated H_2SO_4 in the WSA condenser.

Prior to compression the removed CO_2 stream must be dried to meet pipeline specifications. This could be achieved in several ways, but the facility would plan to accomplish this by passing the removed CO_2 stream through a standard gas desiccant drying unit. To meet pipeline specifications for delivery for EOR, the AGR process would be designed to ensure the purity of the CO_2 stream was approximately 99 percent with less than 1 percent inert gases. The CO_2 would then be compressed to the 2,100 pounds per square inch (psi) required to enter the pipeline. In the event the CO_2 is not placed into the pipeline, the CO_2 stream would be vented to the atmosphere through the IGCC stacks **except during periods of startups and shutdown of the AGR process, when the CO_2 stream would be vented through dedicated AGR vent stacks**.

2.1.2.7 Sour Water Treatment and Ammonia Recovery

As the syngas is cooled in the low-temperature gas cooling section described previously, water in the syngas would condense out. This water would remove most of the ammonia in the syngas as well as lesser amounts of CO_2, CO, and H_2S. This aqueous mixture would be removed from the syngas stream in a knockout drum and passed to the sour water treatment plant. The sour water treatment and ammonia recovery unit would treat approximately 275 gallons per minute (gpm) of water. The combined water flow would collect in a wastewater drum before passing to an activated carbon bed to remove **mercury and** organic material.

Next, the sour water would be heated and passed to the steam-heated H_2S stripper where H_2S, hydrogen cyanide (HCN), CO, and CO_2 would be released, recompressed, and sent to the AGR section of the process. The water from the H_2S stripper would discharge to the steam-heated ammonia stripper to produce a concentrated ammonia solution. The water drawn from the bottom of the ammonia stripper would be sufficiently pure for plant reuse.

The concentrated ammonia solution would be processed further in an additional steam-heated stripper to increase the ammonia concentration to approximately 99.5 percent. The water drawn from the bottom of this column would also be sufficiently pure for plant reuse. The ammonia produced would be commercial-grade anhydrous ammonia. Excess anhydrous ammonia could be sold in the commercial market.

Provisions would be made to recycle the ammonia to the mixing zone of the gasifier for destruction if removal of the anhydrous ammonia by truck was to be delayed and the storage tank was approaching full. The recycling of ammonia would be straightforward. The sour water treatment plant would operate at higher pressure, so the ammonia would be at a pressure sufficient for it to be in a liquid state. Therefore, it would need only to be pumped to the gasifier and would enter the gasifier in the oxidizing zone for decomposition.

2.1.2.8 Flare

The IGCC power plant's gasification component would be equipped with one or two flare derricks. The flares would be used for combustion of syngas during startups, shutdowns, and plant upsets (e.g., a sudden shutdown of the combined-cycle unit's gas turbine) and to combust exhaust gases that could not be safely vented to the atmosphere during process upsets and emergencies. The flares might also be used to continuously combust smaller exhaust gas streams from various process vent streams associated with the gasification process.

The flare derricks would be approximately 150 ft tall and would be equipped with multiple natural gas-fired pilots with a total nominal rating of 6 million British thermal units per hour (MMbtu/hr). These pilots would operate continuously to ensure the flare is ready to combust syngas immediately in the event of a plant upset. While the pilots are operating, a flame would rise only a few feet above the top of the flare derricks. As discussed in Subsection 2.1.2.2, during gasifier startup, the flow of syngas would initially be insufficient to send to the CT, and it would first be sent to the flare. The typical startup period would include approximately 2 hours of combusting syngas in the flare. The height of the flame above the flare derrick would steadily increase during the startup period reaching a height of approximately 150 ft. Shutdowns would result similarly but in reverse. There would be approximately 20 startup and shutdowns per gasifier annually during the demonstration phase.

During a plant upset when the CT is operating at full load and syngas is safely routed to the flare, the **visible** flame height would rise approximately 200 to 300 ft above the top of the flare derricks. **In contrast, t**he **pilot** flames would be nearly invisible during daylight hours, except for shadows from heat effects, while a bluish purple flame would be visible at night. It is expected that periods of operating the flare at full load (i.e., due to plant upsets) would be brief and infrequent, lasting approximately 2 hours. CTs firing natural gas might be expected to experience an upset approximately once or twice per year. Part of the demonstration project would include defining and minimizing the number of upset on this syngas fired CT. Figure 2.1-**9** is an illustration of a typical flare derrick with a single flare, similar to what is planned for the proposed project.

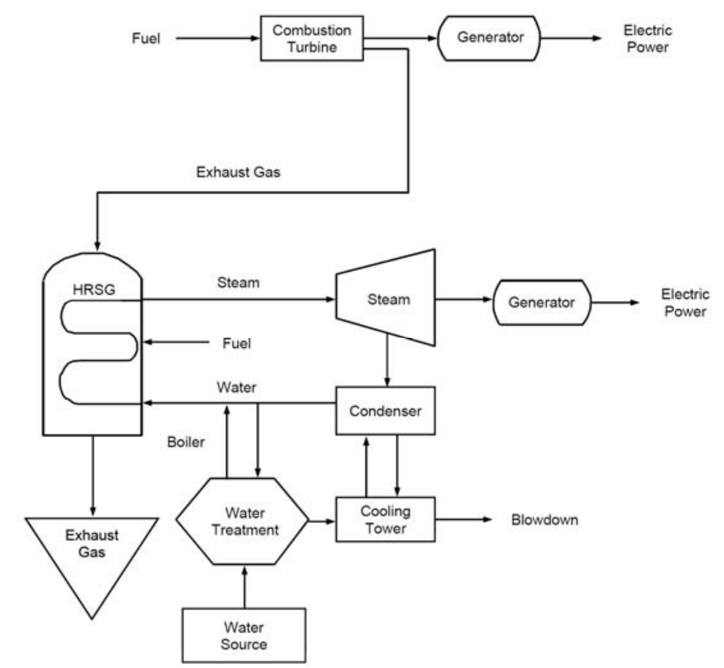

Figure 2.1-10. Conceptual Schematic of a Combined-Cycle System

Source: ECT, 2008.

Figure 2.1-9. Typical Flare Derrick with a Single Flare

Source: SCS, 2009.

2.1.2.9 Combined-Cycle Systems

The proposed combined-cycle system would include two CTs, each with a dedicated HRSG, and associated auxiliary, control, and other support systems and facilities. The heat input ratings of the two models are almost identical. The two CT/HRSG trains would supply steam to a single steam turbine. This arrangement of equipment is referred to as a 2-on-1 configuration, a standard configuration in the power industry. Figure 2.1-**10** provides a schematic of a combined-cycle system, showing a CT, an HRSG, a steam turbine, and other key components.

The CTs would convert energy stored in the syngas (or natural gas) into mechanical energy using compressed hot gas (i.e., air and products of combustion) as the working medium. Each CT would deliver mechanical energy using a rotating shaft to drive an electrical generator, thereby converting a portion of the mechanical output to electrical energy. Initially, ambient air would be filtered and then compressed by the CT's compressor section, which would increase the pressure of the combustion air stream and also raise its temperature. The compressed combustion air would then be combined with syngas, which would be ignited in the CT's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases would expand and drive the turbine section to produce rotary shaft power and electricity.

The heat in each CT's exhaust gases would be used to generate steam from water in an HRSG. The HRSG would be equipped with natural gas-fired duct burners to boost power generation capability during periods of peak demand. The steam would be used to drive a steam turbine and generator to produce additional electricity.

High-pressure superheated steam from the syngas cooler and the HRSG would enter the steam turbine. Steam exhausted from the high-pressure portion of the steam turbine would be reheated in the HRSG, expanded through the intermediate- and low-pressure portions of the steam turbine, and then condensed for reuse in the steam cycle of the HRSGs.

2.1.2.10 Cooling Towers and Makeup Water Pond

The IGCC facility would include two multi-cell cooling towers. The combined-cycle unit would be supported by a 12-cell wet mechanical-draft cooling tower to provide the cooling necessary to condense the steam that exhausts from the steam turbine and generator as well as provide additional equipment oil cooling. A water-cooled steam surface condenser would also be used, and the condensate would be collected in the hot well of the condenser and pumped back to the HRSG. Cooling water would be supplied to the surface condenser from the cooling tower. The gasifier system would be equipped with a separate, 10-cell wet mechanical-draft cooling tower to provide cooling for the gasifier equipment and processes. Multiple heat exchangers would be used to transfer the heat from the closed loop gasifier cooling water to the cooling tower circulating water.

To provide makeup supply water to the cooling system to replace water lost through evaporation, reclaimed effluent from two publically owned treatment works (POTWs) in Meridian, Mississippi, would be used. To provide for weather-related events and accommodate the seasonal variability of reclaimed water flow from the Meridian POTWs, Mississippi Power would construct an approximately 1,000 acre-foot (ac-ft) surge pond on the plant site to manage the supply of makeup water. If inadequate supplies of makeup water were available from the POTWs, nonpotable ground water from onsite wells would supplement the surge pond as necessary. The planned location of the surge pond on the plant site **in an area south of the power block** is indicated on Figure 2.1-**6**. The power plant's water supply plans are discussed further in Subsection 2.5.2.

2.1.2.11 Beneficial Use of CO_2 for EOR and Geologic Storage

CO_2 captured from the Kemper County IGCC power plant would be compressed onsite to approximately 2,100 psi. At this pressure the compressed CO_2 is in a dense phase, which means it behaves as a liquid. This *liquid* CO_2 would be delivered to underground CO_2 pipeline**s**. The CO_2 would be transported via th**ese** pipeline**s** to a maturing oil field, where it would be injected by the owner of the oil field under a Class II Underground Injection Control (UIC) permit for EOR. CO_2 EOR is the process of injecting CO_2 into an oil reservoir for the purpose of producing additional quantities of oil from a mature oil field. Generally speaking, CO_2 EOR is conducted after primary (initial extraction) and secondary (waterflood) operations are complete or near complete. The oil remaining in the reservoir after primary and secondary operations is immobile due to several factors, including the surface tension that exists between the sand grains in the depleting formation and the oil, increased viscosity of the oil, and reduced pressure in the reservoir. The injection of CO_2 (typically injected in the dense phase) increases the reservoir pressure, reduces the surface tension, and reduces the viscosity, which results in the ability of the oil to become mobile and be recovered. The oil and CO_2 actually mix and have the possibility of becoming fully miscible in some reservoirs depending on the specific gravity of the oil, temperature of the reservoir, and reservoir pressure (SCS, 2009).

The primary benefit of CO_2 injection is to increase the pressure in the reservoir. Regardless of whether the oil and CO_2 are fully miscible, the oil and CO_2 mixture flow through the reservoir together and are brought to the surface together. The pressure decreases in this CO_2/oil mixture as it is brought to the surface. As a result, the CO_2 and oil begin separating. The majority of the separation is due to the CO_2 changing from the dense liquid phase back to a gas and breaking out of the oil. At the surface, the oil and CO_2 are separated through a series of vessels where the pressure is reduced even further. Heat is added to complete the separation of the oil and CO_2. The CO_2 is not vented but is captured, recompressed, and injected back into the reservoir, and the cycle, known as a sweep cycle, begins again. The oil is stored in surface tanks at near atmospheric pressures. The oil tanks are equipped with vapor recovery units that capture any minor amounts of CO_2 that remained in the oil after the separation process. The CO_2 injected in the oil recovery operations would be managed in this closed loop system. On an ongoing injection volume basis, a percentage of the CO_2 would be physically or chemically trapped in the geological formation and stay in the reservoir permanently.

The majority of the CO_2 in EOR is sequestered by physical means. The CO_2 essentially replaces the oil, natural gas, and water volumes or get trapped in small pore spaces that are not interconnected to the effective pore space. Additionally, capillary forces also trap some of the CO_2. During each sweep cycle, more than approximately 50 to 67 percent of the injected CO_2 injected returns with the produced oil, while the CO_2 in the produced oil would be recycled and reused in the next sweep cycle in a closed loop (IPCC, 2005). Because this would be a closed system, during normal operations no CO_2 would be released to the atmosphere. After each sweep cycle, additional CO_2 would become sequestered in the geologic formation. Minute equipment leaks could occur and CO_2 could be vented during EOR plant upsets. The volume of CO_2 released in these incidents would be very small (less than 1 percent of the total of injected CO_2).

CO_2 captured from the proposed Kemper County IGCC Project would be transported via pipeline for EOR at existing oil fields in Mississippi. Mississippi Power is currently negotiating with **more than one** owner and operator of existing oil fields to sell CO_2 from the project. **Accordingly, more than one maturing oil field, including** fields located in the Eutaw, Tuscaloosa, and Hosston formations**, could receive CO_2 from the project.** The CO_2 could be injected from 5,000 to 12,000 feet below land surface (ft bls). Because the existing oil fields already conduct EOR activities, CO_2 received from the IGCC project would displace the oil field owner's current sources of CO_2, including naturally occurring CO_2 from the Jackson Dome.

2.2 CONNECTED ACTIONS

While the proposed Kemper County IGCC Project would consist of the gasifiers, syngas cleanup systems, two CT/HRSGs, a steam turbine, and other power plant facilities, the complete project would also include the construction and operation of a contiguous surface lignite coal mine, a reclaimed effluent supply pipeline, a natural gas supply pipeline, associated transmission lines (and substations), and CO_2 pipelines, as connected actions. Figure 2.2-1 shows the locations of these facilities; each is described in the following subsections. The pipelines and transmission lines are sometimes collectively referred to as *linear facilities*. Figure 2.2-2 provides a closer look at these facilities in and around Meridian.

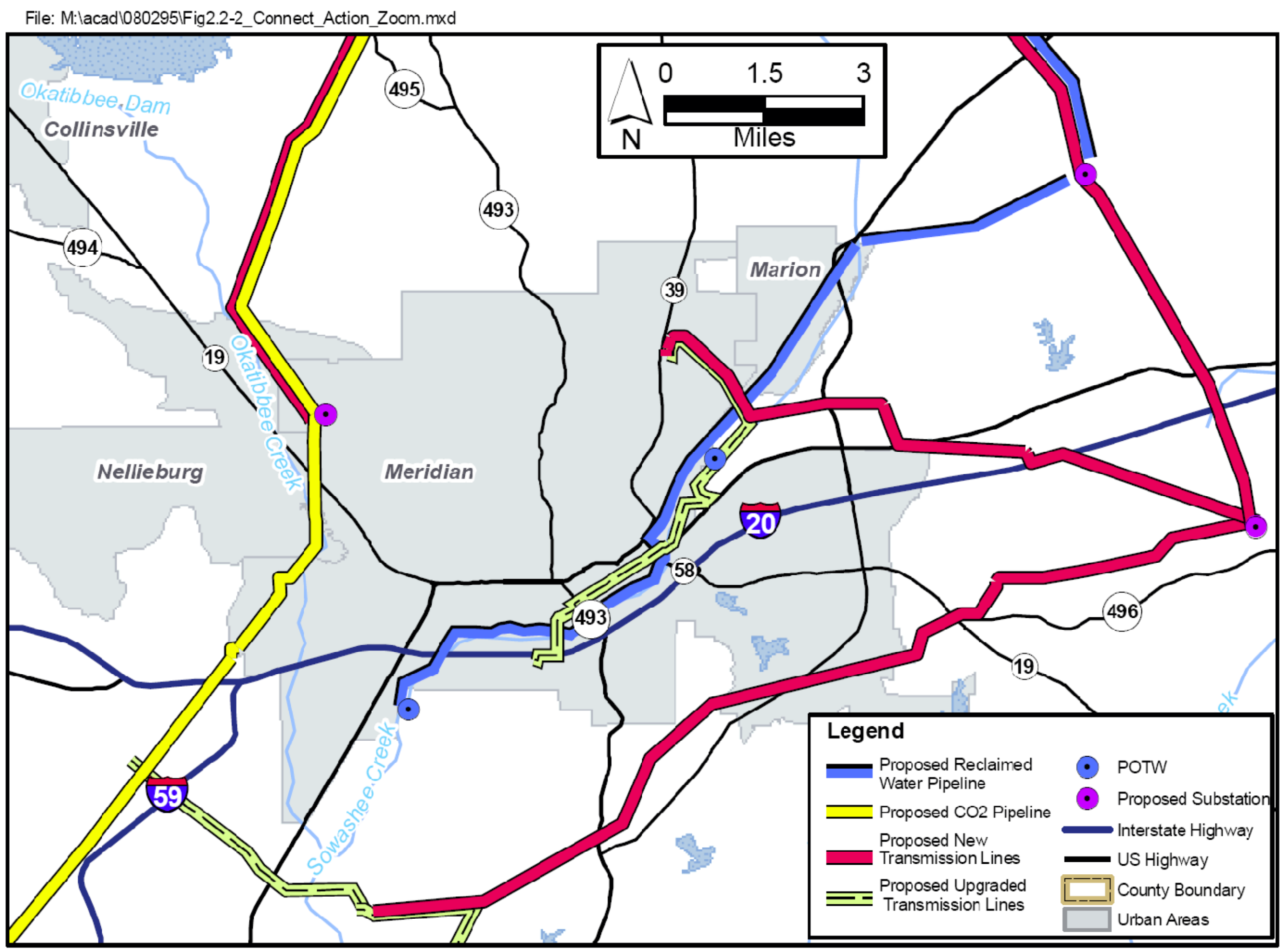

Figure 2.2-2. Proposed Connected Actions in the Vicinity of Meridian

Sources: U.S. Census, 2000. MARIS, 2008. ECT, 2009.

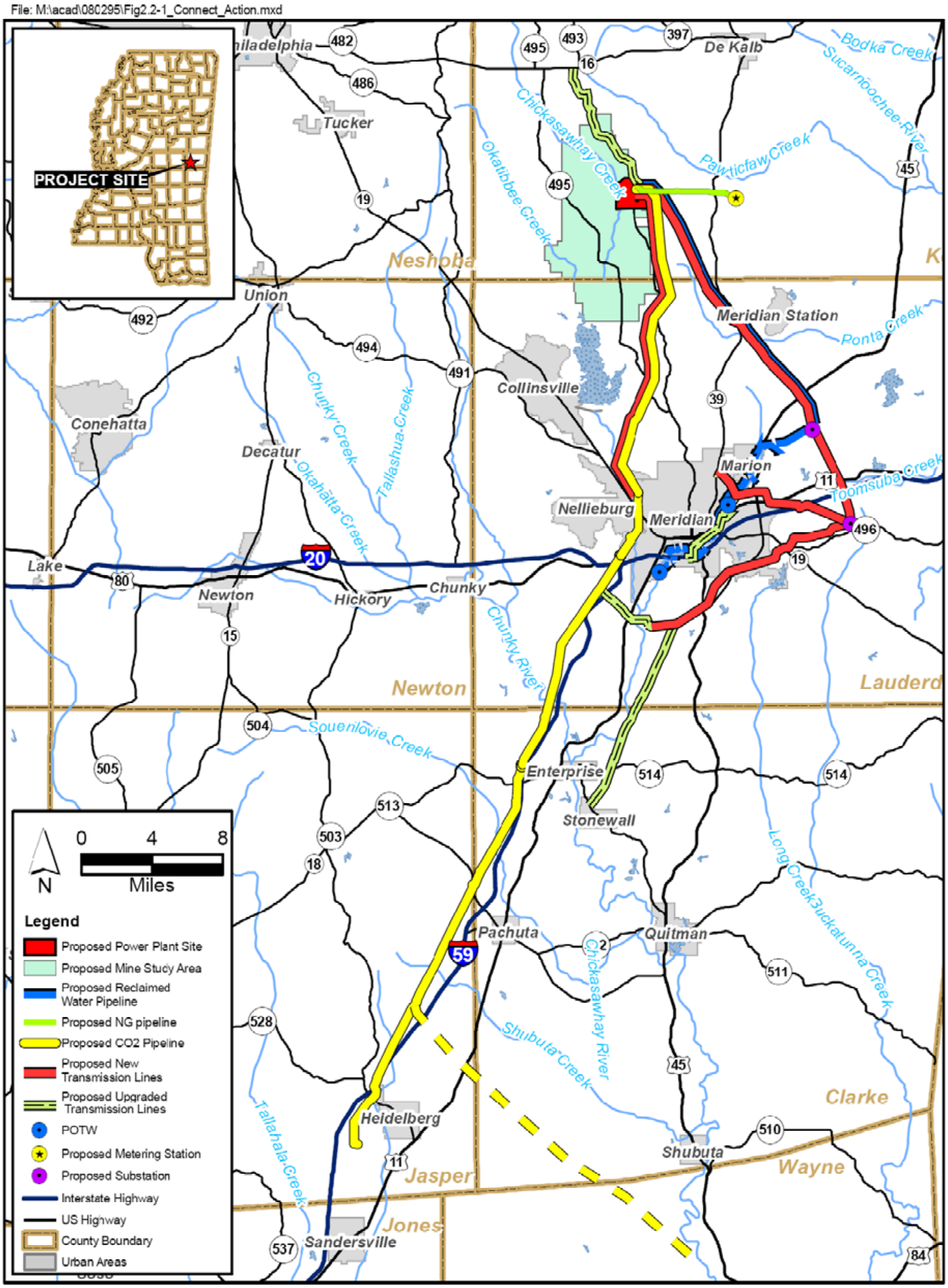

Figure 2.2-1. Locations of Proposed Connected Actions

Sources: U.S. Census, 2008. MARIS, 2008. ECT, 2009.

2.2.1 SURFACE LIGNITE MINE

The proposed lignite mine (known as the Liberty Fuels Mine) would be located adjacent to the power plant site (see Figures 2.2-1 and 2.2-3). Mining would occur on blocks of land within an approximately 31,000-acre area (mine study area), including approximately 1,400 acres within the boundary of the power plant site. The mine would be designed, permitted, constructed, and operated by NACC for the dedicated purpose of providing the primary source of fuel for the IGCC project. Approximately 4.3 million tons per year (tpy) of lignite would be produced to fuel the IGCC facilities described previously for up to 40 years (NACC, 2009).

Approximately 12,**275** acres within the mine study area would be mined or disturbed to provide a 40-year supply of the primary lignite fuel to be utilized at the IGCC plant. To facilitate this production, the mine would operate up to 24 hours per day, 7 days per week, and potentially every day of the year. The mine operations would include clearing the land of vegetation, structures, and rubble; uncovering and extracting the lignite; operation of lignite handling facilities; regrading and reclamation **of mined and disturbed areas**; construction and use of haul roads; and utilization of maintenance facilities and vehicles.

The locations within the mine study area where lignite would be extracted and mine facilities would be constructed will depend on NACC's ability to negotiate for properties or mineral rights from landowners and permit application evaluations conducted by USACE and the Mississippi Department of Environmental Quality (MDEQ). Because the power of eminent domain could not be exercised, only properties whose owners consent to sell or lease could become locations where lignite is extracted or mine facilities constructed. Property and/or mineral rights in the mine study area acquired by NACC would be initially held by Kemper Natural Resources, LLC, a subsidiary of Mississippi Power. It is anticipated that Mississippi Power would, through its subsidiary or directly, own the property rights in the mine, and NACC would construct and operate the mine under a management fee arrangement. The WMA located to the north of Okatibbee Lake (i.e., the Okatibbee WMA) is not proposed to be part of the mine, and NACC is not seeking any mineral rights or use approvals from the WMA; no physical disturbance of the WMA is proposed. With respect to MDEQ and USACE, both agencies have the authority to prohibit mining disturbance of portions of the mine study area possessing certain environmental or other attributes under the Surface Mining Control and Reclamation Act (SMCRA) in the case of MDEQ and Section 404 of the CWA in the case of USACE. Purchase negotiations with landowners and permit application evaluations by MDEQ and USACE would likely continue throughout the projected 40-year operating period.

Prior to any land disturbance activities associated with the mine, NACC would have to obtain certain regulatory approvals from **MDEQ in addition to a mine operating permit under the state's SMCRA-implementing regulations. Principal among these is an NPDES permit to discharge controlled water from the active mining areas. The NPDES permit would limit concentrations of pollutants allowed in any discharges from the mine based upon technology-based, water quality-based, aquatic life criteria-based, or total maximum daily load (TMDL) effluent standards. Chapter 4 explains how these limits affect water quality impacts, and Chapter 5 describes typical pollution prevention and mitigation measures that would be incorporated into the NPDES permit as conditions of approval, including compliance monitoring locations and parameters.**

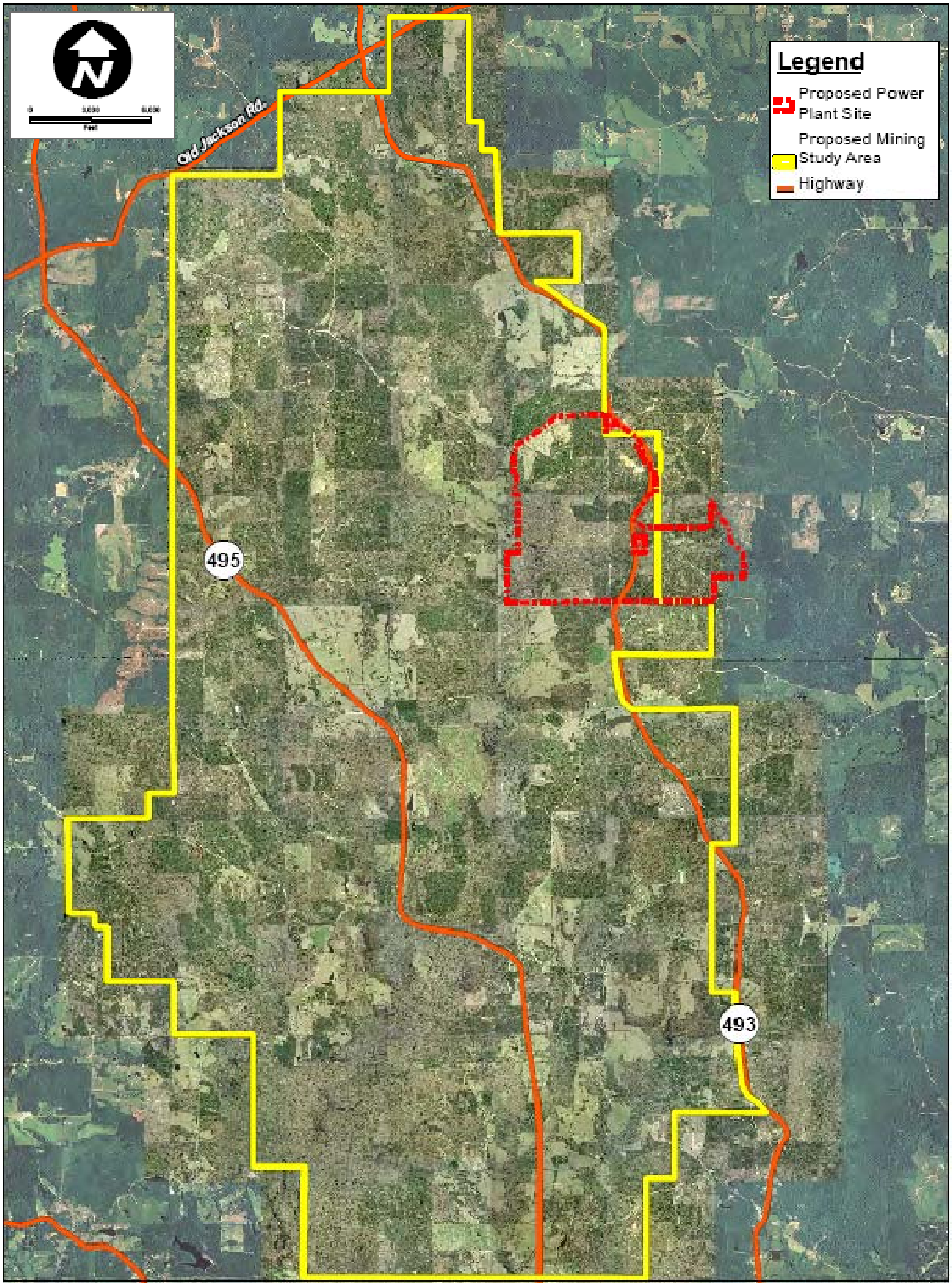

Figure 2.2-3. 2008 Aerial Photograph of Mine Study Area and Power Plant Site
Sources: NACC, 2008. SCS, 2008. ECT, 2009.

Due to the schedule for the construction of the mine, mine equipment, support structures, and lignite handling facilities, the first 6 to 8 months of operation of the IGCC, which would primarily encompass the startup and mechanical checkout of the facilities, would be fueled with lignite trucked from NACC's Red Hills Mine in Choctaw County (see Subsection 2.4.1).

There are two types of mining: underground and surface. Based on thickness and layering of the lignite seams, the composition of the overburden, and the energy content of the lignite, surface mining was determined by the owner of the proposed mine, NACC, to be the only practical mining method. Surface mining would maximize the recovery of the economical reserves (NACC, 2008).

2.2.1.1 General Description of the Surface Lignite Mine

Mining would result in two types of landscape disturbance. Actual mining—the uncovering and extraction of lignite—would disturb between 195 and 375 acres per year for up to 40 years, or a total of up to **10,225** acres or 36 percent of the mine study area. The second type of landscape disturbance would result from the installation of facilities and structures supporting the mining operation. Facilities would include **the** lignite handling facilities, office, warehouse, mobile equipment maintenance shop, fuel farm complex, dragline assembly area, entrance and internal mine haul roads, employee and equipment parking areas, and electrical substations and distribution lines. Support structures would include: (a) diversion channels (DIV) to reroute rainfall runoff from undisturbed areas and existing streams away from and around active mining areas; (b) stormwater collection channels (CC) to collect runoff from mined or disturbed areas and route these flows into; (c) water treatment (i.e., sedimentation) ponds (SP) designed to treat water to meet **the NPDES permit** effluent limitations; and (d) flood protection levees intended to either contain runoff from disturbed lands or protect active mining areas from flooding. Up to 800 acres would be required for the mine support structures, with another 320 acres required for the mine support facilities. **Up to 930 additional acres would be disturbed but not mined, resulting in a total potential disturbance of up to 12,275 acres.**

Following lignite removal, approximately 275 acres per year of mined land would be graded to the approximate premining land surface elevations and planted with various types of vegetative cover. Physical completion of land reclamation would occur approximately 3 years after lignite extraction. Upon completion of mining operations, all mine support structures and facilities would be demolished and reclaimed as well. **Under the MDEQ SMCRA Regulations, lands disturbed by mining activities must be reclaimed to standards that address topsoil, surface water quality, surface water quantity, sedimentation and siltation, acid-forming and toxic-forming materials (AFM and TFM), ground water quality, and ground water quantity, among others.**

Preapplication consultations between the mine operator (NACC) and DOE, USACE, MDEQ, U.S. Fish and Wildlife Service (USFWS), and U.S. Environmental Protection Agency (EPA) conducted in 2008 and 2009 have resulted in the preliminary conceptual mine plan shown in Figure 2.2-4 (see Section 2.7 for a description of the alternatives evaluated). As shown in Figure 2.2-4, eight mine blocks labeled A, B1, B2, C, D, E, F, and G have been identified as the lignite extraction areas within the mine site, with the overall advancement of mining proceeding sequentially from mine block A during the initial years **through** mine block G **in** the final years of mining.

Generally, mine blocks would be sized in lengths of 1 mile or so to allow mining to occur in long rows. For example, in the case of the conceptual plan initial mine block A, the dragline and other mining equipment

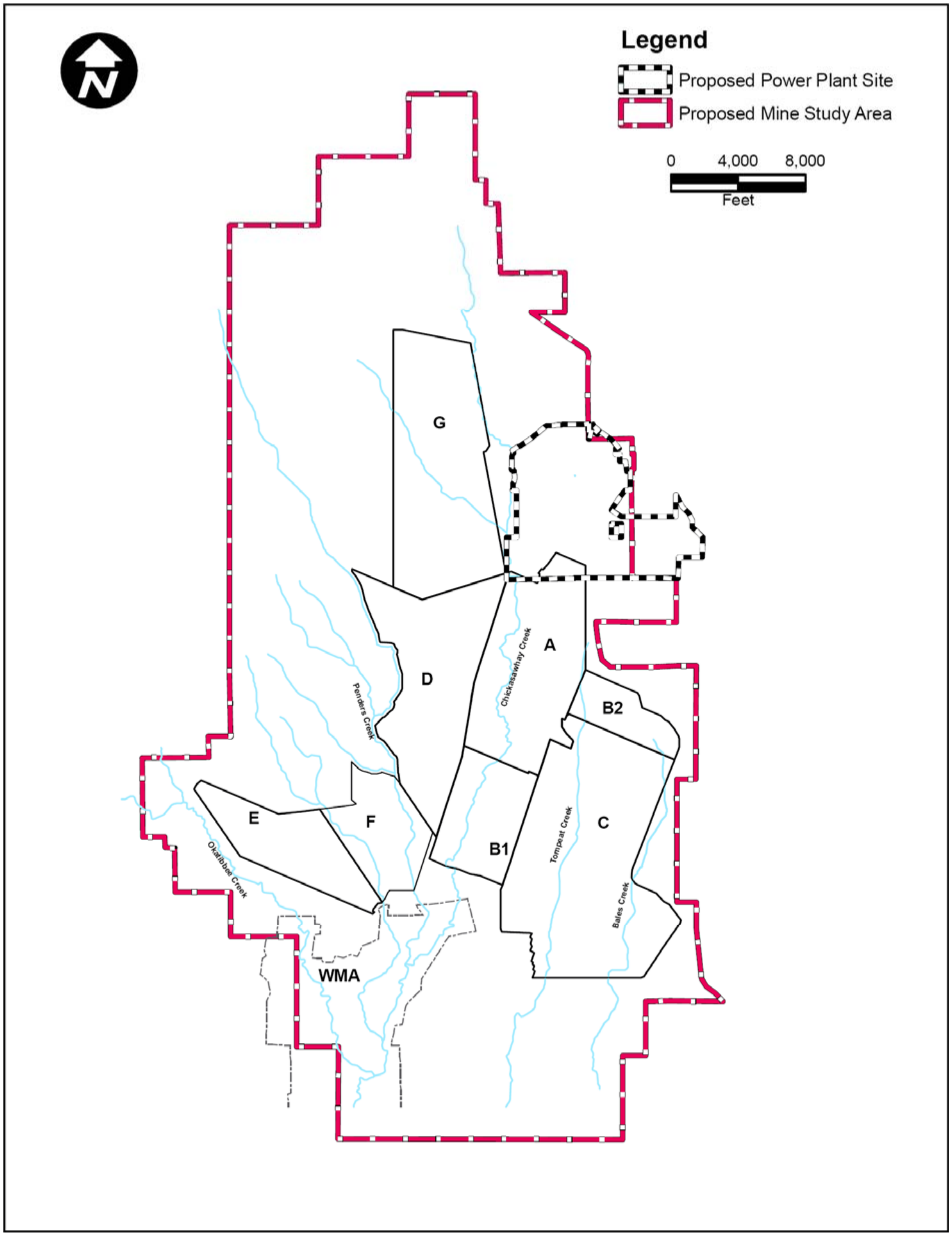

Figure 2.2-4. Conceptual Life-of-Mine Plan for Liberty Fuels Mine
Source: NACC, 2009.

would work back and forth along a north-northwest/south-southeast axis generally advancing from north to south during a 5- to 6-year period.

As the lignite reserves in the initial mine block are recovered, the subsequent mine block would be permitted and prepared for mining to provide an uninterrupted supply of lignite to the IGCC plant. The subsequent mine blocks would generally correspond in size to the initial mine block so as to provide sufficient mineable reserves to fulfill the project purpose. Whenever practicable, future mine blocks would be located adjacent to the existing mine block to provide for orderly development of the mineral resource, landscape reclamation design, and minimal long-distance relocation of mining equipment.

2.2.1.2 USACE Mine Plan Approval

As is described in Subsections 3.6.2 and 3.11.1, the mine study area contains wetlands and streams that meet the definition of Waters of the United States and, therefore, fall within the jurisdiction of USACE. As more fully described in Chapter 7, NACC would be required to obtain a federal CWA Section 404 dredge-and-fill permit from USACE prior to disturbing any Waters of the United States. Concurrent with the preparation of this EIS by DOE, **USACE** is **evaluating NACC's** application **for** the CWA 404 permit necessary to authorize construction and operation of the mine. During the evaluation of NACC's application, USACE will determine whether impacts to Waters of the United States have been minimized, with issuance of a permit only occurring following such a determination by USACE. **USACE's evaluation may result in the development of additional mine plan alternatives beyond those evaluated in this EIS.** USACE's permit, if issued, could require NACC to avoid disturbing certain Waters of the United States located within the 31,000-acre mine study area to minimize impacts to the extent practicable. **USACE will present its decision in a record of decision (ROD) that will be issued separately from DOE's ROD. USACE may also complete further NEPA review prior to issuance of its ROD.**

This EIS was prepared on the assumption that all lignite reserves in each mine block would be recovered, including the reserves lying beneath Waters of the United States. In the event of permit conditions precluding complete recovery of the lignite reserves in one or more mine block(s), NACC would have to select additional blocks to be mined beyond those shown in Figure 2.2-4 to offset the lignite reserves left in the ground by the permit or **any** ownership constraint**s**. Selection of any additional areas proposed to be mined, if any, would be based on lignite quantity (i.e., recoverable tons per acre), quality, and depth; the haul distance to the coal preparation plant; and the degree of logistical constraints.

2.2.1.3 USACE Wetland and Stream Mitigation Plan Approval

For Waters of the United States, USACE and EPA have adopted rules for minimum numerical compensatory mitigation to completely offset any wetland functional losses remaining following completion of the impact minimization analysis described previously. **These regulations, published as 33 CFR 332 by USACE and 40 CFR 230, Subpart J, by EPA, apply to NACC's pending application and are referred to as the 2008 Mitigation Rule. Should USACE decide to issue a permit to NACC, the permit would include a mitigation plan that meets the requirements of the 2008 Mitigation Rule.** The compensatory mitigation requirements include consideration of temporal losses and would be applied after USACE determined the type of mitigation that would be appropriate. The functional assessment method to be used will be the Wetland Rapid Assessment Procedure (WRAP) (Miller and Gunsalus, 1997) for determining wetland functional value losses. Final determinations for compensatory mitigation will be performed by USACE. Chapter 7 describes these regulations in more detail.

The USACE Mobile District published a draft of the standard operating procedures and guidelines in March 2009 (USACE, 2009) to address compensatory stream mitigation (included in full in Appendix B). This guidance provides standardized procedures and requirements for applying the 2008 EPA/USACE Mitigation Rule to proposed stream impacts. These procedures prescribe methods for assessing minimum compensatory requirements associated with proposed stream disturbances as well as for calculating the sufficiency of stream mitigation plans. Final determinations for implementation of these procedures would be performed by USACE.

2.2.1.4 Relationship of USACE and MDEQ Permits to DOE's Decision-Making

In addition to the USACE requirements described previously, numerous mine design, construction, operation, and reclamation constraints would be imposed on NACC by applicable laws, regulations, and permit requirements, as **are** described in Chapter 7. Because NACC must comply with these requirements, they are factored into the analysis of impacts in Chapter 4 for the surface lignite mine.

Throughout the EIS, DOE's evaluations incorporate the requirements of these federal environmental protection programs into the proposed connected surface lignite mine. DOE's analyses, therefore, focus on the impacts that would occur after incorporating the impact avoidance, minimization, and mitigation measures applied by USACE's regulatory program **as well as effluent limitations and other constraints imposed by the NPDES and SMCRA permits that may be issued by MDEQ**. This EIS also analyzes additional mitigation measures that could be incorporated to minimize impacts.

2.2.2 NATURAL GAS SUPPLY PIPELINE

As mentioned previously, the Kemper County IGCC Project CTs would be capable of operating on natural gas as well as syngas, and the duct burners in the two HRSGs would fire only natural gas. While there is a 6-inch natural gas pipeline that intersects the power plant site, this pipeline is too small and operates at too low of a pressure to supply the needs of the proposed power plant. To meet the proposed project's supply requirements, a new gas lateral would be built to connect to an existing Tennessee Gas Pipeline Company (TGPL) interstate natural gas pipeline system that is located approximately 6 miles east of the site. Figure 2.2-1 showed the location of the planned new pipeline. The new pipeline would be 20 inches in diameter and would run generally due west from an interconnection with the TGPL pipeline north of Blackwater, Mississippi. A metering station would also be constructed at the point of interconnection with the existing pipeline, as shown in Figure 2.2-1. A gas conditioning facility would be located at the terminal point of the new pipeline located on the power plant site.

The permanent right-of-way for the new pipeline would be 50 ft wide, which is typical for a natural gas line of this size. The new pipeline would be placed in the center of the 50-ft right-of-way, which would allow personnel and equipment access to the pipeline for any future maintenance and inspection purposes.

An additional 25-ft-wide right-of-way would be secured temporarily for use during pipeline construction. The full, 75-ft construction right-of-way (50 ft permanent plus 25 ft temporary) would provide space for contractor equipment during pipeline installation and space needed for dirt storage. Additional temporary workspace would also be acquired in other areas, such as at road and stream crossings, to accommodate additional construction activities at these locations (additional equipment and dirt storage). Upon completing construction, the right-of-way would be restored and revegetated (see subsequent discussion). At that time, the temporary right-of-way would revert back to the landowner.

To provide good access to the right-of-way during construction, access roads would be necessary. Several access roads have been identified and surveyed for use by the pipeline contractor and would subsequently be used for in-service pipeline maintenance and operations. Generally, more access roads available to access a pipeline right-of-way are better both from construction and maintenance standpoints to allow the contractor to move equipment easily to and from the right-of-way. Access roads could either be a private road or a public road such as a county or state road. The proposed route of the natural gas pipeline would cross ten private roads and three public roads. Based on preliminary construction engineering, less than 1 mile of new access roads would need to be built, and approximately 6 miles of existing dirt roads would need to be upgraded to support pipeline construction (and subsequent maintenance).

Mississippi Power would negotiate in good faith with landowners to acquire all rights-of-way, including fee-owned parcels, rights-of-way, and easement rights-of-way necessary to support the project. In such negotiations, Mississippi Power would use all reasonable efforts to acquire the rights-of-way in an arms-length transaction. If such transaction could not be consummated, however, Mississippi Power would exercise its right of eminent domain arising under the Constitution and laws of the State of Mississippi. In the event that eminent domain were necessary to acquire the rights-of-way necessary to support the project, the amount of compensation paid to the landowner would be the value of the acquired right-of-way as determined by a jury in accordance with Mississippi law (Mississippi Power, 2009a).

2.2.3 ELECTRICAL TRANSMISSION LINES AND SUBSTATIONS

The proposed Kemper County IGCC Project site is located north of the nearest existing Mississippi Power transmission infrastructure. New transmission facilities, including appropriate lines and substations, would be constructed to interconnect the new power plant to the existing grid and provide firm transmission service for the plant's output. Mississippi Power conducted studies to evaluate alternative routes from among possible alternatives and selected the best routes for the new lines. Subsection 2.7.2.2 summarizes the procedures for the route alternatives evaluation/selection process.

The new transmission lines would include approximately 56 miles of new 230-kilovolt (kV) transmission and approximately 9 miles of 115-kV transmission. Rights-of-way up to 125 ft wide would be required for these new transmission lines. The IGCC plant would also require approximately 24 miles of existing 115-kV transmission lines to be upgraded. The new and upgraded transmission lines are in Kemper, Lauderdale, and Clarke Counties, as shown in Figure 2.2-1. Along with the new and upgraded transmission lines, three new substations would be built; these were also shown in Figures 2.2-1 and 2.2-2.

The new electrical transmission facilities would include:

- West Feeder—An approximately 19-mile-long, 230-kV line from the power plant to new three-breaker, 230-kV ring Lauderdale West switching station connecting to existing 230-kV system.
- East Feeder—An approximately 24-mile-long, 230-kV line consisting of 18 miles of line from the power plant to new four-breaker ring Lauderdale East switching station connecting to existing 230-kV system plus 6 miles of line from Lauderdale East switching station to new Vimville Substation.

- Vimville Substation to Meridian North East—An approximately 9-mile-long, 115-kV line from Vimville substation to the existing Meridian North East substation.
- Vimville Substation to Plant Sweatt—An approximately 13-mile-long, 230-kV line from Vimville substation to Plant Sweatt (existing power plant).

As noted in Subsection 2.2.2, Mississippi Power would negotiate in good faith to acquire all rights-of-way associated with the new transmission lines and substations. Eminent domain would be used only if necessary.

The electrical transmission facilities requiring upgrades would include:

- Meridian North East Substation to Meridian Primary Substation—An approximately 7-mile-long segment of existing 115-kV line that would require reconductoring.
- Plant Sweatt to Stonewall Substation—An approximately 13-mile-long segment of existing 115-kV line that would require reconductoring.
- Plant Sweatt to Lost Gap Substation—An approximately 4-mile-long segment of existing 115-kV line that would require reconductoring.

Based on preliminary engineering of the new and upgraded transmission lines, Mississippi Power anticipates that some new structures would be of the H-frame design, and some might be single-pole. Figure 2.2-5 provides some basic design details for the former.

Some new access roads would need to be built (and some existing dirt roads would need to be upgraded) to support transmission line construction (and subsequent maintenance). The access points and roads for construction would be defined when more detailed engineering planning is completed.

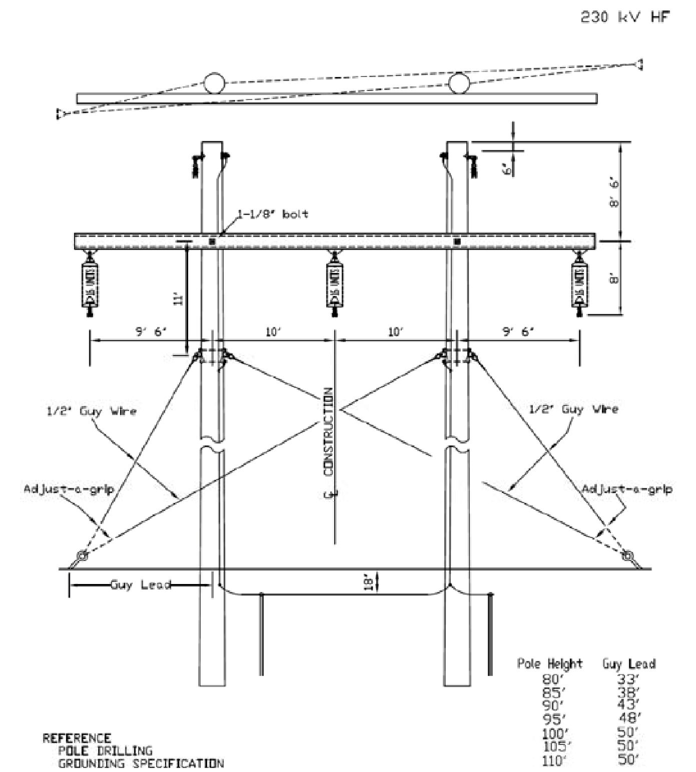

Figure 2.2-5. Design Details for H-Frame Transmission Line Structure

Source: Mississippi Power, 2009.

There are three electrical substations proposed for this project: Lauderdale East, Vimville, and Lauderdale West, as mentioned previously; Figures 2.2-1 and 2.2-2 show their locations. The proposed site of the East Lauderdale Switching Station lies along the East Feeder and is located approximately 17.5 miles southeast of the power plant site. The site of the proposed Vimville substation lies another 6 miles south, or approximately 23.5 miles southeast of the plant site. West Lauderdale switching station would be located slightly east of the terminus of the West Feeder, approximately 19.3 miles south of the power plant site.

In addition to the new and upgraded electrical transmission facilities just described, construction of the power plant and lignite mine would require new and upgraded power lines. Electrical power needed to support site construction would require improvements to the existing distribution system. The likely means would involve upgrading existing lines that run south along MS 493 from MS 16, north of the site, as shown in Figure 2.2-1. As projected by East Mississippi Electric Power Association (EMEPA) (2009a), the necessary improvements would include:

- Total of 9.5 miles of upgrade from 12 to 25 kV.
- Portion (6 miles) also converted from single- and two-phase to three-phase.
- Other system changes, including minor substation modifications and replacement of some poles.

Another possibility to provide a portion of the onsite power would involve upgrading a 1.25-mile segment of line from Klondike, south of the site, running north along MS 493 to the site.

All of this work would involve only upgrades to existing distribution lines and would be carried out by EMEPA. No new rights-of-way would be required.

Finally, operation of the mine would have greater needs for power than could be provided by existing lines or the lines upgraded for construction. Operation of the mine would require bringing a new 161-kV transmission line down from TVA's existing 161-kV line that parallels MS 16 (NACC, 2009). TVA would engineer, build, and own this new transmission line, which would be approximately 9 to 10 miles long. TVA has not yet developed specific plans or mapped a proposed route. TVA's engineering and planning activities would not take place until needed to meet the schedule for mine operation. TVA's planning process would include environmental review, likely including a public hearing (EMEPA, 2009b).

2.2.4 RECLAIMED EFFLUENT PIPELINE

The primary source of makeup water for the IGCC facility would be reclaimed effluent transported via a pipeline from two Meridian, Mississippi, POTWs: the main plant (Meridian POTW), located near downtown Meridian on MS 11 South, and the smaller East Meridian facility, located northeast of downtown Meridian on Old U.S. Highway 45 (U.S. 45) North. Figures 2.2-1 and 2.2-2 show the locations of both POTWs. A new reclaimed water pipeline would therefore need to be installed to connect the two POTWs with the surge pond at the plant site. The proposed reclaimed water supply pipeline would run from the main Meridian POTW, in a generally northeasterly direction, in an existing city right-of-way that parallels Sowashee Creek, to the East Meridian POTW. The pipeline would continue in a northeasterly direction until intersecting the East Feeder transmission corridor at a point south of U.S. 45, then continue alongside the proposed new East Feeder electrical transmission lines to the power plant site. Where coincident with the proposed new East Feeder electrical transmission lines, the new pipeline would be constructed almost entirely within the new 200-ft corridor that would also contain the transmission lines. The total length of the new pipeline from the Meridian POTW to the power plant site would be approximately 29.5 miles. The portion of the distinct pipeline corridor (i.e., from Meridian POTW to the East Feeder corridor) would be approximately 13.5 miles in length, with approximately 4 miles of that being new right-of-way.

The combined reclaimed water supply pipeline system would be capable of carrying approximately 12 MGD of water to the power plant's makeup water surge pond. Although only preliminary engineering has been completed for this pipeline, it is anticipated that the pipeline would consist of a 30-inch diameter pipe within a permanent 50-ft right-of-way. An additional 25-ft easement would be required during construction. The type of pipe material has not been selected, but the most likely options would be either steel, ductile iron, or high-density polyethylene (HDPE). Similarly, current plans would not require the addition of pumping stations along the length of the line.

As noted in Subsection 2.2.2, Mississippi Power would negotiate in good faith to acquire all rights-of-way associated with the new reclaimed effluent pipeline. Eminent domain would be used only if necessary.

2.2.5 CO_2 PIPELINES

As discussed previously, Mississippi Power intends to capture up to 67 percent of the CO_2 that would otherwise be emitted into the atmosphere. As delivered from the power plant, the CO_2 would be separated from the other emission gases and concentrated to approximately 99 percent (by volume) or more, then compressed to a supercritical (dense phase) liquid. **All of t**he liquid CO_2 would be piped **offsite for beneficial use in EOR. The CO_2 would be transported** through a new pipeline **that** would connect to an existing system near Heidelberg. As shown in Figure 2.2-1, the new CO_2 pipeline would be approximately 61 miles in total length and would have an expected 14-inch diameter (diameter could vary between 12 and 18 inches and would be **defined** during future engineering studies). **CO_2 not piped to the existing system near Heidelberg would be sent instead to an oil field in the vicinity of West King (Wayne County, west of Waynesboro). As currently depicted, this CO_2 pipeline would be collocated with the pipeline to Heidelberg for approximately 54 miles before turning to connect with the oil field as shown in Figure 2.2-1.**

The CO_2 pipeline**s** would operate at a pressure of 2,100 psi and a temperature of 95°F and would have mainline block valves approximately every 20 miles (except for crossings of water bodies, where valves might be required on either side of the water body). The H_2S content of the piped CO_2 would be less than 10 parts per million by volume (ppmv), and total sulfur content would be less than 35 ppmv. The permanent right-of-way would be 50 ft wide.

From the plant site to the terminus near Heidelberg, the CO_2 pipeline right-of-way would be co-located with (and adjacent to) the proposed right-of-way for the western leg of the proposed new transmission line (West Feeder) for the first 19 miles. **The** rights-of-way would fit within the 200-ft-wide study corridor. The pipeline would then extend beyond the West Feeder in a southwesterly direction for approximately 42 more miles, paralleling Interstate 59 (I-59) and an existing electrical transmission line right-of-way through Lauderdale, Clarke, and Jasper Counties**. The pipeline to Heidelberg would continue** to its terminus just south of Heidelberg**, while the pipeline to the oil field near West King would turn southeast to its terminus approximately 20 miles away in Wayne County (see Figure 2.2-1).**

For both end-points, a pump station would be located at the origin of the line (power plant site) to pump the liquid CO_2. A meter station would be located at the terminal point of the new line. Some new access roads would need to be built to support pipeline construction (and subsequent maintenance). The access points and roads for construction would be defined after completion of more detailed engineering and planning.

As noted in Subsection 2.2.2, it is expected that the developer/owner of the CO_2 pipeline would negotiate in good faith to acquire all rights-of-way associated with the new pipeline. Eminent domain would be used only if necessary.

2.3 CONSTRUCTION PLANS

2.3.1 POWER PLANT

Although final, detailed design of all IGCC power plant components would not be completed until 2012, construction of the proposed IGCC power plant would begin in 2010. Construction would continue until the planned commercial operation date of May 2014. Preconstruction activities would begin with clearing and grading, and the site would be graded for stormwater runoff management. Site preparation would involve construction of load-bearing concrete piers and foundations for heavy and settlement-sensitive structures. Excavation would be performed for footings and grade beams. Soil removed during site preparation would be stored in stockpiles and later spread on finished graded areas. Following site preparation, other phases of construction would include mechanical installation, piping interconnection, electrical installation, and instruments and controls configuration. Subsection 2.5.1 discusses land requirements during construction and operation.

Construction materials would consist primarily of structural steel beams and steel piping, tanks, and valves. Locally obtained materials would include crushed stone, sand, and lumber for the proposed facilities and temporary structures (e.g., enclosures, forms, and scaffolding). Components of the facilities would also include concrete, ductwork, insulation, electrical cable, lighting fixtures, and transformers. Materials would be shipped from their point of origin by various means, including, rail, truck, barge, and blue-water (ocean-going) ship. However, it is expected that all materials would ultimately be delivered to the site by truck. Truck routes to the site would rely on major highway systems, primarily including Interstate 20 (I-20) from east or west, U.S. Highway 78 (U.S. 78) from Memphis, and Interstate 10 (I-10) and I-59 from New Orleans. Although the exact routing of construction materials and major equipment is still being determined, the primary routing of general cargo from these arteries is likely to arrive from points north or south along U.S. 45 and then west along MS 16 to the junction of MS 493, where they would turn south toward the worksite. The final routing would account for road conditions, size and weight restrictions, or approvals.

Figure 2.3-1 shows the anticipated power plant construction labor force over the 3.5-year construction period. During this time, an average of approximately 500 construction workers would be on the site during construction of the gasification facilities and the combined-cycle power-generating unit. Approximately 1,150 workers would be required during the peak construction period in the first half of 2012. Most construction would occur during daylight hours, with the majority of construction workers being present on the site between 7 a.m. and 5:30 p.m.

One of the first preconstruction activities onsite would involve the relocation of a 6-inch natural gas pipeline that currently intersects the proposed IGCC power plant site. This pipeline is owned and operated by Southern Natural Gas (SNG). Mississippi Power intends to have SNG relocate this pipeline along the east side of the proposed plant site so that it would not interfere with subsequent construction of the plant. This relocation would be expected to take place in mid-2010. An approximately 8,500-ft-long portion of the existing pipeline would be replaced with a new segment of approximately 2 miles in length. The portion of the existing pipeline to be relocated would be left in place initially, then that portion interfering with power plant excavation and construction would be removed when full onsite activities commenced. The relocated route would roughly parallel and be west of MS 493. The relocated pipeline would be installed as close as possible to MS 493. The entire rerouted pipeline would be installed below ground. There would be no permanent aboveground appurtenances installed as part of the relocation.

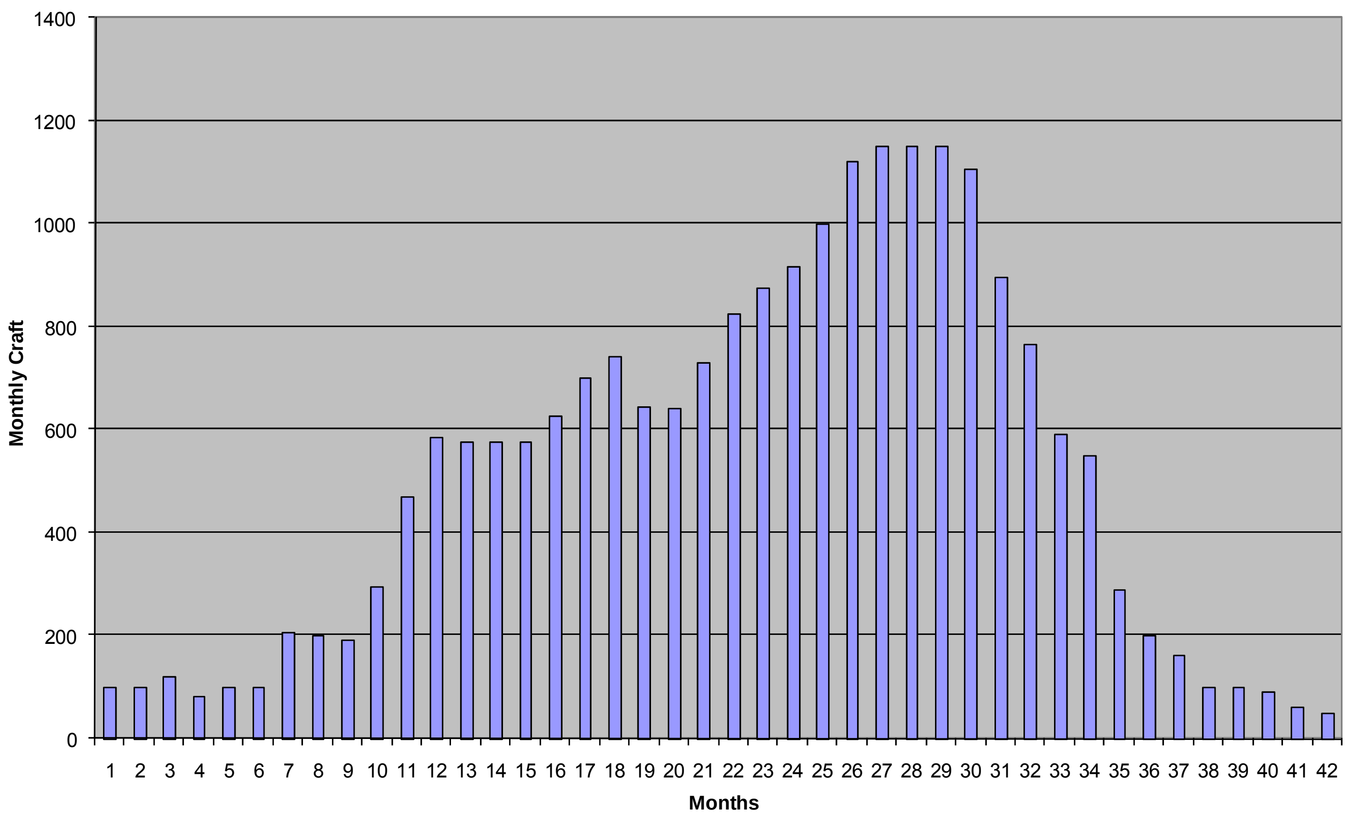

Figure 2.3-1. IGCC Power Plant Monthly Craft Labor Projection
Source: SCS, 2008.

The permanent right-of-way for the relocated pipeline is planned to be 40 ft, and the centerline of the pipeline would be located to allow personnel and equipment access for any future maintenance and inspection purposes. During construction, an additional 15 ft of temporary workspace would be obtained next to the permanent right-of-way. Upon completing construction, the right-of-way would be restored and revegetated (see further discussion of pipeline construction methods in Subsection 2.3.3).

2.3.2 SURFACE LIGNITE MINE

Construction activities associated with the proposed lignite surface mine (Liberty Fuels Mine) would commence in 2011 and continue through the first quarter of 2014, overlapping those of the IGCC power plant. Mine-related construction would consist of:

- Assembling the mining dragline to be used to excavate overburden and interburden.
- Construction of lignite handling and mine infrastructure facilities.
- Preparation of the initial mining area (hereinafter referred to as premining activities).

Figure 2.1-**6** showed the locations proposed for these facilities. Details of the stages of mine construction are provided in the following subsections.

2.3.2.1 Dragline Assembly

The dragline for the proposed mine is presently in storage offsite. It would be necessary to assemble the dragline before mining could begin, and an assembly site of approximately 45 acres would need to be cleared, graded, and graveled to provide the area necessary to store and assemble the machine, which would be shipped to the site in parts by the truckload. **Prior to conducting land clearing, NACC would survey the site and remove and properly dispose of offsite any regulated substances (e.g., drums of oil, hazardous materials, or asbestos-containing materials).** Construction trailers and electric power also would be supplied to the assembly site, along with parts storage trailers. The dragline assembly site would be adjacent to the mine facilities described in the following subsections and within the plant site area.

2.3.2.2 Lignite Handling Facilities

The lignite handling facilities would consist of: (1) haul roads and bridges/culverts capable of supporting large off-road haul trucks, (2) an open lignite stockpile area, (3) one or more truck dumps (i.e., receiving hoppers), (4) the primary crusher, (5) a secondary crusher, (6) conveyor belts, (7) crushed lignite storage barn, and (8) stormwater management (e.g., sediment control) ponds. Based on current plans, the lignite handling facilities would be located immediately southwest of the IGCC facilities within the plant site area, as shown on Figure 2.1-**6**. **Similar to the dragline assembly site, the area where the lignite handling facilities would be located would be surveyed for regulated materials; materials found would be managed in accordance with applicable regulations.**

The lignite handling facilities would have to be located and designed to meet a series of siting and performance standards adopted by the MDEQ SMCRA Regulations, as well as other federal, state, and local laws and regulations. Chapter 7 of the EIS more completely explains the applicability, scope, and procedural aspects of the regulatory oversight of the Kemper County IGCC Project. In addition to the MDEQ SMCRA Regulations, the lignite handling facility would be subject to MDEQ permits and operating performance standards that would regulate air emissions and water discharges. The proposed construction of haul roads in waters of the United States would have to be authorized as one component of the federal CWA Section 404 dredge-and-fill permit for the entire mine, which would be evaluated by USACE under its regulations as described in Subsections 2.2.1.2 and 2.2.1.3.

A sediment control (i.e., stormwater management) pond would be constructed at the location shown on Figure 2.1-**6** by damming **an** intermittent stream tributary to Chickasawhay Creek. The stormwater management pond would be sized to at least contain or treat the runoff from the 10-year, 24-hour precipitation event on the contributing drainage area in accordance with MDEQ SMCRA Regulations. To meet this criterion, the pond, labeled SP-3, would occupy 50 acres. The impoundment structure (i.e., the dam) would be designed to meet the requirements of the MDEQ SMCRA and federal mine safety and health regulations with respect to dam stability and safety. In addition, MDEQ**'s NPDES** regulations would apply technology **(40 CFR 434)** and water quality-based numerical effluent limitations and aquatic life criteria to all water discharged from the pond. Because the impoundment dam would be located in waters of the United States, the USACE Section 404 permit would have to authorize construction and operation of **the** impoundment. **Similar to the dragline assembly site, the SP-3 area would be surveyed for the presence of regulated materials prior to commencing construction. Regulated materials found would be managed in accordance with applicable federal regulations.**

2.3.2.3 Mine Facilities

The mine facilities would include an office building, warehouse, and maintenance shop. The maintenance shop would consist of service bays for the off-road haul trucks, bulldozers, front-end loaders, trackhoes, and other mobile equipment used in mining and reclamation. As shown in Figure 2.1-**6**, the mine facilities would be located in the southern portion of the plant site, along the west side of MS 493, with an internal mine road constructed to connect these facilities to the main mine haul road. **Similar to the dragline assembly site, this area would be surveyed for the presence of regulated materials prior to land disturbance. Regulated materials found would be managed in accordance with applicable regulations.**

2.3.2.4 Premining Activities

During the construction of the facilities described previously, a series of steps would be undertaken by NACC to prepare initial mining block A for excavation and extraction. These actions would generally fall into two categories: surface water management/protection and mine dewatering. **Similar to the dragline assembly site, this area would be surveyed for the presence of regulated materials prior to land disturbance. Regulated materials found would be managed in accordance with applicable regulations.**

Surface Water Management and Protection

NACC is proposing to design, construct, and operate several surface water management structures within initial mining block A to maintain the hydrologic balance and surface water quality. These would include stream diversion channels, stormwater runoff collection channels, and sedimentation ponds.

As will be described in Subsection 2.4.2, the initial mine block includes approximately 15,000 linear ft of Chickasawhay Creek (Mississippi Automated Resource Information System [MARIS], 2009b). Accordingly, NACC would include, in its USACE and MDEQ permit applications, plans to divert the flow in Chickasawhay Creek from the existing channel to a temporary diversion channel, as shown in Figure 2.3-2. The temporary diversion channel would be located to the west of the existing channel, generally below the 400-ft elevation contour in Sections 9, 16, 17, 20, and 29, Township 8 south, Range 15 east. The diversion channel would flow in a south-southwest direction, which will allow the diversion channel to receive flow from the intermittent tributary channels currently flowing into **this segment of** Chickasawhay Creek from the west.

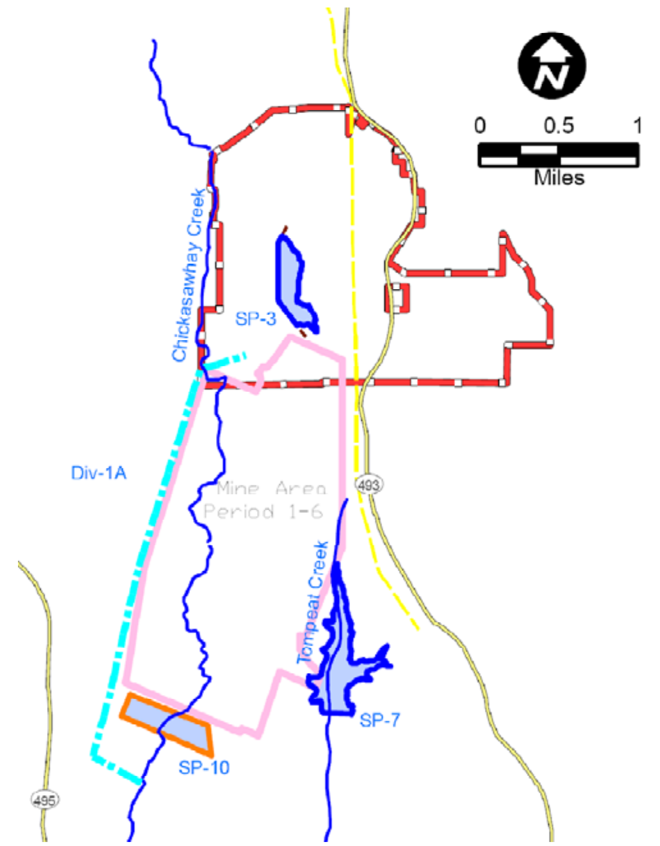

Figure 2.3-2. Initial Mining Area Water Management

Sources: NACC, 2009; ECT, 2009.

The Chickasawhay Creek diversion channel would be sized to safely pass the peak runoff generated by the 100-year, 6-hour precipitation event in accordance with MDEQ SMCRA Regulations. **T**he diversion channel would **be constructed using design metrics measured in a reference reach that exhibits stable conditions and healthy attributes (e.g., channel sinuosity, bank fall flow capacity, in-stream habitat, etc.). If an appropriate reference reach is not available, the channels will be constructed so that the stream establishes a stable pattern, profile, and dimension. Diversion channel designs would be submitted to MDEQ and USACE for approval prior to construction and, and designs would comply with the MDEQ SMCRA design and performance criteria.** Figure 2.3-3 illustrates a diversion channel at NACC's Red Hills Mine.

Figure 2.3-3. Photograph of Diversion Channel at NACC's Red Hills Mine
Source: NACC, 2009.

In addition to the diversion of Chickasawhay Creek, five intermittent streams are present in the proposed initial mine study area, including a segment of Tompeat Creek upstream of its designation as perennial (MARIS, 2009b). These streams, which total approximately 8,800 ft in length, would be managed through interception, routing to a sedimentation pond **using collection channels within active mine areas**, and discharge into Tompeat or Chickasawhay Creeks.

Drainage from active portions of initial mining block A would be captured and routed to sedimentation ponds constructed by damming Tompeat Creek (i.e., SP-7) or excavating a below-grade structure in the Chickasawhay Creek floodplain (i.e., SP-10) (Figure 2.3-2). The approximate size of these areas, labeled SP-7 and SP-10, would be 90 and 58 acres, respectively. The SP-7 pond would be capable of containing the runoff generated by the 10-year, 24-hour precipitation event in accordance with MDEQ SMCRA Regulations. The SP-7 impoundment dam would be designed to meet the dam safety and stability rules established by the MDEQ SMCRA and federal mine safety and health regulations. In addition, USACE would have jurisdiction over both ponds due to their locations in waters of the United States.

Mine Dewatering

Often, surface mines need to dewater the areas to be excavated to maintain the side slopes and mine working surfaces between land surface and the base of the mine excavation to ensure safe working conditions. At the Liberty Fuels Mine site location, most of the overburden segments have low permeability, making advanced dewatering unnecessary. However, one overburden sand layer, referred to as J5, and the underburden layer, referred to as G5, would require management.

To address these hydrogeologic attributes, an advanced dewatering well network would be operated for approximately 1 year prior to initiating mining excavations. Well spacing would be on the order of 300-ft centers. Operation of the two well systems, one addressing the J sand and one addressing the G sand, would generate approximately 765 gpm, or 1.1 MGD, for approximately 1 year. The water generated would be discharged to Chickasawhay Creek **through a permitted NPDES outfall**.

2.3.2.5 Construction Schedule

Construction activities for the lignite handling facilities would commence in early 2012 and continue through the fourth quarter of 2013. The two sediment control ponds associated with the lignite handling facilities would be built in 2012. The dragline assembly site would be constructed in mid 2010. The dragline would be stored onsite until the first quarter of 2013 when assembly would commence. After an 18-month assembly period, the dragline would be ready to begin overburden removal operations in the second quarter of 2014. The two sediment control ponds and the stream diversions associated with the initial mining area would be built over an 18-month period beginning in early 2013 and extending through mid 2014. Construction of the mine facilities would begin in 2013 and extend through early 2014. The total mine construction workforce from 2012 through 2014 would vary from 45 to 155 people, depending on the overlap between the various construction projects.

2.3.3 LINEAR FACILITIES

Construction of the related linear facilities connected to the Kemper County IGCC Project would follow a similar schedule to the plant and mine facilities, beginning in 2011 and continuing through 2013. The construction of all linear facilities would generally begin with surveying and marking the centerline and outer limits of the proposed rights-of-way and necessary access roads.

For most linear projects, the right-of-way itself is used as access for construction, long-term maintenance, and emergency repairs. However, for this project, use of the right-of-way would not always be possible or practicable, and it is expected that additional access roads would be required to reach rural, isolated areas of some of the project corridors. Routes for all of these roads have not been identified at this time but would be coordinated with the affected landowners and sited to minimize environmental impacts. All proposed access roads would be surveyed for the presence of threatened and endangered species, wetlands, and cultural resources prior to any land clearing or disturbance, just as the main linear facility study corridors were. Construction of these roads would typically require the placement of clay to provide an adequate foundation and a cover of limestone gravel to prevent erosion.

Structural stormwater pollution controls as well as operational Best Management Practices (BMPs) would be installed prior to the beginning of any construction activities, including land clearing or site preparation. The purpose of these controls would be to prevent erosion of disturbed areas and the movement of sediment offsite. Examples of structural controls would include the placement of silt fencing at all locations where stormwater from any disturbed soils or denuded areas could leave the site and enter a small watershed as well as the use of stabilization practices on areas where construction has been completed. BMPs would include the proper management of onsite debris during construction, minimization of the exposure of significant construction materials to stormwater, and limiting the use of fertilizers for revegetation of disturbed areas.

Construction methods would be similar for each of the three planned underground pipelines. The first stage of construction would entail clearing the full width of the right-of-way (temporary plus final) of trees and brush. After clearing, the right-of-way would be leveled, or graded, so that equipment could operate safely. Next, the trench for the pipeline would be dug. Dirt removed during trenching would be placed on one side of the trench, while the opposite side would be used for pipeline welding operations and operation of other equipment. Weld areas would be radio-graphically inspected, coatings applied to welded areas, and the pipe lowered into the trench. In the event that HDPE pipe is selected as the preferred material for the reclaimed water pipelines, individual pipe segments would be joined using adhesives as opposed to welding. The previously removed soil would be used to fill the trench, and the pipeline would be filled with water and pressure-tested using pressures higher than the normal operating pressures. Typically, each pipeline would be covered by a minimum of 3 ft of soil. The pipeline would be buried deeper when needed to accommodate planned surface activities, or where it crossed under roadways or beneath bodies of water. After pipeline installation and testing, the line would be dewatered and the site thoroughly cleaned up. Finally, the right-of-way would be restored as close as possible to its original condition, including revegetation. Figure 2.3-4 illustrates some of the major activities associated with pipeline construction.

Construction of the new electrical transmission lines would vary from that of the pipelines in that there would be no grubbing of the cleared right-of-way. Trees and shrubs would be shear cut and mowed as necessary to ground level, with no removal of the stumps except where they would directly affect the placement of tower supports. Tower locations would be designed to avoid impacts to wetlands and other environmentally sensitive areas. With the right-of-way prepared, concrete foundations for the steel poles would be poured and allowed to cure, the poles would be erected, and the new conductors would be pulled into position, final connections made, and the line placed in service. For reliability and safety reasons, construction of the new and upgraded lines might require temporary circuit outages, depending on load studies and weather.

The portions of the transmission system requiring upgrades would make use of existing transmission rights-of-way. These rights-of-way have been well maintained, including road access, regular mowing, and danger tree trimming. In some areas, some additional tree clearing would be necessary for placement of the new structures and stringing of the new conductors. The current rights-of-way have adequate access roads, and new access roads would not have to be built. In a few instances, construction pads might have to be cut into the terrain to properly and safely operate large equipment, such as cranes and concrete trucks. These construction pads would be placed within the limits of the existing rights-of-way.

Clearing and Grading

Trenching

Laying Pipe and Backfilling

Revegetated Right-of-Way

Figure 2.3-4. Stages of Pipeline Construction
Source: SCS, 2009.

Each of the three new substation sites is larger in acreage than would be required for the new facilities. Each site has been mapped for wetlands and other ecologically sensitive features. As part of future design engineering, each site would be surveyed to determine the location and boundaries of the actual substation area and layout. Wetlands and sensitive areas of the site would be avoided to the extent possible. The substation construction areas would then be cleared, grubbed, and graded. Necessary foundations and drainage features would then be constructed on the site followed by the installation of electrical equipment, perimeter fencing and other security features, and infrastructure.

2.4 OPERATIONAL PLANS

2.4.1 POWER PLANT

After mechanical checkout of the proposed facilities, demonstration (including data analysis and process evaluation) would be conducted over a 4.5-year period from mid-2014 through 2018. During the demonstration, the test program would focus on achieving reliable plant operation (at least 80 percent gasifier availability) with high thermal efficiency, low emissions, equipment performance improvement, and low operation and maintenance costs. Workers would include a mix of plant operators, craft workers, managers, supervisors, engineers, and clerical workers. The IGCC facility would require skilled operations and maintenance personnel, with temporary construction or maintenance workers onsite for periodic outages and additional work. An average of approximately 20 vehicles would be used for operational activities on the site. Upon successful completion of the demonstration, commercial operation would follow immediately. The facilities would be designed for a lifetime of 40 years, including the 4.5-year demonstration period.

Staff size would vary between the demonstration period and the period of commercial operation. Operations staff would be assembled during the last 18 months of construction for training and to assist with startup of the facilities. The IGCC plant workforce would consist of approximately 105 employees. Of those 105 employees, 15 workers would provide support only during the startup and demonstration phases of the project, while 90 employees would be needed over the lifetime of the facilities (i.e., during startup, demonstration, and commercial operation).

The size of the day shift crew would range from 82 during startup and demonstration to 67 during commercial operation. The size of the night shift crew would be approximately 23 employees for the lifetime of the facilities. The staff would work two 12-hour shifts a day, with shift changes expected around 5:30 a.m. and 5:30 p.m.

During initial startup and ramp-up of the proposed IGCC project, the facility would receive lignite from the existing Red Hills Mine, located in Choctaw County, Mississippi. The Red Hills Mine is located on the same lignite formation as the design fuel and would supply lignite to the proposed plant for approximately 6 months. During this period of ramp-up, lignite would be delivered by commercial truck along public highways. The probable route from Red Hills to the Kemper County IGCC facility entrance would be via MS 15 south, MS 490 east, MS 397 south, and MS 493 south (total distance of approximately 70 miles; Subsection 3.14.2 provides details). The Red Hills Mine is located approximately 60 miles to the north-northwest of the proposed plant. An average of 50 to 60 trucks per day would be expected to make the round trip. Once the ramp-up period is completed, truck deliveries of lignite from the Red Hills Mine would cease.

2.4.2 SURFACE LIGNITE MINE

Operation of the Liberty Fuels surface lignite mine would commence in late 2013 with overburden removal in the mining block being prepared for mining, as described previously in Subsection 2.3.2.4. Overburden removal to uncover the initial lignite to be extracted would occur during IGCC plant start-up, with lignite extraction commencing concurrent with the completion of the IGCC startup phase.

Prior to conducting land clearing, surveys for the presence of regulated materials would be conducted. Any regulated materials found would be managed in accordance with applicable regulations.

Land clearing would occur in advance of mining using conventional construction equipment, with the unmarketable vegetation either burned or buried. Mining would consist of removing the overburden to expose the lignite. The primary overburden removal machine would be an electrically powered walking dragline with an 80-cubic-yard bucket. The dragline would be capable of moving overburden up to 100 ft thick and depositing it in previously mined areas. Overburden in excess of 100 ft would be removed by a front-end loader or trackhoe; it would be loaded into off-road trucks, hauled around the pit, and deposited into previously mined areas. In some situations, overburden in excess of 100 ft depth would be removed by bulldozers pushing the excess overburden material into the previously mined area. Interburden between the lignite seams would be removed by mobile equipment or by bulldozers in much the same manner. Figure 2.4-1 outlines in cross-section view a typical mining sequence at the proposed lignite mine.

Following overburden removal, the lignite would be loaded into trucks by a trackhoe, front-end loader, or continuous surface miner. The trucks would then transport the lignite to the lignite handling facilities via mine haul roads. These roads would be constructed of compacted fill with a surface material designed to support the weight of the fully loaded haul trucks. The mine would use water trucks to spray water on the roads to control fugitive dust.

Approximately 12,275 acres would be disturbed over the life of the mine. During the proposed 40-year life of mine (2013 to 2053), an average of 275 acres per year would be disturbed by lignite extraction. However, because physical reclamation would be completed within 3 years of lignite excavation, the number of acres in a disturbed state at any given time would range from 1,271 to 1,897 acres from 2014 through 2054. Table 2.4-1 presents NACC's estimates of disturbed and reclaimed acres per year for the life of the mine. **As shown on Table 2.4-1, areas disturbed by mining operations would be reclaimed as uplands or as mitigation wetlands and streams.**

Once delivered to the lignite handling facilities, the lignite would pass through the primary and secondary crushers, with the sized product conveyed to the storage barn. From the storage barn, the lignite would be conveyed from the mine to silos at the power plant that would supply the IGCC gasifiers.

2.4.2.1 Premining Activities—Future Mining Areas

As mining progresses across the portions of the initial mine block approved for disturbance by the USACE and MDEQ permits, it would be necessary for NACC to periodically modify the surface water management system and the mine dewatering systems. As mining approaches completion in the initial mine block, NACC would construct similar systems in the next mine block.

The surface water management and protection systems would be designed for site-specific conditions to meet minimum MDEQ performance standards related to maintaining the hydrologic balance and **in-stream** water quality. Generally, the methods and techniques would be similar and in addition to those described previously in Subsection 2.3.2 and would include stormwater runoff control channels, stream diversion channels, flood protection levees, and sedimentation ponds and outfalls. Table 2.4-2 and Figures 2.4-2a through 2.4-2g illustrate the changes to the surface water management system as mining is proposed to advance from initial mining block A through final mining block G. If and as approved by MDEQ and USACE permits, NACC is proposing to construct and maintain up to 60,500 linear ft of temporary diversion channels to reroute existing stream flows in Chickasawhay Creek, Penders Creek, and unnamed tributaries to Chickasawhay and Bales Creeks. The diversion channels would be temporary and maintained until reclaimed stream channels would be capable of receiving upstream flows and drainage from the adjacent reclaimed watersheds. NACC is proposing to design and construct the diversion channels to safely pass flows generated by the 100-year, 6-hour storm event, which would meet or exceed MDEQ SMCRA Regulations. To meet water quality permit conditions, up to 56,000 linear ft of temporary stormwater runoff control channels would be constructed along the perimeter and within active mining areas. The

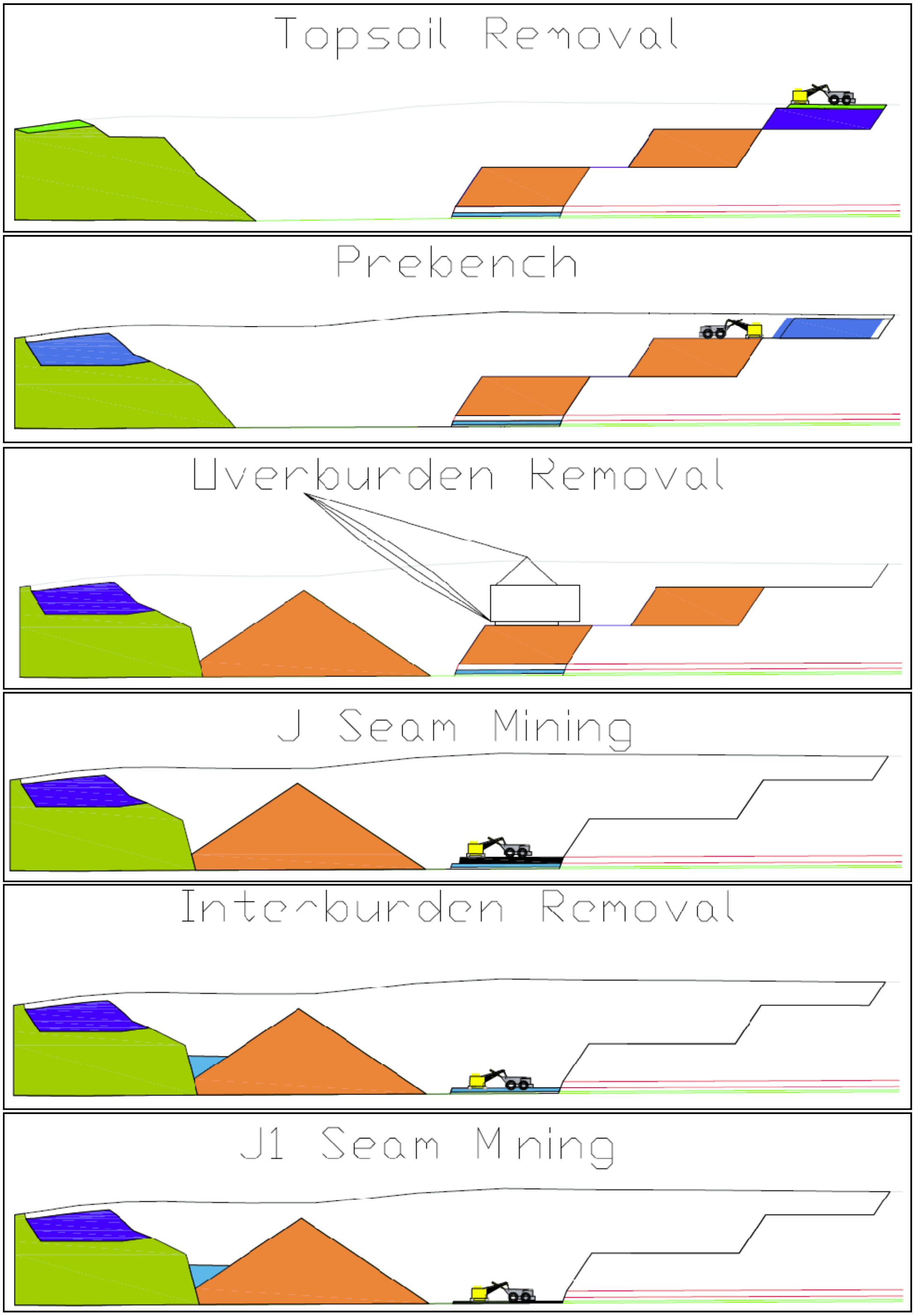

Figure 2.4-1. Typical Mining Sequence
Source: NACC, 2009.

Table 2.4-1. Liberty Fuels Mine—40-Year Mine Plan, Estimated Acres Disturbed

		Acres							
Period	Year	Mined	Ponds and Diversions	Facilities	Ponds Mined	Miscellaneous*	Total Disturbed	Reclaimed	Cumulative Disturbed
1	2012		123.00	320		12.30	455.30		455.30
2	2013	135.93	73.00			20.89	229.82		685.12
3	2014	271.86				27.19	299.05		984.17
4	2015	271.86				27.19	299.05	12.30	1,270.92
5	2016	271.86				27.19	299.05	156.82	1,413.14
6	2017	271.86				27.19	299.05	299.05	1,413.14
7	2018	271.86	51.00			32.29	355.15	299.05	1,469.24
8	2019	277.88			-26	27.79	279.67	299.05	1,449.86
9	2020	277.88				27.79	305.67	299.05	1,456.48
10	2021	277.88	127.00			40.49	445.37	304.15	1,597.70
11	2022	277.88				27.79	305.67	305.67	1,597.70
12	2023	263.76	91.00		-45	35.48	345.24	305.67	1,637.27
13	2024	263.76			-45	26.38	245.14	318.37	1,564.04
14	2025	263.76				26.38	290.14	305.67	1,548.51
15	2026	263.76				26.38	290.14	299.24	1,539.41
16	2027	263.76				26.38	290.14	290.14	1,539.41
17	2028	263.76				26.38	290.14	290.14	1,539.41
18	2029	263.76				26.38	290.14	290.14	1,539.41
19	2030	263.76				26.38	290.14	290.14	1,539.41
20	2031	263.76				26.38	290.14	290.14	1,539.41
21	2032	263.76	44.00			30.78	338.54	290.14	1,587.81
22	2033	312.60			-7	31.26	336.86	290.14	1,634.53
23	2034	312.60			-7	31.26	336.86	290.14	1,681.26
24	2035	312.60			-7	31.26	336.86	294.54	1,723.58
25	2036	312.60			-6	31.26	337.86	343.86	1,717.58
26	2037	312.60	66.00		-6	37.86	410.46	343.86	1,784.18
27	2038	262.20				26.22	288.42	343.86	1,728.74
28	2039	262.20				26.22	288.42	343.86	1,673.30
29	2040	262.20	20.00			28.22	310.42	350.46	1,633.26
30	2041	339.46			-6	33.95	367.41	288.42	1,712.25
31	2042	339.46	96.00		-6	43.55	473.01	288.42	1,896.83
32	2043	177.41				17.74	195.15	290.42	1,801.56
33	2044	177.41				17.74	195.15	373.41	1,623.31
34	2045	177.41				17.74	195.15	383.01	1,435.45
35	2046	177.41				17.74	195.15	195.15	1,435.45
36	2047	177.41				17.74	195.15	195.15	1,435.45
37	2048	177.41	96.00			27.34	300.75	195.15	1,541.05
38	2049	177.41				17.74	195.15	195.15	1,541.05
39	2050	177.41				17.74	195.15	195.15	1,541.05
40	2051	177.41				17.74	195.15	204.75	1,531.45
41	2052	177.41				17.74	195.15	195.15	1,531.45
42	2053	177.41				17.74	195.15	195.15	1,531.45
43	2054	0.00				0.00	0.00	195.15	1,336.30
44	2055	0.00				0.00	0.00	1,336.30	0.00
Total		**10,224.38**	**787.00**	**320**	**-161**	**1,101.14**	**12,271.52**	**12,271.52**	

*Acres for pit ends, roads, etc. (10 percent of total acres).

Source: NACC, 2009.

Table 2.4-2. Summary of Mine Support Structures

	Diversion Channels				Levees				Sedimentation Ponds			
Earliest Year Built	Mine Block	Number/ Length (ft)	Latest Year Reclaimed	Maximum Years in Service	Number/ Length (ft)	Creek	Latest Year Reclaimed	Maximum Years in Service	Number/ Total Size (acres)	Wetland Acres	Watershed Controlled (acres)	Maximum Years in Service
2012	A	DIV1A/15,000	2033	21					SP3/50 SP7/90 SP10/58*	43 26 13	364 738 N/A	43 10 7
2019	B1 and B2	DIV1B/4,800	2033	14					SP1/36*	26	N/A	23
2023	C	DIV9/5,200	2040	17	LEV5/2,800	Unnamed tributary of Bales Creek	2040	17	SP8/90 SP9/104	8 23	2215 1575	17
2033	D	DIV15/5,000 CC4/20,700 CC5/19,000	2043	10	LEV6/19,600 LEV7/3,900	Chickasawhay	2043	10				
2038	E	CC6/7,400 CC9/3,600 CC7/8,900	2055	17	LEV1/11,200	Okatibbee	2055	17	SP11/53*	38	N/A	15
2040	F	DIV14/8500 CC10/11,400 CC11/7,000 DIV16/8,100	2055	15					SP14/27*	6	N/A	13
2043	G	DIV7/10,800 DIV8/3,100	2055	12	LEV2/11,300 LEV 3/5,200	Chickasawhay	2055	12	SP12/18* SP13/26*	12 26	N/A	12

Note: DIV = reroute diversion channel.
CC = stormwater collection channel within active mining area.
LEV = levee.
SP = sedimentation (water treatment) pond.

*Excavated, belowgrade structure.

Source: NACC, 2009.

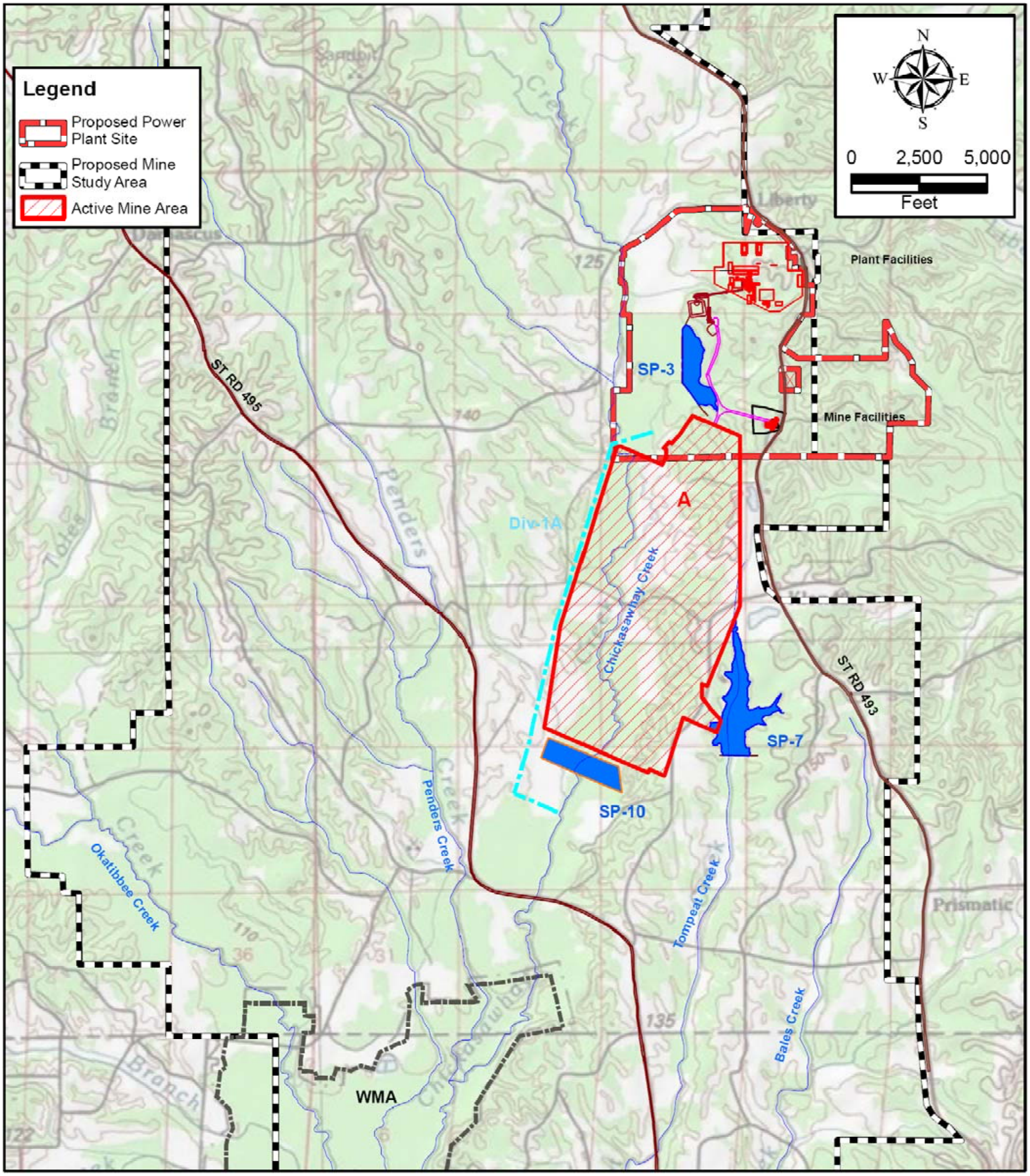

Figure 2.4-2a. Liberty Fuels Mine: Block A
Sources: NACC, 2009. ECT, 2009.

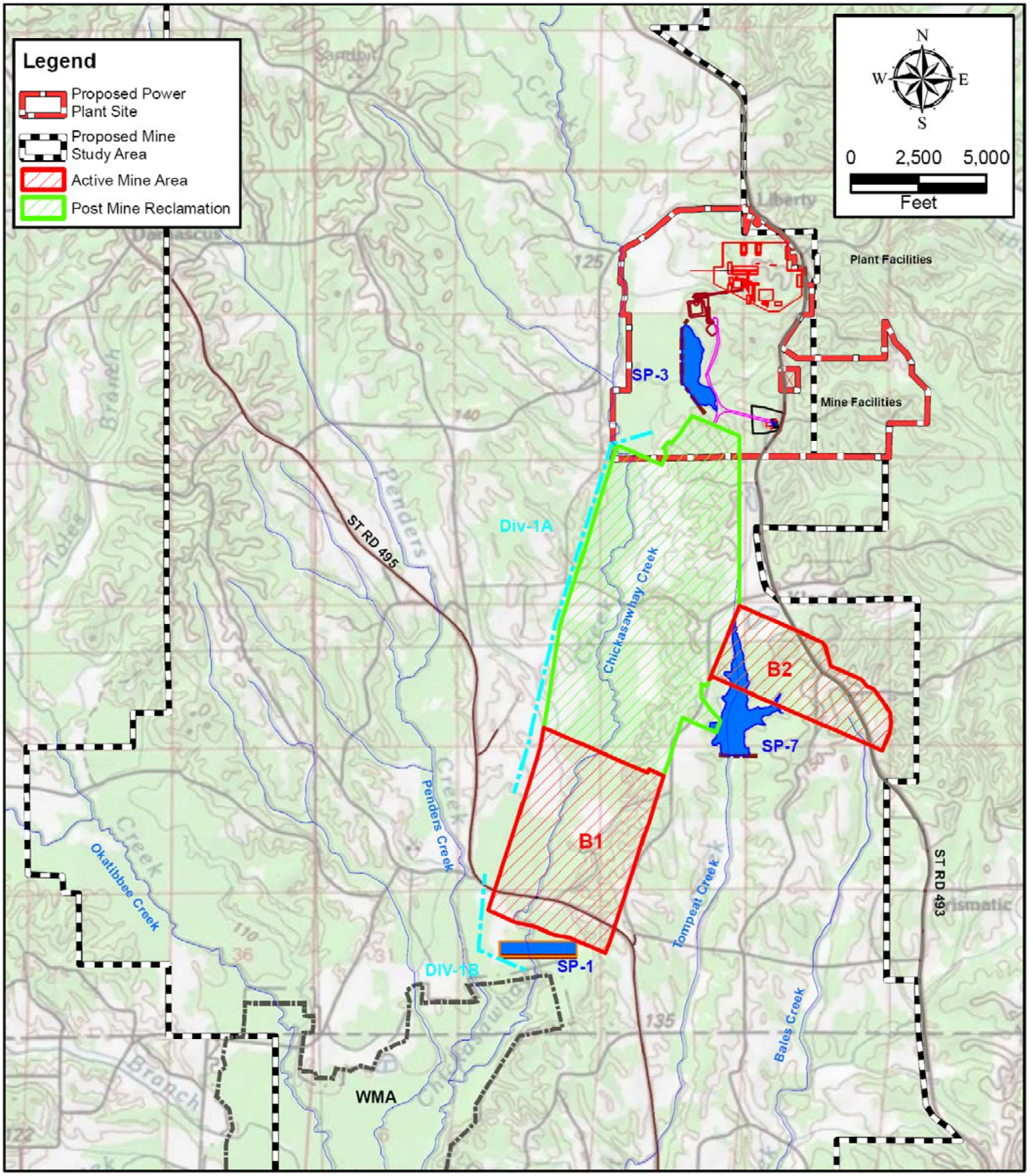

Figure 2.4-2b. Liberty Fuels Mine: Blocks B1 and B2
Sources: NACC, 2009. ECT, 2009.

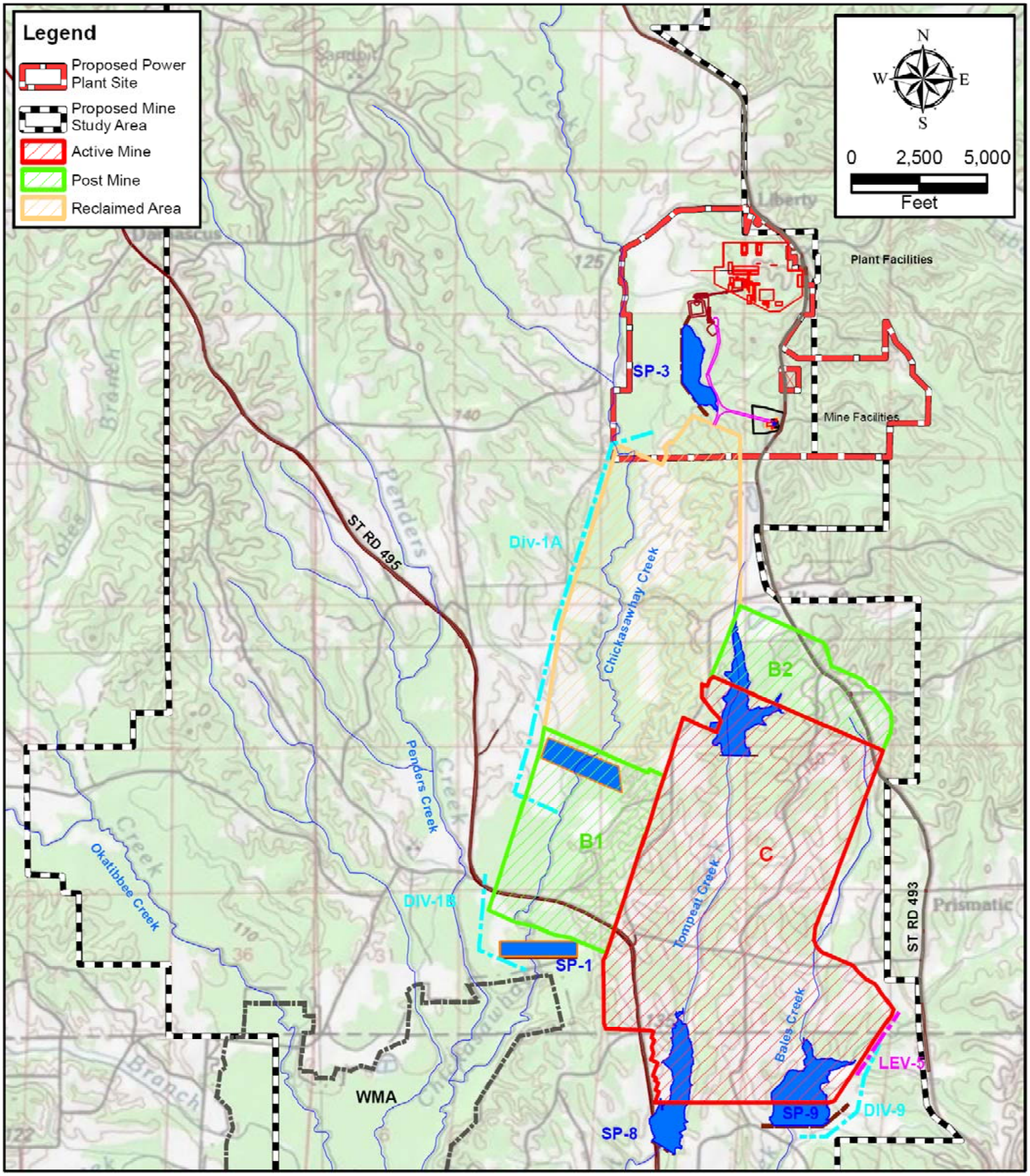

Figure 2.4-2c. Liberty Fuels Mine: Block C

Sources: NACC, 2009. ECT, 2009.

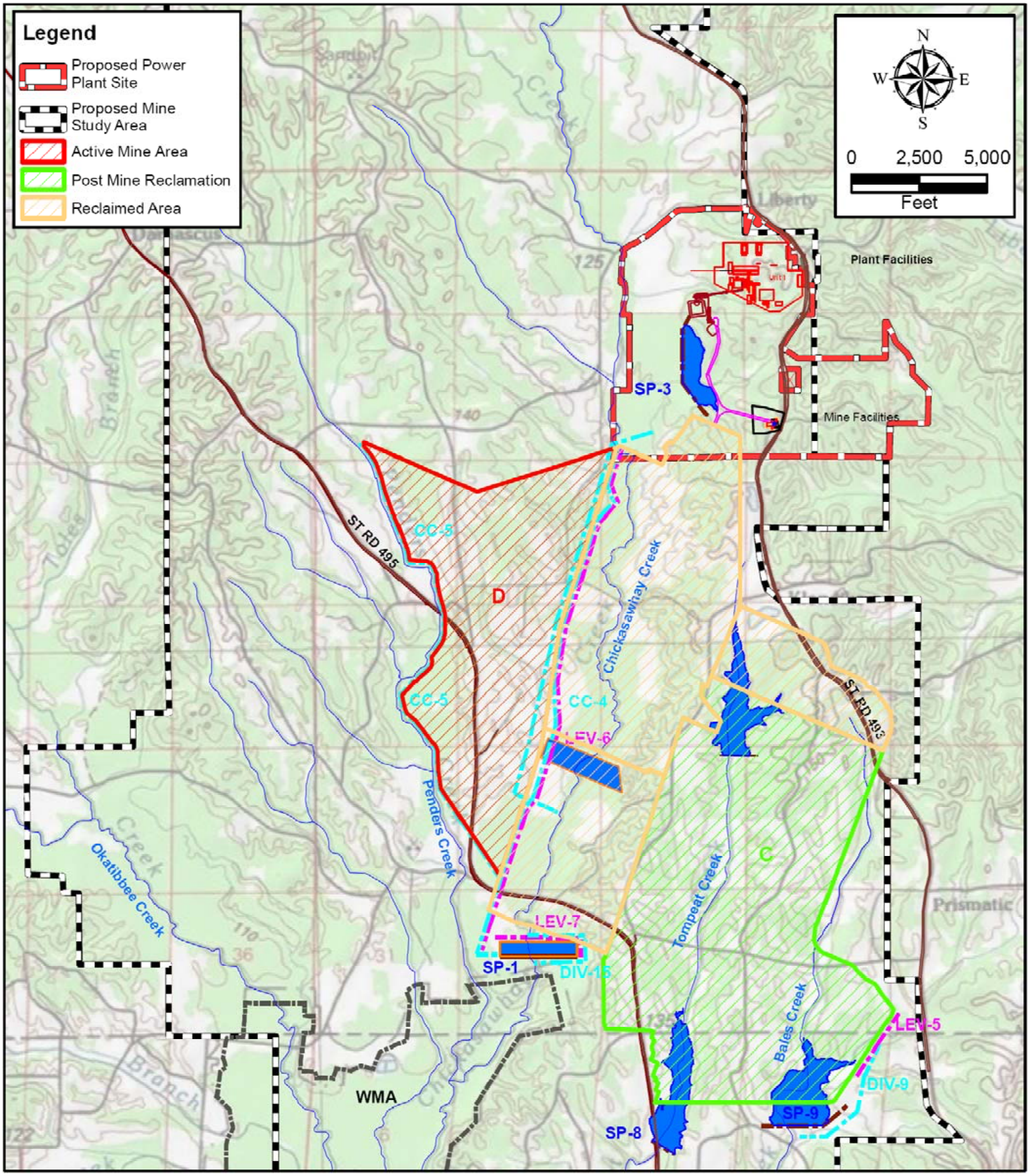

Figure 2.4-2d. Liberty Fuels Mine: Block D

Sources: NACC, 2009. ECT, 2009.

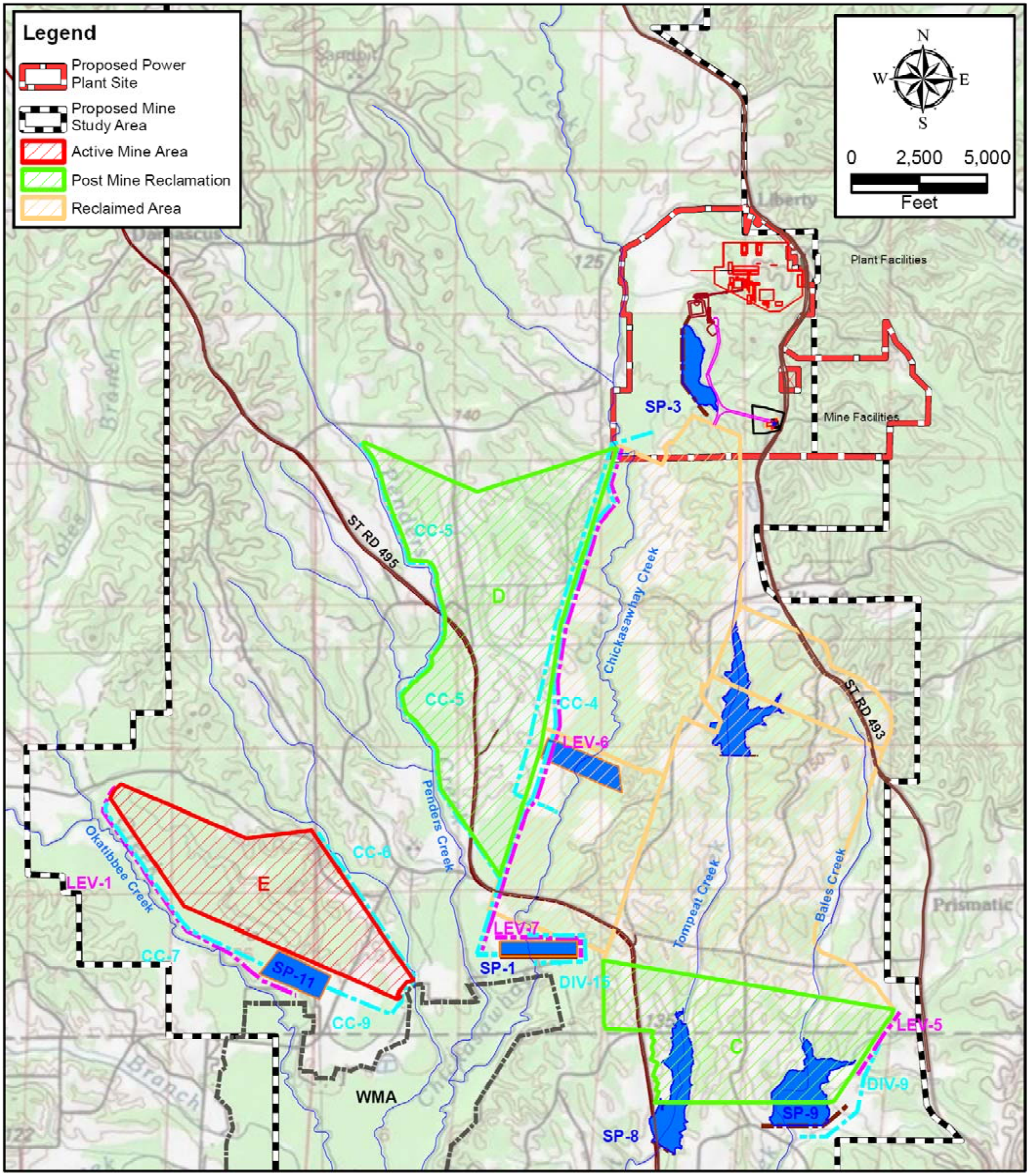

Figure 2.4-2e. Liberty Fuels Mine: Block E
Sources: NACC, 2009. ECT, 2009.

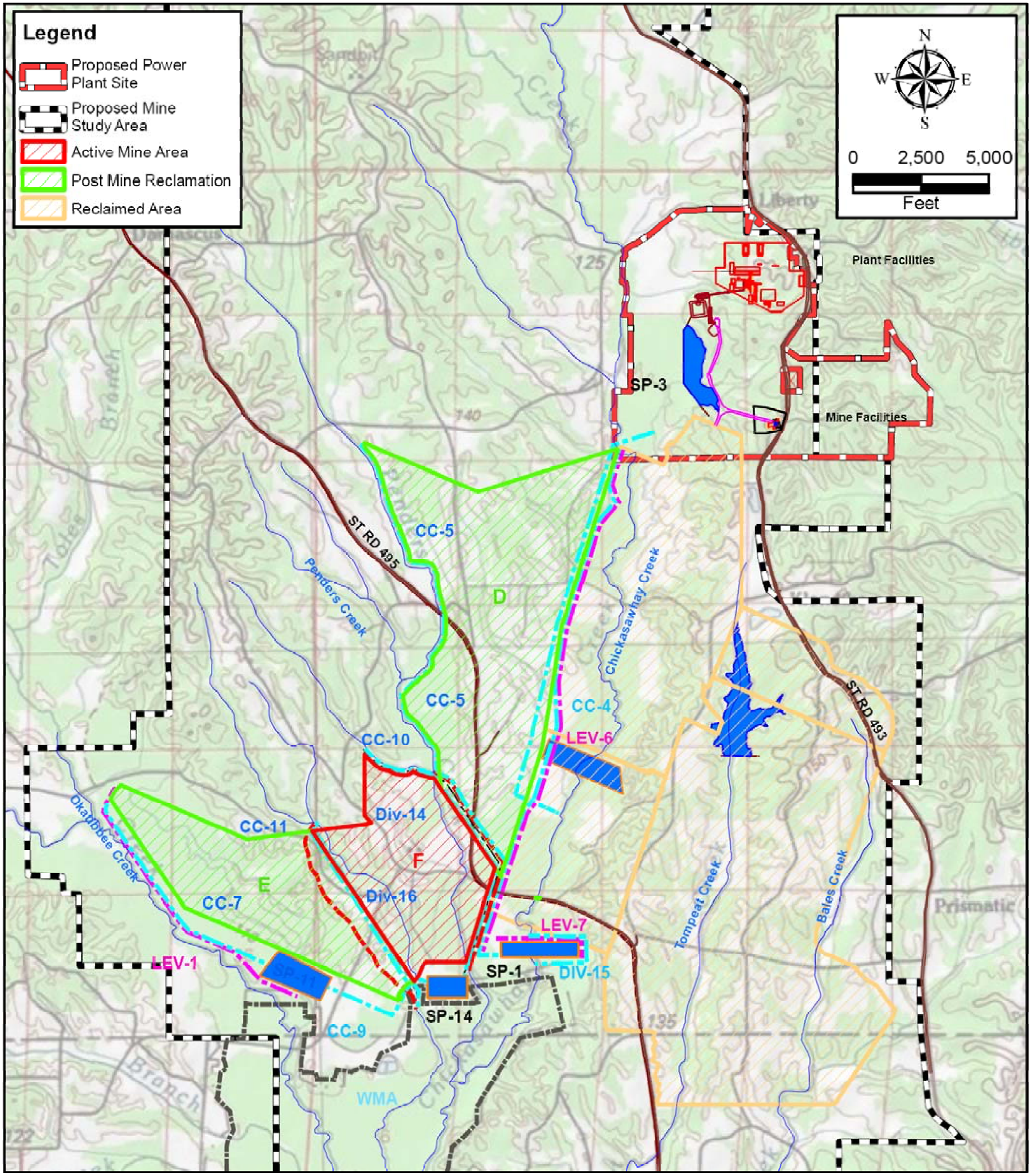

Figure 2.4-2f. Liberty Fuels Mine: Block F

Sources: NACC, 2009. ECT, 2009.

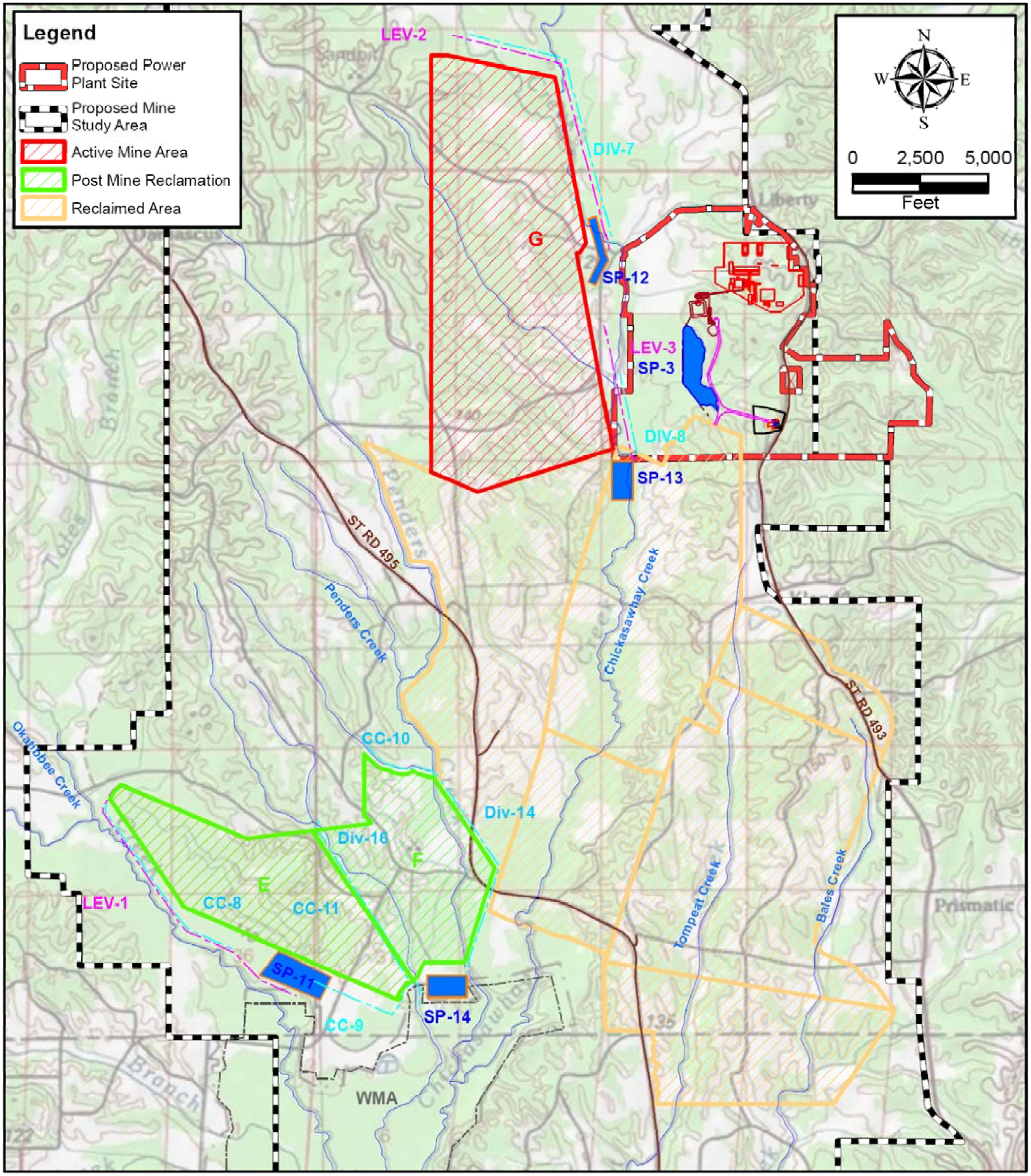

Figure 2.4-2g. Liberty Fuels Mine: Block G

Sources: NACC, 2009. ECT, 2009.

sedimentation ponds would be sized to contain runoff generated by a 10-year, 24-hour storm event. A total of seven additional sedimentation ponds could be constructed, with up to five of these built as below-grade excavated structures.

In addition, flood protection levees of up to 54,000 linear ft would also be constructed. These levees would be designed to protect active mining areas from flooding by existing streams. Design of the levees also would be based on storm-event modeling to determine flood elevations on Bales, Chickasawhay, and Okatibbee Creeks, where the levees are currently proposed. To meet MDEQ and USACE requirements, the levees would have to be located and designed to minimize increases in offsite flooding potential and in accordance with FEMA regulations.

Mine dewatering activities would be similar to those described in Subsection 2.3.2. The principal differences would be the volume of water managed. As mining advances in previously dewatered areas, mine pit inflow rates would decrease to 100 gpm, a reduction in half from the initial volume. Well yields would decrease to approximately 1 gpm from more than 700 gpm initially. As mining moves from dewatered blocks into new blocks, dewatering volumes would temporarily rise.

2.4.2.2 Reclamation and Mitigation

Minimum reclamation and mitigation requirements would be imposed on NACC throughout the duration of the MDEQ and USACE permits. Generally, the MDEQ permit would control reclamation, and wetlands and stream mitigation would be subject to **both** MDEQ and USACE permit conditions, if issued.

Upland Reclamation

Reclamation would be performed in accordance with the MDEQ SMCRA regulations. **Lands disturbed by mining operations must be reclaimed in accordance with these regulations.** As required by these regulations, reclamation would occur contemporaneously as mining advances across each mine block. Completion of physical reclamation efforts, defined as planting of the final vegetative cover, would occur approximately 3 years after lignite extraction (see Table 2.4-2).

NACC's operation of the Red Hills Mine provides an example of what the rate of reclamation would be at the Liberty Fuels mine. The MDEQ permit requires completion of physical reclamation efforts within 4.5 years at Red Hills. At Red Hills, the following mining and reclamation activities have occurred (NACC, 2009):

- Years of operation: 1998 to 2009.
- Total acres mined: approximately 1,045 acres.
- Total nonmined acres disturbed: approximately 324 acres.
- Average annual mining rate: approximately 100 acres/year.
- Total acres reclaimed (completion of all physical work): approximately 784 acres.
- Average annual reclamation rate: approximately 100 acres/year.
- Total reclamation acres under reclamation variance (i.e., haul roads, sumps, ponds, etc.): approximately 100 acres.
- Nonvariance acres to be reclaimed: approximately 485 acres.

Reclamation would begin by grading the overburden spoil. Then a minimum of 4 ft of oxidized suitable plant growth material would be spread across the reclamation area. Small, low-compaction bulldozers would be used to prepare the reclamation area for seeding. The type of vegetation planted on the reclaimed landscape would be controlled by the MDEQ permit and landowner preferences where the mine operator does not own the surface rights. Depending on the time of year and planting conditions, a temporary or permanent vegetative cover would be planted into the reclamation area. Loblolly pine trees would be typically planted the winter after permanent ground cover has been established in areas to become pine plantations.

Sedimentation ponds would not be reclaimed until the disturbed contributing watershed area is reclaimed, vegetation requirements are met, drainage entering the pond meets applicable effluent limitation standards, and/or other sedimentation ponds are located downstream. None of the proposed sedimentation ponds would **remain as permanent features.**

Figures 2.4-2a through 2.4-2g illustrate that the proposed mine plan will include mining disturbance where MS 493 and MS 495 are currently located. During EIS preparation consultations with DOE, NACC committed to reconstruction of both highways as part of the land reclamation process.

MDEQ SMCRA Regulations require return of the land surface to the approximate original contours. Based on information provided by NACC, up to 13 ft of lignite would be extracted to supply the IGCC gasifers. However, the overburden removed to expose the lignite would have an approximate 15-percent swell factor, which is the percentage expansion of the *in situ* volume when removed from its natural state. Because the swell factor would effectively offset the thickness of lignite extraction proposed, the net result would be land surface topography and elevations similar to existing conditions.

MDEQ SMCRA Regulations also require maintenance of the premining hydrologic balance and minimization of probable hydrologic consequences. Conformance with these requirements would require NACC to reestablish existing drainage patterns by contouring watersheds to their approximate premining boundaries and reclaiming stream valleys and floodplains to their approximate premining capacities and conditions. During preapplication consultations with USACE, NACC committed to restore all onsite streams disturbed by mining operations to their approximate premining locations.

Due to a lack of existing recoverable topsoil in the mine study area, NACC has indicated its intent to seek MDEQ approval to use oxidized overburden instead of native topsoil as an alternative, or topsoil substitute, in both uplands and wetlands. Subsection 4.2.3 addresses the effects of the proposed substitution.

Wetland Mitigation

Wetland mitigation would be conducted as required by the USACE permitting process. Both the type and magnitude of the mitigation required would be dependent on the type and magnitude of impacts authorized by USACE following completion of the avoidance and minimization analyses required under EPA Guidelines and a USACE/EPA Memorandum of Agreement more fully described in Chapter 7. All mitigation concerning impacts to wetlands would be properly coordinated by USACE during its evaluation process for Department of the Army permits.

With respect to the type of mitigation, USACE's 2008 Mitigation Rule establishes a hierarchy of preferred mitigation types, including mitigation bank credits, *in-lieu* fee fund programs, onsite in-kind restoration, onsite in-kind creation, etc. USACE's 2008 Mitigation Rule establishes the minimum quantity of mitigation required, in the case of the Mobile District, by using the WRAP to quantify the wetland functional loss attributed to each type of impact (e.g., forested versus herbaceous systems), as well as the increase attributed to the mitigation activity proposed. Under these rules, the mitigation quantity would be sufficient if the proposed mitigation activities result in an increase in wetland functional values that more than offset the losses attributed to the impacts, including consideration of temporal loss.

[Text from Draft EIS describing conceptual approach to wetland creation deleted.]**Lastly, the 2008 Mitigation Rule imposes minimum requirements for a formal mitigation plan approved by USACE that would be incorporated into the CWA Section 404 permit, if issued. The formal mitigation plan must provide, among other requirements, details on: (a) the legal instrument to be used to ensure the long-term protection of the mitigation site(s); (b) performance standards to determine whether the mitigation work is achieving the stated objectives; (c) a monitoring plan to determine if the mitigation work is on track to meet the performance standards; (d) a long-term plan for management of the mitigation project(s) after the performance standards have been met to achieve the long-term sustainability of the resources, including long-term financing plans; (e) an adaptive management plan to address unforeseen changes in site conditions or other components of the project; and (f) a financial assurance package to ensure a high level of confidence that the compensatory mitigation project will be successfully completed. Final determinations of the content of the NACC mitigation plan will be performed by USACE prior to permit issuance, if any.**

NACC is currently developing a mitigation plan that would be submitted to USACE for evaluation of conformance with the 2008 Mitigation Rule. Appendix P describes NACC's initial mitigation proposal. NACC's plan is based on the fact that the impacts to wetlands associated with the surface mining operation will not occur simultaneously, but rather over an approximate 40-year period. As a result, mitigation likewise would be conducted over time, rather than all at once.

Stream Mitigation

Stream mitigation would be conducted as required by the USACE permit**, if issued**. Both the type and magnitude of the mitigation required would be dependent on the type and magnitude of impacts authorized by USACE following completion of the avoidance and minimization analyses required under EPA Guidelines and a USACE/EPA Memorandum of Agreement more fully described in Chapter 7. Mitigation concerning impacts to streams will be coordinated during the USACE evaluation process.

USACE's Mobile District Stream Mitigation Standard Operating Procedures and Guidance provide the framework to be used to establish both the type and magnitude of mitigation required to offset the stream impacts authorized by the USACE permit, if any. The guidance provides a mechanism for calculating numerical losses due to impact and functional gains due to mitigation. The appropriateness of the type(s) of stream mitigation proposed by the mine operator would be evaluated on a case-by-case basis. Proposals by NACC, discussed conceptually in the following, would be evaluated as stream relocation mitigation under the Mobile Guidance (see Guidance, Subsection 5.1.1).

2.4.3 LINEAR FACILITIES

Permanent rights-of-way would be maintained for the proposed new transmission lines and associated substations, natural gas pipeline, reclaimed water supply pipeline from Meridian, and CO_2 pipeline**s**. Existing rights-of-way for the upgraded sections of transmission line would continue to be maintained as required by the

Southern Company Transmission Inspection Standards and the North American Electric Reliability Council. Operation of the linear facilities would generally include multiple types of inspections, as well as regularly scheduled mowing, clearing, herbicide application, and tree trimming. The gas and CO_2 pipelines would be mowed and inspected once per year per federal regulations.

All of the proposed and upgraded transmission lines would be maintained in accordance with the referenced policies, with the basic objective of ensuring every structure is inspected at least every 6 years. Mississippi Power's current transmission line inspection regime is as follows:

- Ground inspections are performed visually every 6 years by a contract employee immediately following mowing and clearing activities. The inspector installs and/or replaces guy markers and repairs broken ground wires as needed. Any critical problems are reported immediately; other deficiencies are noted in the Southern Transmission Operation & Maintenance (O&M) Program for routine follow-up.
- Ground line treatment inspections are performed on approximately 1/12 of Mississippi Power's wooden pole system every year. Although all design work has not been completed on the proposed transmission lines, it is not anticipated that any wooden poles would be used.
- Comprehensive walking inspections, also known as climbing inspections, are usually performed by company personnel or qualified linemen during normal operations and emergency repairs. Any critical problems are reported immediately; all other deficiencies are noted in the Southern Transmission O&M program for routine follow-up.
- Aerial inspections fall into two categories: (1) routine aerial inspections, and (2) comprehensive aerial inspections. Routine aerial inspections are performed by a contractor throughout the year on Mississippi Power's entire system, which would include the proposed facilities. If a critical situation is found, the inspector calls Mississippi Power to immediately notify them of the situation. All other situations are recorded in a monthly report. Although Southern Company Transmission Standards state that routine aerial inspections should be performed a minimum of four times per year, Mississippi Power routine aerial inspections occur a minimum of seven times per year. Southern Company Transmission Inspection Standards state that comprehensive aerial inspections are designed primarily for 230- and 500-kV structures. They are performed every 12 years for concrete structures and every 18 years for steel structures.

Vegetation control along the proposed and existing transmission rights-of-way would be accomplished through a 6-year cycle of mowing and clearing, as well as herbicide application:

Year	Activity
1	Mowing and clearing
2	Herbicide application
3	No action
4	Herbicide application
5	No action
6	No action
7	Start over (see Year 1)

A qualified representative would assess the condition of the right-of-way and review future planned activities to determine the scope of brush cutting that would be necessary. Rotary mowing equipment would be the preferred method for the complete cutting of all brush on the right-of-way. Hand cutting would be the preferred method in areas too wet to allow the use of low-ground-pressure rotary mowing equipment or where the scope of work calls for the selective removal of specific stems or the complete cutting of small areas of the right-of-way. Contract crews would remove all brush and debris from cultivated fields, pastures, waterways, lakes, ponds, ditches, roads, public road rights-of-way, trails, fences, and any other areas identified by Mississippi Power.

It might become necessary to intermittently trim trees and limbs that encroach on the right-of-way from the side. Mechanical side trimmers would be the preferred method for doing this, especially in rural areas where access and topography allow. Aerial lifts might be utilized in urban areas where trees have higher value and provide aesthetic benefit to the surrounding areas. Manual work, or climbing, would be limited to areas inaccessible to mechanized equipment.

Also, as a normal course of business, there might be times when it would be prudent to remove off-right-of-way trees that would have the potential to damage the proposed transmission lines. These are commonly referred to as *danger trees*. In Mississippi, a danger tree is defined as any tree, living or dead, which would pass within 5 ft of a conductor if it were to fall toward the conductor.

Herbicides would be applied to control vegetation that had the potential to interfere with electrical conductors or transmission structures and equipment. The scope of this work might range from the treatment of any and all vegetation on the right-of-way to the treatment of specific stems that might pose a threat to line reliability on selected segments of the right-of-way before the next scheduled treatment or vegetation management activity. The method and techniques of application would be determined by a qualified representative of Mississippi Power through field evaluation of the right-of-way to determine adjacent land use patterns, plant species, brush density, and soil and topographical characteristics of the area.

Herbicides might be applied to a right-of-way using a number of methods including aerial application, broadcast application, and low-volume application. Aerial application would typically be accomplished from a rotary-wing aircraft. The goal of aerial application would be to reduce the stem count and create an environment that would favor the establishment of low-growing species compatible with a transmission right-of-way.

Herbicides might also be broadcast evenly over the right-of-way in areas where brush density made it impractical to treat individual stems. The goal of broadcast application would be to reduce the stem count and create an environment that would favor the establishment of low-growing species that are compatible with a transmission right-of-way. After stem counts have been reduced to a manageable level by broadcast application, targeted applications using backpack sprayers or low-volume application might become the preferred method of application. Tall-growing stems with the potential to grow into electrical conductors would be individually treated to minimize the amount of herbicides used. Stems that were compatible with a transmission right-of-way would be left untreated.

Mississippi Power, and other operator/owners as appropriate, would also maintain the rights-of-way for the proposed pipelines in a similar fashion as the transmission lines to continuously provide easy access for maintenance, inspection, and emergency repairs. After placing the project pipelines in service, there would be regular tasks associated with their operation. Rights-of-way would be monitored to ensure the success of revegetation. To assure continued freedom of access, regular maintenance would include repairing washed-out or rutted areas, reseeding areas of unsuccessful vegetation growth, and mowing to prevent overgrowth. Regular maintenance would include patrolling the pipelines on a systematic basis, either on the ground or by air, to make sure that activities around the pipeline would not disturb or damage it in any way. Also, pipeline valves would be inspected and lubricated on a regularly scheduled maintenance interval. Signs would also be posted to indicate the location of the pipeline and provide a telephone number to call before any digging in the vicinity.

2.4.4 CONTINGENCY PLANS

The 4.5-year IGCC demonstration would most likely end in success. In that case, the commercial operation of the facilities would continue as planned and described previously. However, an unsuccessful demonstration remains a possible outcome. In this case, it is likely that either the power plant would be converted to a natural gas combined-cycle (NGCC) power plant, or it would continue commercial operation of the combined-cycle power-generating unit using the gasifiers to the extent possible, while using natural gas to serve the balance of the combined-cycle unit's requirements not met by the gasifiers. Under any foreseeable outcome, the expected operating life of the power plant facilities would remain 40 years.

Assuming an unsuccessful demonstration followed by commercial operation of the combined-cycle unit using natural gas exclusively, the power plant's use of coal would be replaced by increased use of natural gas. The plant would be capable of producing more electrical power due to less onsite demand (especially the gasification equipment). Lower emissions of most air pollutants from the power plant would result, and less water would be required for operations, as cooling water demand for NGCC project facilities would be reduced to 55 to 60 percent relative to IGCC due to the absence of demand by the gasification equipment. No carbon capture could be performed if the plant were operating on all natural gas. Less land would be required since less solid waste would be generated. For example, the potential future gasification ash management area on the east side of the site shown in Figure 2.1-**6** would not be needed. The gasifiers and related equipment would no longer be required and would likely be dismantled and removed from the site. The byproducts generated by the IGCC plant would also no longer be produced. The number of power plant workers during operations would drop to 28, because the gasifiers and related equipment would no longer be required.

The power plant would no longer require the lignite mine under this scenario, although the independent commercial operation of the mine could continue. Nonetheless, lignite coal shipments to the gasifiers would cease, which would likely reduce the scale of operations at the proposed mine.

The status of the lignite surface mine would be uncertain following an unsuccessful demonstration. If the power plant was converted to NGCC and Mississippi Power no longer purchased lignite from the mine, NACC would most likely actively pursue alternative customers/markets. Possible opportunities for an existing lignite mine would include supplying a traditional coal-fired power plant (e.g., pulverized coal) or activated carbon production (lignite is a good feedstock). If no other customer could be found, NACC would close the mine and perform all of the postmining reclamation activities that would be required under MDEQ SMCRA Regulations. Absent another lignite customer, the number of mine workers could drop from 213 down to 12 to 15, because the mine would no longer be required to support the IGCC plant, and the mine would be conducting final reclamation and maintenance of postmined lands.

Assuming unsuccessful demonstration followed by continued commercial operation of the combined-cycle unit using the gasifiers to the extent possible, while using natural gas for the balance, the proposed facilities' operations and resource requirements would fall between those described for successful demonstration and those for NGCC, just described. Less lignite and water would be used and less ash, filter cake, H_2SO_4, CO_2, and anhydrous ammonia would be produced. Less lignite would need to be delivered to the power plant than when the gasifiers were operating at availability levels planned during the demonstration period. The lignite mine would operate at a lesser rate to support the IGCC power plant, unless it could continue full-scale commercial operations for other customers. Disposal requirements and/or transportation offsite for commercial sale of H_2SO_4 and anhydrous ammonia would correspondingly be reduced. As with the NGCC outcome, during periods when the gasifiers were not operating, cooling water demand for project facilities would be almost 50 percent less than under the successful outcome. Also under this outcome, there would likely be somewhat fewer workers at the mine due to the lessened demand for lignite.

2.4.5 CLOSURE AND DECOMMISSIONING

Operation of the Kemper County IGCC Project and connected actions is projected to continue for 40 years. The actual operating life of these facilities could be more or less than 40 years; the factors that would determine whether the facility would operate, close temporarily, or be decommissioned permanently include, among others, the need for electricity, the economic competitiveness of the Kemper County IGCC Project in comparison to other sources of electricity available to Mississippi Power, work stoppages, storm damage, age of facility equipment, depletion of economically mineable lignite resources, and federal or state energy or environmental regulatory requirements.

2.4.5.1 Temporary Closure

Temporary closure **is defined as cessation of facility operations for a period of time greater than would be required for routine maintenance, overhaul, or replacement of major components of the IGCC facility. In the case of temporary closure, security for the project facilities would be maintained, and shutdown contingency plans would be implemented at the plant complex and the connected actions. At the IGCC facility, nonhazardous and hazardous materials would be managed in accordance with applicable regulations and BMPs. The reason for and expected duration of the temporary closure would influence decisions on whether to drain raw material tanks and return these materials to the supplying vendors or to maintain the facility in standby condition. Short duration temporary closures (e.g., those expected to last less than 1 year) would involve** ***standby*** **contingency plans, whereas longer duration temporary closures (e.g., those expected to last longer than 1 year) would implement** ***mothballing*** **contingency plans.** ***Standby*** **contingency plans would maintain the facilities in a ready-to-restart mode, whereas** ***mothballing*** **contingency plans would result in removal of raw materials and other steps that would preclude restarting the facilities on short notice.**

At the adjacent lignite mine, reclamation and mitigation on mined lands would continue until physical logistics (i.e., the land available for reclamation) prevented completion of additional areas until mining resumed. Water management would continue throughout the shutdown using the same facilities and BMPs employed during the preceding operating period. Mining equipment and facilities would be maintained in either a standby or mothballed condition in the same manner as the IGCC facilities depending upon the expected length of the shutdown.

2.4.5.2 Permanent Decommissioning

The planned operational life of the project is 40 years, but the IGCC facility conceivably could operate for a longer or shorter period, depending on economic considerations or other circumstances. For example, if the facility were to remain economically viable, it could operate for more than 40 years, which would defer environmental impacts associated with closure and the development of replacement power generating facilities. However, if the facility were to become economically nonviable before 40 years of operation, it could be closed permanently at an earlier time.

Regardless of when permanent closure occurs, a decommissioning plan specifying the appropriate closure procedures would be developed and implemented. As in the case of a temporary closure, security for the facility would be maintained on a 24-hour basis. During permanent closure, MDEQ, USACE, and other responsible agencies would be notified of the decommissioning schedule and plans. The procedures provided in the decommissioning plan would be designed to ensure public health and safety, environmental protection, and compliance with application regulations. Prior to the beginning of permanent closure activities, the decommissioning plan would be submitted to MDEQ for review and approval.

In general, the decommissioning plan for the Kemper County IGCC Project would address the following:

- Proposed decommissioning measures for the power plant and associated facilities constructed as part of the project, designation of equipment and appurtenances to be removed or to remain in place, as applicable.
- Site reclamation.
- Provisions for recycling facility components, collection and disposal of wastes, and resale of unused chemicals back to suppliers or other parties.
- Costs associated with the proposed decommissioning and reclamation activities and the source of funds to implement these activities.
- Conformance with applicable regulations and local/regional plans.

As it is not possible to predict the conditions that might exist at the time decommissioning decisions would be made, details would be developed and provided to MDEQ when more information was available.

At the adjacent lignite mine, reclamation would continue for 2 years to complete reclamation of all mined and disturbed areas, as shown on Table 2.4-1. Demolition of mine facilities would depend on whether other postmining economic uses would be economically viable at that time (e.g., the mine offices, warehouse, and mobile equipment maintenance facilities). NACC would continue with all ongoing reclamation and performance functions, including phased bond release, as required by the MDEQ SMCRA Regulations. Similar to Mississippi power, NACC would submit closure plans to MDEQ, USACE, and other responsible regulatory agencies for approval prior to implementation.

The upgraded electrical transmission grid would remain in service. The reclaimed water and CO_2 pipelines could remain in service or could be removed, depending on future potential uses of these facilities.

Table 2.5-1. Principal Full Load Operating Characteristics of the Proposed Kemper County IGCC Project*

Operating Characteristics	Nominal Value/Range
Generating capacity (MW) (net)†	582
Capacity factor (%)‡	85
Power production (MWh/yr)	4.3×10^6
Coal consumption (tpy)§◊	4.2×10^6 to 4.3×10^6
Natural gas consumption (10^6 scf/yr)**◊◊	5,800
Fuel oil consumption (10^3 gal/yr)**	124
Water requirements	
Reclaimed water (MGD)	6.2 to 6.9
Nonpotable ground water (MGD)	0.0 to 0.7
Reclaimed gasifier water (MGD)	1.0
Potable ground water (MGD)	0.003
Air emissions (tpy)‡‡	
SO_2◊	570 to 590
H_2SO_4	55
NO_x◊	1,800 to 1,900
PM⊗	**480 to 500**
PM_{10}◊	450 to 470
CO◊	890 to 980
VOCs◊	130 to 150
Ammonia	**184**
CO_2 emissions (tpy)◊ §§	1.8×10^6 to 2.6×10^6
Process wastewater (gpm)	0
Solid wastes (10^3 tpy)	
Filter cake††	3 to 15
Byproducts (10^3 tpy)	
CO_2◊	2,500 to 3,500
Anhydrous ammonia◊	21 to 22
Gasification ash◊	550 to 560
H_2SO_4◊	132 to 139

Note: MWh/yr = megawatt-hour per year.

*All values estimated based on stated capacity factors and average operating conditions using syngas and not meant to be representative of any specific time period.
◊Range estimates the characteristics expected when operating between 50- and 67-percent carbon capture on an annual basis.
†Generating capacity represents full load with duct burners firing.
‡Capacity factor is percentage of energy output during period of time compared to energy that would have been produced if equipment operated continuously at maximum power throughout entire period.
§Based on lignite coal from Liberty Fuels Mine in Mississippi with an average heating value.
**Assuming ten plant startups per year.
◊◊Assuming constant use of duct burners at stated capacity factor.
††Range includes process water supply cases with and without supplemental ground water from the Massive Sand aquifer.
‡‡Potential facilitywide emissions with IGCC operating on syngas at stated capacity factor.
§§Average CO_2 emissions from IGCC operating on syngas with continuous duct burner operation at stated capacity factor. Continuous duct burner firing contributes approximately 0.3×10^6 tpy to the total CO_2 emissions presented. Continuous duct burner firing CO_2 emissions presented to provide upper bound of potential operating conditions.
⊗Noncombustion sources contribute to particulates greater than PM_{10}, e.g., material handling, fugitive dust from roadways, etc.

Source: SCS, 2009.

Table 2.5-2. Summary of Expected Land Area Requirements

Location	Acres
Power plant	**700**
Onsite coal handling and mine operation facilities	350
Surface lignite mine area	<12,000
Natural gas pipeline	<50
New electrical transmission lines and substations	1,000
Reclaimed water pipeline	185
CO_2 pipelines	**500**
Total	**<14,785**

Sources: SCS, 2009; NACC, 2009; ECT, 2009.

2.5 RESOURCE REQUIREMENTS

Table 2.5-1 summarizes the operating characteristics, including resource requirements, for the proposed IGCC facilities.

2.5.1 LAND AREA REQUIREMENTS

Figure 2.2-1 showed the power plant site and all of the connected actions. Each of these would require land. Table 2.5-2 summarizes the expected land area requirements by component (all entries are approximate).

Figure 2.5-1 shows areas of the power plant site that would potentially be impacted by construction of various onsite facilities. The IGCC power plant and other associated permanent facilities would occupy a total of up to approximately 550 acres of the 1,650-acre power plant site. The 550 acres include the main gasification and power generation equipment, reclaimed water makeup pond, stormwater management facilities, cooling towers, flares, byproduct and ash storage areas, buildings and roads, and onsite portions of pipelines and transmission lines. Approximately 200 more acres of land would be required during construction for equipment/material laydown, storage, assembly of site-fabricated components, staging of material, a parking lot to accommodate construction workers' vehicles, facilities to be used by the construction workforce (i.e., offices and sanitary facilities), and buffer areas.

Some mining-related facilities would be located on the power plant site. The permanent (e.g., **lignite** handling and processing) and temporary (portion of initial mine area and construction staging) land use associated with the mine would total approximately 350 acres.

The study area for the proposed surface mine is approximately 31,000 acres, which includes approximately 1,400 acres within the boundary of the power plant site. Approximately 40 percent of the land within these 31,000 acres would be secured for mining and mining-related uses through leases or purchases. The land would either be secured from the surface landowner or the tract would not be mined or disturbed by mining impacts**; no land would be taken by NACC through eminent domain**. In addition, churches that are in use and dedicated cemeteries would be mined around and remain undisturbed.

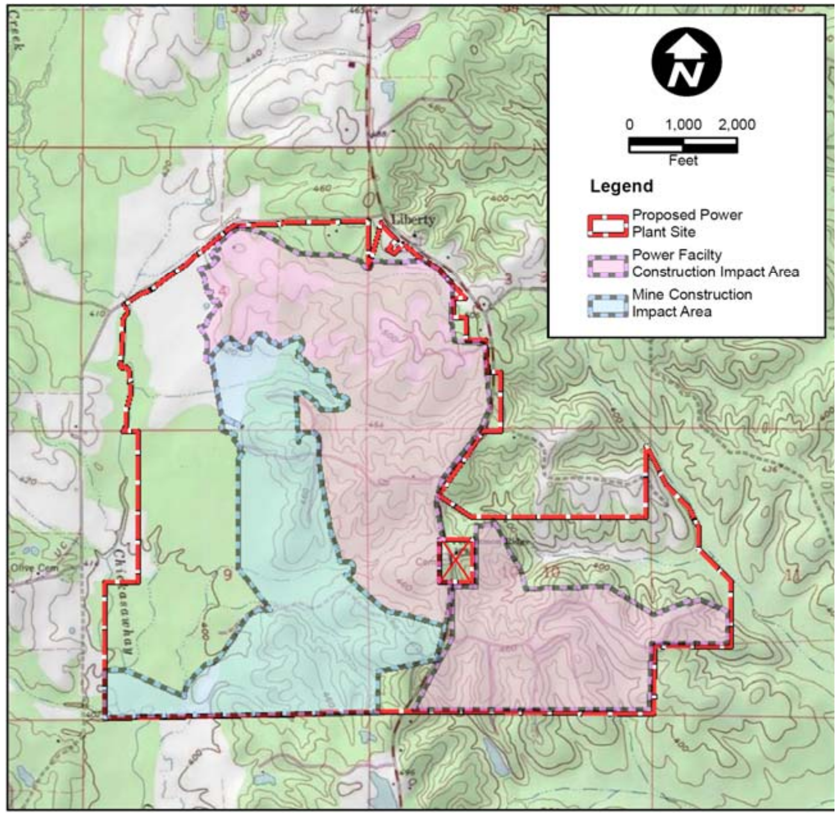

Figure 2.5-1. Areas of Kemper County IGCC Project Site Potentially Impacted

Sources: SCS, 2009. NACC, 2009. ECT, 2009.

As discussed previously (see Table 2.4-2 and related text), during the proposed 40-year life of mine, an average of 275 acres per year would be disturbed by lignite mining. Disturbed acres associated with mining over the 40-year period would total approximately **12,275** acres**, of which approximately 10,225 acres would be mined (see Table 2.4-1)**. However, the number of acres in a disturbed state at any given time would range from approximately 1,300 to 1,900 from 2014 through 2054.

Each of the linear facilities would have permanent land requirements as well as temporary needs for land during construction. The totals given in Table 2.5-2 reflect the approximate permanent new rights-of-way required for each facility (existing rights-of-way of transmission lines that would be upgraded are not included as these would not represent a new land requirement). Additional land would be required temporarily for equipment staging during construction. In addition, each linear facility would require some land for permanent, new access roads; the roads would be needed during construction, but would also be used for facility access for maintenance. More detailed engineering studies, which would be completed closer to facility construction, would be needed to estimate access road land requirements. However, the land requirements would be consistent with standard practices for siting such linear facilities and would not likely change the estimates given in Table 2.5-2 by any significant amounts.

2.5.2 WATER REQUIREMENTS

Potable water would be used during construction of the proposed power plant facilities for various purposes including personal consumption and sanitation**. Potable water would be provided by the local utility during both construction and operation. Water from small, permanent shallow wells located on the plant site would provide fresh water from the Lower Wilcox aquifer for** concrete formulation, preparation of other mixtures needed to construct the facilities, equipment washdown, general cleaning, dust suppression, and fire protection. Portable toilets would minimize requirements for additional **potable**/sanitary water during construction. Potable uses would consume an estimated 3,000 gallons per day (gpd).

Figure 2.5-2 presents a simplified process water balance diagram for the proposed IGCC facilities. When operating on syngas the 10-cell gasification system cooling tower and the 12-cell combined-cycle unit cooling tower would need approximately 5,000 gpm of water as makeup (based on annual requirements). This would replace cooling tower evaporative losses and blowdown (i.e., water discharged from the cooling tower to limit the concentration of total dissolved solids [TDS]). Approximately 55 percent of the cooling water demand would result from the combined-cycle unit's operation, while the remaining 45 percent would be attributable to the gasification facilities. Approximately another 13 to 14 gpm of water droplets would escape beyond the cooling towers' drift water eliminators to the atmosphere. Water conservation measures would include recycling process wastewater streams from both the gasifier and combined-cycle systems to the cooling towers.

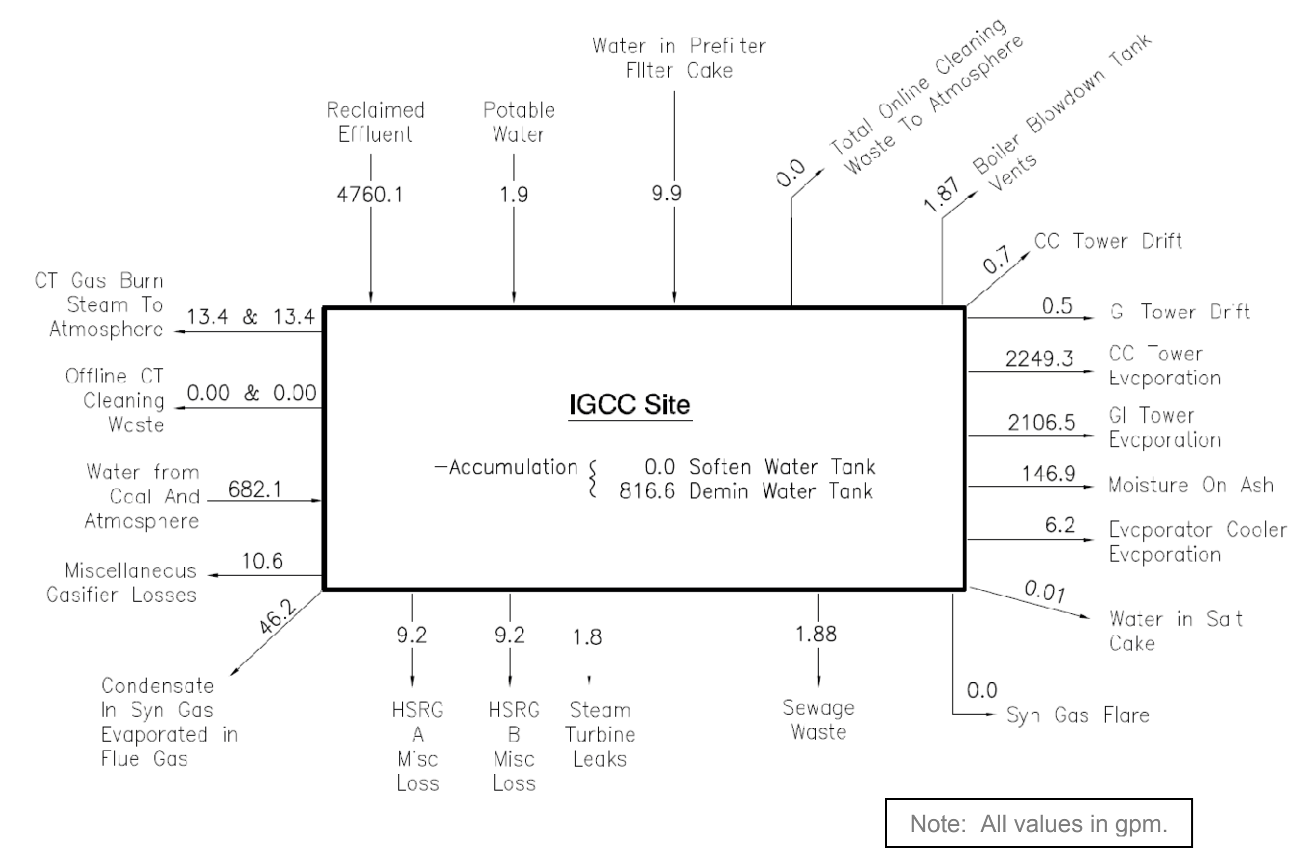

Figure 2.5-2. Overall IGCC Plant Water Balance
Sources: SCS, 2009. ECT, 2009.

Reclaimed water from two POTWs (Meridian and East Meridian) would supply the principal nonpotable water requirements for the IGCC power plant. Moisture from the lignite coal and recycled process water would also be collected and used to supplement the nonpotable supply. If necessary, ground water from the nonpotable Massive Sand aquifer would also be available. The main water uses would be cooling of both the gasification and combined-cycle systems, along with other service water needs, including boiler makeup. Most water consumption would result from cooling tower evaporation. As discussed elsewhere, recycling of various internal plant wastewater streams would occur wherever possible to reduce overall demands for new supply.

Reclaimed effluent from Meridian would be expected to supply up to an average of 6.9 MGD by 2015. This supply would be supplemented with approximately 0.98 MGD of water reclaimed from the gasifier process. Together, these sources would be expected to fully satisfy the nonpotable demands of the proposed IGCC facility. Reclaimed water from Meridian would be transported to the site via a reclaimed water pipeline, as discussed previously in Subsection 2.2.4. In the event of a shortfall in the amount of water available from the POTW water sources, additional power plant water could be supplied from an onsite well drilled to approximately 3,300 ft bls into the Massive Sand aquifer. This well and a backup well would each have the nominal capacity to withdraw approximately 930 gpm.

Reclaimed effluent from the two Meridian POTWs would supply the reservoir (surge pond) located on the portion of the site **south of the power plant footprint** (see Figure 2.1-**6**). This water would then be pumped to the IGCC power plant as needed. The onsite reservoir would provide a supply of water that would be available in the event of short-term disruptions or reductions in flow from the POTWs. (**Nonpotable g**round water could also supplement plant water supplies on a short-term basis, as noted previously, but its poorer quality would make it much less desirable.) Based on a preliminary design of the onsite water storage reservoir, it would cover approximately **90** acres and would have a volume of approximately 500 million gallons. An earthen dam would be constructed with a top of dam elevation of 4**55** ft. The overall dam height would be approximately **4**3 ft. The maximum high water elevation would be **443** ft, and the low water elevation would be **419** ft.

Table 2.5-3 presents raw water quality information for both the POTW and ground water sources. Table 3.7-5 will provide additional information on ground water quality. As shown in Table 2.5-3, the ground water from the onsite Massive Sand aquifer test well was found to have a high concentration of TDS. The implications of this are discussed in Subsections 2.7.2.1 and 4.4.1.

Table 2.5-3. Estimated Makeup Supply Water Characteristics

Constituent	Reclaimed Effluent	Massive Sand Aquifer
TSS (mg/L)	11	37
TDS (mg/L)	251	23,000
pH (s.u.)	6.5 to 8.4	6.9
Copper (mg/L)	0.006	0.003

Note: TSS = total suspended solids.
TDS = total dissolved solids
mg/L = milligram per liter.
s.u. = standard unit.

Sources: SCS, 2009.
ECT, 2009.

The main Meridian wastewater treatment plant was expanded to its present configuration in 1982. There is one National Pollutant Discharge Elimination System (NPDES)-permitted discharge, designated as Outfall 001, from the plant into Sowashee Creek. This water is treated to secondary standards. During periods of heavy rainfall, the Meridian treatment plant receives volumes in excess of its treatment capability. These excess volumes are routed through a series of three aerated ponds and a settling basin, then, after chlorination, to the final discharge pipe and outfall (this would be considered treatment to primary standards). Mississippi Power would draw from both sources of treated effluent at the main plant (i.e., use effluent treated to primary standards on some occasions, as well as that treated to secondary standards). In preparation for use in the cooling towers, the reclaimed water from Meridian may be filtered, chlorinated, and the pH adjusted with H_2SO_4. Alternatively, the reclaimed water may be chlorinated and softened via a cold lime softener prior to addition to the cooling towers. The process chosen would depend on future water analyses developed as the plant design progressed.

Chemicals for biocide, scaling, and corrosion inhibition would be injected into the cooling tower water. Chlorine would **either** be fed continuously **or in batch doses** into the system as a biocide. H_2SO_4 would be injected to reduce alkalinity, thereby controlling scaling. Calcium, phosphate, and silica scale inhibitors would likely be used in the cooling water also.

During construction of the mine-related facilities, water would be required for personal potable consumption and sanitation, concrete formulation, equipment washdown, dust suppression, fire protection, general cleaning, and construction of facilities including but not limited to pond dams, haul and access roads, buildings, service areas, and parking areas. Nonpotable water for construction activities would be obtained from existing livestock watering ponds and tanks that would be disturbed or removed by the mining and mine related activities. **Fresh** water **needs** associated with construction and mine operation would be obtained from ground water wells drilled onsite.

During mine operation, water for operations, dust suppression, fire protection, cleaning, sanitation, and equipment wash down would be obtained from onsite ground water wells, from existing stock ponds on land controlled by the mine, and from sediment ponds constructed by the mine operator for the management of surface and ground water.

The linear pipelines (natural gas, reclaimed water, CO_2) would require hydrostatic testing prior to being placed in operation. Water sufficient to fill and pressure test a section of pipeline would be required to conduct this testing. Typically, water for pressure testing would be supplied from nearby surface water sources and discharged to the right-of-way upon completion of each test.

2.5.3 FUEL AND OTHER MATERIAL REQUIREMENTS

The new gasifiers would operate on lignite, consuming a total of up to approximately 5.1 million tpy to produce syngas, based on continuous plant operation. At the expected IGCC plant annual capacity factor of 85 percent, the gasifiers would consume approximately 4.3 million tpy of lignite. The heating value of the lignite would average approximately 5,300 Btu/lb, and the average sulfur content would be approximately 1 percent. Table 2.5-4 presents a range for the expected composition of the lignite coal.

Table 2.5-4. Characteristics of Lignite Coal Expected to be Received for the Proposed Kemper County IGCC Project

Lignite Composition (As Received)		Average	Design Basis Range*	
			Minimum	Maximum
HHV	Btu/lb	5,290	4,765	5,872
Moisture	%	45.5	42.20	50.00
Ash	%	11.95	8.61	17.00
Sulfur	%	0.99	0.35	1.70
Nitrogen	%	0.48	0.33	0.61
Carbon	%	31.53	28.10	35.68
Hydrogen	%	1.98	1.73	2.40
Oxygen	%	7.57	4.17	10.47
Chlorine	ppm	116	45	295
Mercury	ppm	0.077	0.027	0.187
Fluorine	ppm	28.7	8.6	79.6

*Composition based on higher heating value. Table denotes ranges of individual constituents for all samples, not total compositions of any given sample.

Source: NACC, 2009.

The gas CTs would be capable of continuous, full-load operation firing either syngas or natural gas. Natural gas used in the CTs and duct burners, and potentially for coal gasifier startup, would be supplied by the new pipeline discussed previously. Natural gas would not be stored on the site. When operating on natural gas, the combined-cycle power-generating unit would consume approximately 4.8 million standard cubic feet (scf) of natural gas per hour at full load with duct burners operating.

Part of the CO_2 capture system would require use of solvent to strip off the CO_2 for concentration and compression. Although the solvent would be recycled and reused in the capture process, some continuous losses would occur. Accordingly, the IGCC plant would expect to consume approximately 10,000 to 11,000 gallons per year of solvent. In addition, small quantities of process chemicals, paints, degreasers, and lubricants would be consumed, similar to the volumes used at any industrial facility. Materials such as chlorine, H_2SO_4, anti-scalant and anti-foam chemicals, and sodium hydroxide would be used at the power plant. These materials would be stored in diked tanks or enclosures at the following approximate storage capacities: one 12,000-gallon tank of H_2SO_4 for cooling tower treatment, one 12,000-gallon tank of H_2SO_4 for raw water treatment, and one 12,000-gallon tank of caustic for raw water treatment; one 30,000-gallon tank of caustic for sour water treatment; and one 12,000-gallon tank of hypochlorite for water treatment. Also, the site would require a fuel oil tank of approximately 40,000 gallons, a solvent tank for AGR processes of 580,000 gallons, and a hydrogen peroxide tank for H_2SO_4 production of 12,000 gallons. In addition, several other tanks containing less than 500 gallons of specialty water treatment chemicals, such as corrosion inhibitors, would also be included in the plant design. The site would also likely have a number of smaller tanks and reservoirs for lubricating/machine oils to support various items of rotating equipment. These lubricating oil tanks would total approximately 10,000 gallons of storage capacity. Finally, approximately 1,200 cubic feet (ft^3) of alumina-based metal sulfide spheres **or sulfide activated carbon** used for mercury removal would be replaced approximately once every **2 to** 3 years. Approximately 13,300 ft^3 of activated carbon would be used for sour water treatment each month.

Diesel fuel, gasoline, and bulk lubricants would be stored in aboveground storage tanks (ASTs). Small amounts of specialty nonhazardous lubricants might be stored in smaller containers, such as 55-gallon drums. Equipment fuels and lubricants would likely be stored near the mine office/shop complex. All ASTs and drum storage areas would be enclosed by secondary containment units to contain the 10-year, 24-hour rainfall event and spillage from leaks. ASTs would be checked by on-shift crews and inspected routinely for leaks, corrosion, and other maintenance problems in accordance with a site-specific spill prevention, control, and countermeasure (SPCC) plan.

The lignite mine would consume oils/lubricants, antifreeze, diesel fuel, gasoline, and flocculent. The volume of diesel and gasoline used would fluctuate from year to year but, on an annual basis, would generally be between 2 and 3 million gallons and between 40,000 and 45,000 gallons, respectively. In addition, the volume of oils/lubricants and antifreeze use would average, on an annual basis, between 70,000 and 90,000 gallons and between 8,000 and 9,000 gallons, respectively. Flocculent would be used in the sediment ponds as necessary to increase the rate at which the sediment settled out of the water prior to discharge authorization. It is anticipated that, at the peak of pond operation, up to 30,000 gallons of flocculent would be used annually (dependent upon the number of ponds constructed and the intensity, duration, and frequency of rainfall events). As with the IGCC power plant, small quantities of process chemicals, paints, degreasers, and lubricants would be consumed. Tank sizes for most of these fluids would typically range between 5,000 and 10,000 gallons. Diesel would probably be stored in tanks of between 50,000 and 250,000 gallons.

There would be small amounts of paints, cleaners, adhesives, and other chemicals in spray cans stored at the shop and in the mine warehouse for normal heavy equipment maintenance. Normally, less than 20 gallons of paint in pint, quart, gallon, or 5-gallon cans would be kept onsite. Spray cans of paints and cleaners would be kept in fireproof cabinets in the shop and would be completely used and decanted prior to disposal. Large vehicle and small rechargeable batteries would be recycled with a reputable battery recycler.

2.6 OUTPUTS, DISCHARGES, AND WASTES

Table 2.5-1 included a summary of the most noteworthy discharges and wastes for the proposed power plant facilities.

2.6.1 AIR EMISSIONS

During construction of the IGCC plant, mine, and linear facilities, air emissions would result principally from two sources. First, workers' vehicles, heavy construction vehicles, delivery trucks, diesel generators, and other machinery and tools would generate mobile source and area source emissions of NO_x, volatile organic compounds (VOCs), and other typical products of combustion. Second, fugitive dust would result from land disturbance activities including excavation, soil storage, and clearing and grading earthwork.

During operation of the proposed IGCC plant, a number of sources would emit varying types and quantities of air pollutants (Appendix C provides details). Handling and storage of coal and gasification ash would generate fugitive particulate emissions. Coal would be delivered from the adjacent mine areas by trucks traveling on plant haul roads. The coal would be dumped into a hopper located within a stilling shed equipped with wet suppression. Also, key drop points and crushers would be equipped with water sprays and/or foggers. Much of the coal handling operation would be conducted in full to partial enclosures. Baghouses would be used at the milling and drying operations and crushed coal storage silos.

Gasification ash conveyors would be enclosed, and ash would be sprayed with water to reduce potential fugitive dust emissions during handling. The ash would be delivered from the ash loading area to designated storage or disposal areas by trucks traveling on plant haul roads.

Fugitive emissions of gaseous compounds could be generated from the facilities due to leaks from equipment such as valves, compressor seals, and flanges. These emissions would be minimized by proper maintenance practices. In addition, area gas detectors would be used to alert plant staff of fugitive gas emissions.

The WSA system would have the potential to emit NO_x, SO_2, and H_2SO_4 mist. Thermal NO_x would be generated in the process during the oxidation of the H_2S-rich acid gas stream to SO_2. A small fraction of the SO_2 produced in this process would not be further oxidized (to SO_3 and ultimately H_2SO_4) and would be released as SO_2 through the process vent stack. H_2SO_4 mist would be controlled using a mist eliminator; however, a small amount would be released through the process vent stack.

The facility would also include ancillary equipment that would potentially contribute air emissions. These sources would include the two cooling towers, AGR process vents, and miscellaneous combustion sources. These other combustion sources would include emergency fire pump engines and an auxiliary boiler. These sources would have the potential to release combustion byproducts including NO_x, VOC, and CO along with other trace emissions. The cooling towers would have the potential to release PM. The AGR process **startup/shutdown** vents would **be used to vent AGR process gases during periods of startup and shutdown of the AGR process. The AGR process gases would primarily consist of CO_2; however, they would also contain** low concentrations of CO and trace sulfur compounds. **During emergency conditions (such as trips of the CO_2 com-**

pressors, pipeline malfunction, etc.), or at the operator's discretion, the AGR process gases that would otherwise be compressed and fed into the CO_2 pipelines would be vented through the IGCC stacks.

Most emissions would result from combustion of syngas in the gas CTs during normal operations. The exhaust gas would be released to the atmosphere via the 325-ft HRSG stacks. Table 2.6-1 presents HRSG stack emissions at full load; annual emissions in this table are conservatively based on continuous year-round operation (100-percent capacity factor). Table 2.6-1 also presents the range of expected short-term rates for CO_2 capture between 50 and 67 percent. The principal pollutants would be SO_2, NO_x, PM, CO, and VOCs. **The IGCC would be equipped with SCR for reduction of NO_x. The SCR would be operated at all times during natural gas combustion. Additionally, the facility would test the long-term feasibility of SCR use during syngas combustion.The SCR is expected to be tested at NO_x control efficiencies of between 50 to 80 percent. The NO_x emissions during syngas combustion that are presented in Table 2.6-1 and evaluated in Chapter 4 of the EIS are conservatively based on no SCR operations.** Trace emissions of other products of combustion would include formaldehyde, toluene, xylene, carbon disulfide, acetaldehyde, mercury, beryllium, benzene, arsenic, and others. The list of trace compounds present in flue gas from syngas combustion is based on measurements made at the Louisiana Gasification Technology IGCC project (Radian, 1995). Flue gas would also include CO_2 and other GHGs (see Section 6.1 for additional discussion).

Table 2.6-1. Anticipated Maximum Air Emissions from Each HRSG Stack*

Pollutant	Short-Term Syngas (lb/hr)†	Short-Term Natural Gas (lb/hr)†	Maximum Potential Annual (tpy)‡
SO_2	14 to 15	1.9	62 to 66
PM/PM_{10}	52 to 55	24	228 to 241
CO	105 to 117	158	692
CO◊	**380 to 392**	**NA**	**NA**
NO_x	210 to 226	39	920 to 990
VOC	18 to 19	21	92
Reduced sulfur compounds⊗	**7.65**	**NA**	**<10**
H_2SO_4 mist	1.8 to 2.0	0.3	7.9 to 8.8
Ammonia	**21**	**21**	**92**
Lead§	0.013	—	0.057
Antimony	0.013	—	0.056
Arsenic	0.0098	—	0.043
Beryllium	0.0030	—	0.013
Cadmium	0.014	—	0.060
Chromium	0.012	—	0.054
Cobalt	0.0026	—	0.012
Manganese	0.014	—	0.061
Mercury	0.0037	—	0.016
Nickel	0.018	—	0.080
Phosphorous	0.011	—	0.049
Selenium	0.014	—	0.061
Acenapthalene	0.000085	—	0.00037
Acetaldehyde	0.023	0.13	0.59
Acrolein	0.0022	0.017	0.076
Benzene	0.022	0.057	0.25
Benzo(a)anthracene	0.0000075	—	0.000033
Benzo(e)pyrene	0.000018	—	0.000079
Benzo(g,h,i)perylene	0.000031	—	0.00014
CS_2	0.15	—	0.64
COS and H_2S	**7.5**	**—**	**4.3**
Ethylbenzene	0.01	0.071	0.31
Formaldehyde	0.10	0.35	1.5
2-Methylnapthalene	0.0012	—	0.0053
Napthalene	0.0016	0.0020	0.0086
Polynuclear aromatic hydrocarbons	0.00019	0.0015	0.0064
Toluene	0.027	0.21	0.92
Xylenes	0.026.0	0.20	0.88

*All emissions estimates based on worst-case operating scenarios, typically resulting from full-load operation with duct burner firing.

†The short-termed emission rates presented reflect the range associated with CO_2 capture of from 50 to 67 percent for criteria pollutants and H_2SO_4 and the maximum for the HAPs.

‡Annual emissions conservatively assume continuous, year-round operation using higher of syngas or natural gas hourly emission rate.

◊**Emissions for CO when AGR is vented through IGCC stacks.**

§The difference in emission rates between a CO_2 capture rate of 50 and 67 percent for the pollutants listed in this table from lead to xylenes is insignificant, and therefore no range is presented.

⊗**The facility's PSD permit limits facilitywide emissions of reduced sulfur compounds to less than 10 tpy. Estimated short-term emission rates of reduced sulfur compounds consist of the combined carbon disulfide (CS_2), COS, and H_2S rates.**

Sources: Mississippi Power, 2009a. SCS, 2009. ECT, 2010.

Water droplets would also escape from the cooling towers and would constitute particulate emissions. These droplets would contain some dissolved salts, which could be deposited as the droplets evaporate. Drift eliminators would minimize these emissions.

Air emissions would also be released through the startup stack and flares. During gasifier startups, exhaust gas would be released through the startup stack, and syngas would be combusted in the flare (see Subsection 2.1.2.8). Synthesis gas and gasification process gases might also be directed to the flares during malfunction, breakdown, or upset conditions such as trips of the CT/HRSG system or gasification processes to allow safe release of gases during recovery from such conditions. The flare might also be used to combust various process gases during normal operations of the gasifier, such as pressure relief valves. The duration of syngas combustion would vary depending on the type of upset.

There would be no stationary sources of particulates within the proposed life-of-mine boundary. All emissions would occur as a result of fugitive dust from haulroads, stockpiles, and exposed mine soils. The high annual precipitation and the high-moisture content of the overburden being moved would likely provide some natural control of fugitive dust emissions.

In addition to the natural control of fugitive dust emissions, fall distances at transfer or material dumping points would be minimized to the greatest extent practical. Personal safety, machinery clearance, and line-of-sight capabilities of machine operators would dictate minimum fall distances. Fugitive dust emissions would be controlled from haul roads and access roads by water trucks. Chemical dust suppression and road construction amendments, such as calcium chloride and lignum sulfonate, or other approved road bases, including gasification ash (subject to agency approval), might be used.

Other particulate emission controls would include:

- Scraping and compacting unpaved roads to stabilize the surface as necessary.
- Restricting unauthorized vehicles on other than established roads.
- Minimizing the area of disturbed land.
- Prompt revegetation of regraded lands.
- Reducing the length of time between initial disturbance and revegetation or other soil stabilization.
- Maintenance of lignite stockpiles. All lignite that is stored in lignite stockpiles would be sealed and compacted by both rubber-tired and track-type dozers. By sealing the pile, conditions conducive for spontaneous combustion would be minimized. The lignite stockpiles would continuously be monitored, and if smoldering or burning lignite is observed, it would be promptly extinguished. In addition, all water trucks located onsite would be equipped with water/foam cannons for the specific use of fighting fires. Using the program outlined, the Red Hills Mine has had very few smoldering lignite events. For these cases, the lignite was extinguished by digging up the smoldering lignite and promptly spreading it out on the surface. It should be noted that the lignite to be mined at the Liberty Mine is in the same formation that is being mined at Red Hills.

2.6.2 LIQUID DISCHARGES

2.6.2.1 IGCC Power Plant

During power plant operation, the proposed IGCC facilities would produce various process wastewaters, all of which would be discharged to treatment and/or reuse systems. No process wastewater streams or water treatment discharges would be released from the power plant site. The principal water management requirements necessary to ensure no process liquids leave the site would be maximum reuse of all water streams. Between 800 and 2,000 gpm of low-volume wastes (e.g., boiler blowdown, sour water cleanup wastes, oil/water separator wastes, condensation from the air compressors, gasifier-stripped water, evaporative cooler blowdown, brine concentrator, and crystallizer condensate) would be conveyed to the cooling tower recycle basin to supplement cooling tower makeup. Depending on plant operation, between 150 and 350 gpm of demineralizer first-pass reverse osmosis concentrate would be piped to a wastewater treatment facility for evaporation. Condensate from the wastewater treatment facility would be recycled back to the cooling tower basin. The resulting salt cake would be disposed of in an appropriate manner.

Potentially contaminated stormwater would be routed to conveyances and directed to onsite stormwater retention ponds. Runoff from areas associated with industrial activity, including the lignite storage area and equipment areas, would be routed for oil separation and suspended solids removal. Stormwater collected outside the developed areas of the power plant site would be discharged in accordance with an NPDES general stormwater permit.

Chemical tanks would be surrounded by secondary containment. Spilled chemicals would be neutralized in place, collected, and shipped offsite for proper disposal. Collected water containing oils (e.g., stormwater runoff, equipment washdown water) would be sent to an oil/water separator to remove the oil and then to the reclaim sump for reuse.

Domestic and sanitary wastewater generated by power plant operations personnel would be discharged to a new septic system and absorption field that would be constructed near the new facilities. The system would be designed to handle 3,000 gpd.

Chemical wastes would be generated from periodic cleaning of the HRSGs and turbines. These wastes would consist of alkaline and acidic cleaning solutions, turbine washwaters, and HRSG washwaters. These wastes likely would contain high concentrations of heavy metals. Chemical cleaning would be conducted by specialized contractors who would be responsible for removal of associated waste products from the site to an appropriate treatment, storage, or disposal facility.

2.6.2.2 Lignite Mine

Mine Drainage

Within the adjacent mine, the primary source of liquid discharges would result from surface water control structures. All surface drainage, including stormwater runoff, from disturbed areas would be passed through a sedimentation pond. A series of stormwater runoff control channels and sedimentation control ponds would be constructed prior to initiation of surface mining activities. As the mining advances, additional sedimentation control ponds would be constructed as needed to control runoff from disturbed areas and would meet discharge water quality standards. Approximate locations of these sedimentation ponds and other water control structures within the mine study area were shown on Figures 2.4-2a through 2.4-2g.

These mine sedimentation ponds would be designed, constructed, and maintained in accordance with the performance standard requirements of Section 5327 of the MDEQ SMCRA Regulations. The water quality of the ponds' contents would be monitored on a regular basis following storm events. When the water quality meets required effluent limitations, the contents would be discharged to the gated level. Between storm events, the ponds would be maintained at or below the gated level. Sedimentation ponds would not be removed until the disturbed area had been restored, the vegetation requirements had been met, the drainage entering the ponds met applicable effluent limitation standards, and/or new impoundments had been installed downstream. None of the presently conceived ponds would **remain** as permanent features.

In addition, clean-water diversions of Chickasawhay Creek, Bales Creek, portions of Pender's Creek, and their tributaries around the proposed mine boundaries and sedimentation ponds would be constructed. These diversions would **also** be regulated under the Liberty Fuels Mine mining permits required by MDEQ and USACE, if issued.

Domestic Wastewater

Sanitary waste from mine facilities would be processed and treated onsite and discharged into the local receiving streams if and as authorized by the facility's NPDES permit. A small, extended aeration package plant or an equivalent technology plant would be designed for the expected volume of effluent discharge. Effluent volume between 2,500 and 5,000 gpd would be expected. Portable chemical toilets would be located throughout the active mining area. These units would be rented and serviced by outside vendors. The wastewater generated from these units would be pumped out, treated, and disposed in accordance with state regulations.

Process Washwater

Wastewater from mining vehicle wash facilities would be treated through the sedimentation ponds, if and as authorized by the NPDES permit. Additional waste streams such as used oils, lubricants, or solvents would be recycled or undergo disposal in accordance with all local, state, and federal regulations. Secondary containment systems would be provided for fuel and lubricant storage areas and an SPCC plan would be developed and implemented for the site-specific mining operations, consistent with CWA requirements.

NPDES Permit Effluent Limits

NACC would need to obtain a federal NPDES permit to construct and operate its proposed lignite mine. Releases of water from the boundary of the active mine areas would be regulated by the permit, including the mine drainage released through sedimentation ponds, the domestic wastewater, process water generated at the mobile equipment maintenance facilities, and stormwater runoff from reclaimed lands not yet released from SMCRA bonding requirements.

The NPDES permit would impose the following numerical effluent limits on all water discharged from the mine as specified by 40 CFR 434:

- **pH = 6.0 to 9.0 s.u.**
- **Iron (total) = 3.0 mg/L, 30-day average.**
- **Iron (total) = 6.0 mg/L, daily maximum.**
- **Manganese (total) = 2.0 mg/L, 30-day average.**
- **Manganese (total) = 4.0 mg/L, daily maximum.**
- **TSS = 35.0 mg/L, 30-day average.**
- **TSS = 70.0 mg/L, daily maximum.**

The limits on iron, manganese, and TSS would not apply to any discharge caused by precipitation within a 24-hour period greater than a 10-year, 24-hour precipitation event (6.25 inches); only the pH effluent limits would apply to such discharges.

All water discharged would have to meet Mississippi water quality standards at the point of entry into the downstream receiving water bodies. Mine discharges also would have to be tested periodically and found to be nontoxic to aquatic life (i.e., macroinvertebrates and fish).

Projected Effluent Quality

Effluent discharged from the proposed Liberty Fuels Mine would be similar in quality to discharges from the currently operating Red Hills Mine, based on the similarity of geochemistry of the lignite seams to be mined and the similarity of mining methods at the two locations.

NACC provided 5 years of compliance monitoring data from the Red Hills Mine and supplemental analyses of metals contained in discharges from the Red Hills Mine (see Tables 2.6-2 and 2.6-3).

The data presented in Table 2.6-2 demonstrate that discharges from the Red Hills Mine are mildly alkaline, with pH ranging from 6.21 to 8.64 s.u., which indicates that acid mine drainage has not been generated by mining lignite in the Wilcox Group. Manganese levels in discharges measured between 0.01 and 0.76 mg/L, with all values well below the 40 CFR 434 limits of 2.0 mg/L (30-day average) and 4.0 mg/L (daily maximum). Iron values averaged approximately one-third the numerical effluent limits; however, maximum iron values did exceed the numerical effluent limits during one sampling event in 2006. The next highest iron level measured was 5.27 mg/L, which is below the daily maximum numerical effluent limit. TSS has increased over time; however, no exceedances of the 40 CFR 434 numerical limits have been measured, and the 2009 values averaged approximately two-thirds of the allowable levels.

Table 2.6-2. Consolidated Discharge Water Quality—Red Hills Mine, 2004 through 2009

Year		pH	Total Iron	Total Manganese	TSS	TDS
2005	Minimum	6.75	0.20	0.01	1	132
	Maximum	8.23	4.28	0.76	32	540
	Average	7.44	0.94	0.10	10.20	294.31
2006	Minimum	6.21	0.08	0.01	1	66
	Maximum	8.13	7.49	0.20	42	1,032
	Average	7.18	1.26	0.08	13.02	315.33
2007	Minimum	6.36	0.17	0.01	2	162
	Maximum	8.24	2.94	0.19	44	744
	Average	7.33	0.75	0.09	15.79	384.00
2008	Minimum	6.39	0.08	0.01	1	70
	Maximum	8.5	4.8	0.22	55	544
	Average	7.40	1.05	0.07	19.80	271.64
2009	Minimum	6.7	0.10	0.013	3	185
	Maximum	8.64	5.27	0.35	61	322
	Average	7.69	1.06	0.09	23.03	246.92
2005 through 2009	Minimum	6.21	0.08	0.01	1	66
	Maximum	8.64	7.49	0.76	61	1032
	Average	7.43	1.02	0.09	16.29	300.77

Source: NACC, 2010.

Table 2.6-3 presents data showing that concentrations of silver, arsenic, cadmium, selenium, thallium, and zinc are below the detection limit at Red Hills Mine, suggesting they would not be exceeded in discharges from the Liberty Fuels Mine. Chromium was measured essentially at the laboratory detection limit. Copper, nickel, and mercury were detected above the detection limit; however, the values measured are less than the Mississippi state water quality standards. Note also that mercury was reported in nanograms per liter (ng/L).

Table 2.6-3. Supplemental Discharge Water Quality Data—Red Hills Mine, December 2009

Analyte	Unit	Sample RC-1	Sample RC-2
Total silver	µg/L	< 0.100	< 0.100
Total arsenic	µg/L	< 0.500	< 0.500
Total calcium	mg/L	13.100	3.700
Total cadmium	µg/L	< 0.100	< 0.100
Total chromium	µg/L	1.03	< 1.000
Total copper	µg/L	0.972	0.654
Total iron	mg/L	1.070	1.120
Hardness as $CaCO_3$	mg/L	55.1	15.9
Total magnesium	mg/L	5.43	1.630
Total manganese		0.242	90.4
Total nickel		3.32	1.32
Total selenium		< 2.00	< 2.00
Total thallium		< 0.500	< 0.500
Total zinc		< 5.00	< 5.00
Resistivity	ohms/cm	5,380	1,720
TDS	mg/L	96	37
Total mercury	ng/L	3.57	3.01
Specific conductivity	µohms/cm	186	58

Note: RC-1 = outfall downstream of P-29-1.
RC-2 =outfall downstream of SP-4.

Source: NACC, 2010.

2.6.2.3 Linear Facilities

Liquid discharges from the linear projects would include stormwater and periodic discharges of water used for hydrostatic testing of the CO_2, natural gas, and reclaimed water pipelines. These discharges would be managed in accordance with NPDES permitting obligations.

2.6.3 BYPRODUCTS AND SOLID WASTES

2.6.3.1 Construction

During construction of the proposed power plant and the supporting facilities, potential waste would include earth and land clearing debris, metal scraps, electrical wiring and cable, surplus consumable materials (e.g., paints, greases, lubricants, and cleaning compounds), packaging materials, and office waste. **Prior to conducting any land clearing or demolition, surveys for regulated substances (e.g., oil drums, asbestos containing materials, and other regulated wastes) would be conducted. Should any be found, these materials would be managed in accordance with applicable regulations.** In general, the construction wastes would be typical of the construction of any large industrial facility. Any potentially reusable materials would be retained for future use, and the recyclable materials would periodically be collected and transferred to recycling facilities. Metal scraps unsuitable for reuse would be sold to scrap dealers, while the other remaining materials would be collected in dumpsters and periodically trucked offsite by a waste management contractor for disposal in a licensed landfill. Other materials would include packaging material (e.g., wooden pallets and crates), support cradles used for shipping of large vessels and heavy components, and cardboard and plastic packaging.

[Text from the Draft EIS regarding hazardous waste deleted.]

2.6.3.2 Operation

During operation of the proposed IGCC power plant facilities, the primary byproducts would be gasification ash, anhydrous ammonia, CO_2, and H_2SO_4. The gasification process would produce a total of approximately 75 tph of gasification ash from accumulation of noncombustible mineral material originally present in the lignite. The gasification ash would come from two sources: the gasifiers and the filter systems. The ash from the gasifiers would be larger, approximately 100 microns in diameter, have a carbon content typically less than 3 percent, and look similar to a dark colored sand. The gasifiers would produce approximately 25 tph, or 1,000 cubic feet per hour (ft^3/hr). The particulate from the filter system would be finer than the gasifier solids (typically around 20 microns). It would have a carbon content of approximately 15 to 20 percent; it would have a dark gray to black appearance and have the consistency of talcum powder. The flowrate of this particulate would be approximately 50 tph, or approximately 4,000 ft^3/hr.

Based on an 85-percent capacity factor, approximately 560,000 tons of ash would be produced annually. All ash would be depressurized and cooled before entering the atmospheric ash silo. Water would be added to the solids as necessary for dust control prior to being transported by truck. Both gasifier and filter ash would be transported by truck to the ash management unit located in the northern portion of the plant site along Liberty Road. The ash would be classified as industrial/special waste in the state of Mississippi, and the ash management unit would be subject to the permit requirements and regulations of MDEQ. To reduce long-term ash storage needs, Mississippi Power would try to market ash for beneficial use in industrial processes such as building roads, soil amendment, or for other uses as approved by MDEQ. Figure 2.1-**6** also shows a possible future ash disposal area on the portion of the site east of MS 493. This area would not be needed unless insufficient quantities of ash were sold.

Ash samples were collected from gasification tests conducted at the pilot-scale gasifier at the Power Systems Development Facility near Wilsonville, Alabama. These tests used a lignite feedstock mined from the Wilcox Group at the Red Hills, Mississippi, mine, which is expected to be similar to the lignite that would be produced for the proposed IGCC project. Although the ash generated in these tests involved lignite from a different mine and a pilot-scale gasifier, it is the most representative material available. Tests of these ash samples indicate that the gasification ash would meet toxicity requirements for nonhazardous material. There is no expectation that the ash would be ignitable, corrosive, or reactive Therefore, the ash would not be classified as hazardous. Table 2.6-**4** summarizes the results of the test gasification ash characterization.

Anhydrous ammonia (approximately 98.5- to 99.5-percent pure) would be produced as a byproduct of the lignite coal gasification process and stored in a pressure vessel. The ammonia would be produced from the gasifier at a rate of up to 70 tpd during normal operations. There will be a pressurized anhydrous ammonia tank(s) operating at approximately 300 pounds per square inch absolute (psia) and at ambient temperature. The tank(s) would be sized for 5 days' storage, or approximately 400 tons. Some

Table 2.6-4. Pilot-Scale Gasification Ash TCLP Data

	Coarse Ash		Fine Ash		Composite Sample*		
	Total Metals (mg/kg)	TCLP (mg/L)	Total Metals (mg/kg)	TCLP (mg/L)	Total Metals (mg/kg)	TCLP (mg/L)	TCLP Limits (mg/L)
Antimony	<4.8		<4.3		<9.8		
Arsenic	4.2	<0.020	38	0.042	34	0.043	5.0
Barium	410	1.1	1100	1.9	850	1.5	100
Beryllium	3.6		8.5		7.1		
Cadmium	<0.48	<0.0050	2.0	0.036	1.5	0.0071	1.0
Chromium	42	0.020	95	<0.010	84	<0.010	5.0
Cobalt	7.1		18		16		
Copper	100		230		160		
Mercury	<0.0038	<0.00056	0.0073	<0.00056	0.0052	<0.00056	0.2
Lead	4.3	<0.010	79	<0.010	52	<0.010	5.0
Nickel	22		48		42		
Selenium	2.0	<0.020	26	<0.020	17	0.042	1.0
Silver	<0.95	<0.010	<0.86	<0.010	<2.0	<0.010	5.0
Thallium	<1.9		<1.7		<3.9		
Vanadium	160		320		250		
Zinc	8.4		26		28		

Note: mg/kg = milligram per kilogram.
mg/L = milligram per liter.
TCLP = toxicity characteristic leaching procedure.

*Composite sample is 55-percent fine ash and 45-percent coarse ash by weight.

Source: SCS, 2009.

ammonia would be used onsite in the SCR process in the HRSGs, but the majority of it would be trucked offsite, marketed, and sold commercially. A conventional tanker truck holds approximately 18 tons of anhydrous ammonia, so there would be approximately four tanker trucks produced per day.

When operating on syngas, CO_2 would be captured, compressed, and marketed for EOR. The IGCC unit would capture approximately 9,600 tons of CO_2 per day on average. The CO_2 would be compressed and delivered to a dedicated pipeline interconnected with an existing CO_2 network serving regional oil producers.

The gas cleanup system would produce liquid H_2SO_4 approximately 93-percent pure. The quantity of H_2SO_4 produced would depend on the sulfur content of the coal. Under average conditions, approximately 450 tpd would be produced from the WSA system. If the worst-case (i.e., highest) percent sulfur lignite was being converted to syngas, H_2SO_4 production would rise to approximately 760 tpd. The H_2SO_4 would be stored as a liquid at ambient temperature and pressure. Onsite tanks would be sized for 10 days' storage under average conditions, or approximately 5,000-ton storage capacity. The H_2SO_4 would be commercial grade and would also be trucked offsite, marketed, and sold commercially. A conventional tanker truck will hold approximately 25 tons of H_2SO_4, so under average conditions, there would be 20 trucks per day. Under worst-case sulfur coal conditions, this would require up to 33 trucks per day.

Solid wastes from the power plant would include solids from water and wastewater treatment systems (e.g., sour water treatment), demineralizer resin beds, the filtration system in the sulfur process, used air inlet filters, and other maintenance-related wastes such as rags, broken and rusted metal and machine parts, defective or broken electrical materials, and empty containers. Spent activated carbon would likely be recycled. A filter cake would be produced by the brine crystallizer wastewater filter press. The filter cake would be the largest volume solid waste generated during IGCC operations. From 3,000 to 15,000 tpy would be produced, and it would be collected in a storage bin and trucked to an offsite solid waste disposal facility. Other nonhazardous solid wastes would also be transported offsite for disposal in a licensed landfill. Any waste determined to be hazardous under RCRA regulations would be transported offsite by a licensed contractor to a RCRA-permitted treatment and disposal facility or returned to the manufacturer for treatment and recycling.

The power plant would produce salt in rough proportion to the amount of the highly saline ground water used. The salt concentration in the ground water would be lowered to an acceptable level before using the water in the plant, and a salt cake would be produced. Since reclaimed water, which has a low TDS concentration (see Table 2.5-3), is anticipated to be available to meet the plant's needs and ground water would only be used infrequently, if ever, salt production over the life of the plant would likely be small. Figure 2.1-5 shows an area east of MS 493 for future salt disposal. Based on the reclaimed water supply plan, it is unlikely this area would be needed for salt disposal.

During the mining operation, clearing activities (pushing noncommercial trees and brush) and removing abandoned structures, such as old barns and houses, would generate solid waste. This waste could consist of brush, tree trunks and limbs, old lumber, waste tin, and roofing material. This waste could be eliminated by: (1) burning it, (2) disposing of the nonhazardous rubbish in a mined-out pit, or (3) hauling it offsite to a registered landfill. On an annual basis, this would be less than 500 tons. The mine would be handling approximately 50 million tons of overburden and lignite; thus, the rubbish would be an insignificant quantity. **Prior to conducting land clearing, surveys for the presence of regulated materials (e.g., petroleum drums, asbestos-containing materials, hazardous substances, etc.) would be conducted. Should these materials be present, the mine operator would manage disposal offsite in accordance with applicable regulations.**

In addition to process wastes, solid wastes generated during operation of both the power plant and mine would include used office materials and packaging materials. Most office and shop wastes would be placed in dumpsters for removal by a local waste disposal contractor for final disposal at a local landfill. These wastes would include lunchroom garbage, paper, cardboard, plastic packaging, and empty cans and bottles. The disposition of these items would be similar to that discussed previously for these materials during the construction period.

2.6.4 TOXIC AND HAZARDOUS MATERIALS

Construction and operation of the proposed power plant and supporting facilities would involve potentially toxic or hazardous materials and wastes generated from the typical industrial uses of paints, solvents, lubricating oils, and similar products. Any such wastes determined to be hazardous under RCRA regulations would be transported offsite by a licensed contractor to a RCRA-permitted treatment and disposal facility or returned to the manufacturer for treatment and recycling.

At the proposed IGCC plant, most liquid hydrocarbon streams would be recovered and processed to extinction in the gasifiers. Some spent liquid hydrocarbon streams of sufficiently high value would be sent offsite for mineral recovery and recycling. Used oils collected from the oil/water separator and used oil filters from the gas CTs would be transported offsite by a licensed contractor for recycling or disposal.

The proposed CO_2 capture system would require approximately 18,000 ft^3 of water gas shift catalyst, which would be replaced approximately every 2 years. The active metal on this catalyst would typically be cobalt with a molybdenum promoter. The base material would vary depending on the catalyst vendor. Approximately 2,500 ft^3 of alumina-based catalysts used to convert **COS** to hydrogen sulfide for sulfur removal would require replacement approximately once every 3 years. Both the water gas shift and **COS** catalysts would be regenerated and reused, to the extent possible. If it were not possible to regenerate these catalysts, they would be managed as hazardous waste, in which case a licensed hazardous waste contractor would remove these materials for offsite disposal.

Approximately 1,200 ft^3 of alumina-based metal sulfide spheres used for mercury removal would be replaced approximately every 3 years. These alumina and carbon materials would likely be characterized as hazardous waste. Accordingly, they would be managed, removed, and disposed by a licensed hazardous waste contractor. Up to approximately 13,300 ft^3 of activated carbon used for sour water treatment would be generated each month. This material would be removed from the units by the vendor and processed for regeneration and removal of the contaminants. Regenerated carbon would then be placed back into the treatment units. Recovered contaminants would be disposed of by the vendor or recycled. Finally, the WSA process would utilize approximately 25,000 ft^3 of alkali promoted vanadium catalyst to convert SO_2 to SO_3. This catalyst would be screened every 2 years, with approximately 20 percent of the total volume being replaced with fresh catalyst. Recovered catalyst would undergo disposal by the vendor or be recycled.

A filter cake would be generated by the sulfur and CO_2 removal processes. This cake would be principally composed of piping residue with some metallic constituents present. The amount produced would be small, likely less than 100 pounds (lb) per day. If the filter cake were characterized as a hazardous waste, it would be managed, removed, and disposed of by a licensed hazardous waste contractor.

During operation of the proposed mine, waste paints, solvents, oil, fuel, cleaners, adhesives, lubricants, greases, or other similar wastes would be **managed** in accordance with all applicable hazardous waste, nonhazardous waste, and/or used-oil regulations. Oil would be drained into approved containers in the shop during regular maintenance of heavy equipment. Used oil would then be collected, stored in an AST, and provided to a responsible used-oil dealer for recycling. Used grease from draglines and shovels might also be mixed with oil for recycling or would be sent to an offsite facility that could specifically recycle used greases.

Under RCRA, the mining operations would likely qualify as a conditionally exempt small-quantity generator of hazardous wastes. It is expected that approximately 200 gallons per year of solvent would be used, primarily in the shop for cleaning purposes, in parts washing stations and aerosol spray cans. A recycling program would be in place to handle the solvent waste stream. A licensed hazardous waste disposal contractor would be used where necessary to remove larger quantities of hazardous waste, if generated.

The power plant and mine facilities would implement a program to reduce, reuse, and recycle materials to the extent practicable. All light bulbs would be treated as hazardous waste, if appropriate, and transported to properly licensed facilities for disposal. The facilities would have an SPCC plan (40 CFR 112) addressing the accidental release of materials to the environment.

2.7 ALTERNATIVES

The purposes and needs for a federal action determine the reasonable alternatives for the NEPA process. Congress established the CCPI Program with a specific purpose—to accelerate commercial deployment of advanced coal-based technologies that can generate cleaner, reliable, and affordable electricity in the United States by authorizing DOE to provide financial assistance to private projects selected through a competitive process. Similarly, Congress established a loan guarantee program to encourage private entities to pursue energy projects that “avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases” and “employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued” (Section 1703[a][1], 42 United States Code (USC) § 16513). DOE’s preferred alternative (to provide cost-shared funding and a loan guarantee) would fulfill the purposes and meet the needs of these programs by demonstrating the viability of the energy technologies (i.e., coal gasification, syngas cleanup systems, and supporting infrastructure integrated into a combined-cycle power-generating unit). The preferred alternative would result in the impacts, both beneficial and adverse, discussed in this EIS. Any reasonable alternative to the proposed action must also be capable of satisfying the purposes and needs of these two federal programs. In addition, it must be an alternative that was the subject of an application that a private proponent submitted to DOE that meets the requirements of the CCPI and loan guarantee programs. The project proponent provides the majority of funding and bears the primary responsibility for designing and executing the project. DOE’s primary action as to these programs is to decide which projects it will give assistance to from among the eligible proposals submitted. Unlike a project initiated and operated by DOE, it does not have the ability to make decisions concerning the location, layout, design, or other features of the project. In other words, DOE must select among the eligible projects submitted to it; DOE cannot design its own project and compel a private entity to implement. DOE uses the procedures established in its NEPA regulations, specifically those in Section 1021.216, to identify and consider the potential environmental impacts of the eligible projects submitted in making its selections.

In addition to the analysis and consideration of reasonable alternatives that meet the federal goals, CEQ NEPA regulation 40 CFR 1502.14[d] requires that DOE analyze and consider a no-action alternative. The no-action alternative in this context represents a decision by DOE to refrain from providing financial assistance and a loan guarantee to the project. For purposes of this EIS, DOE assumes that such a decision would prevent the project from being built, and analysis of the impacts of the no-action alternative described in the EIS are based on this assumption. In actuality, there is some possibility that Mississippi Power and SCS would proceed with the project without federal participation. The no-action alternative also represents what would occur if DOE had selected another project or decided not to assist any projects with financial assistance or loan guarantees. As is the case with most no-action alternatives, it would not meet the purpose and need for federal action as established by Congress through the CCPI and loan guarantee programs.

2.7.1 NO-ACTION ALTERNATIVE

Under the no-action alternative, DOE would not provide cost-shared funding or a loan guarantee for the design, construction, and demonstration of the proposed Kemper County IGCC Project. Without DOE participation, Southern Company and Mississippi Power could pursue two options. First, Mississippi Power could continue with the proposed IGCC project without federal participation. DOE believes that option is unlikely, because the financial risks and costs of deploying a new type of IGCC power system are significant. Furthermore, the costs and risks of adding a carbon capture system and pipeline would probably exceed the revenue from sales of CO_2 for use in the EOR industry. In any event, if the project applicants were to proceed with the project but without DOE participation, the direct, indirect, and cumulative impacts would be essentially the same as the proposed action that is analyzed in this EIS.

Second, the applicants could choose not to pursue the IGCC project and, instead, meet future energy and capacity needs from other sources. Under this scenario, the proposed IGCC facility would not be built. It is also unlikely that the lignite mine would be built nor the linear facilities associated with the proposed project. As a consequence, none of the direct impacts associated with the preferred alternative would occur, whether adverse or beneficial. In addition, the chances for more rapid commercialization of the gasification facilities (alone or integrated with the combined-cycle facilities to form IGCC technology) would diminish, because utilities and industries tend to prefer known and demonstrated technologies. Moreover, this scenario would not achieve the CCPI program's goal of accelerating commercial deployment of advanced coal-based technologies that can generate clean, reliable, and affordable electricity in the United States. Similarly, this outcome would not contribute to the loan guarantee program's goals of advancing energy projects that "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases" and "employ new or significantly improved technologies."

2.7.2 PROJECT-SPECIFIC ALTERNATIVES UNDER CONSIDERATION

While they do not constitute alternatives to DOE's decision whether to provide cost-shared funding or a loan guarantee, Mississippi Power is considering certain project-specific alternatives that would affect the project's potential environmental impacts. The impacts of the project-specific alternatives are analyzed in this EIS.

2.7.2.1 Alternative Sources of Water Supply

As discussed in Subsection 2.5.2, the planned source of the IGCC power plant's cooling and other non-potable water is reclaimed effluent from two POTWs located in Meridian, south of the plant site. The reclaimed water would be delivered to the site via pipelines. Some nonpotable ground water might be used in the infrequent cases when too little effluent was available.

Mississippi's ground water regulations require the new power generating facilities use nonpotable water. The principal ground water source available at the IGCC project site would be saline ground water withdrawn from the Massive Sand aquifer. Ground water from the deep Massive Sand aquifer could supply all the power plant's requirements, and Mississippi Power and SCS investigated this option to the extent of installing a test supply well and conducting a pumping test (refer to Section 3.4). While the aquifer was determined to be capable of yielding sufficient amounts of water for plant requirements (see Section 4.4), the quality of the water was found to be very poor, with a TDS concentration of approximately 23,000 ppm. The use of this ground water as the sole source would create a number of engineering and other issues in the IGCC plant systems and would also have adverse environmental effects.

First, withdrawing and piping water of such high salinity would impose costs for materials and maintenance. Well casings would deteriorate and require abandoning and replacing wells more frequently than otherwise, for example. Affected plant systems would need to be designed and engineered especially to make use of this water.

Second, the high solids concentration would result in large quantities of solid waste (principally salt cake) requiring management and disposal. Both added costs as well as potential environmental impacts associated with disposal (e.g., landfilling) would result.

Third, use of this saline water in the IGCC plant's cooling towers would result in some amount of salt drift. As discussed in Section 4.4, the deposition of cooling tower salt drift would potentially impact some sensitive vegetation on the plant site and in the immediate surroundings. Salt deposited on the ground would also have some potential to impact local surface waters via stormwater runoff.

To summarize, ground water would be an option for providing the sole supply for the IGCC plant's needs for water. However, the use of reclaimed water is currently considered to be preferable, barring unforeseen limitations on its availability, as the engineering issues, costs, and environmental impacts of ground water use would be greater.

2.7.2.2 Alternative Linear Facility Routes

As described in Section 2.2, the new linear facilities that the project would require are a natural gas pipeline, electrical transmission lines, a reclaimed effluent pipeline, and the CO_2 pipeline**s**. The preferred route for the natural gas pipeline was determined by reviewing the shortest route (running directly east from the power plant site to the existing large-diameter gas supply pipeline), then surveying and field-inspecting the route to adjust for areas to avoid (e.g., wetlands) as referenced in Mississippi Power's procedures.

Mississippi Power employed its Transmission Line Routing and Design Procedure (Mississippi Power, undated) in the selection of routes for the other linear facilities. For the longer new transmission lines and CO_2 pipeline**s**, at least two alternative routes were developed and evaluated using available mapping and aerial photographs to select the primary route. The alternative routes were identified and evaluated considering factors that included:

- Avoidance of built-up and densely developed areas, including residential areas, buildings, bridges, airports, cemeteries, landfills, and irrigation systems.
- Avoidance of environmentally sensitive or problematic areas, such as wetlands, rivers, lakes, landfills, and contaminated sites; known locations of culturally or historically significant sites or areas; and known locations of sensitive species or their habitats.
- Avoidance of difficult terrain or other conditions that would pose engineering, construction, operating, or economic concerns or maintenance and reliability issues.
- Use of existing rights-of-way.

Once the primary routes were identified, a preliminary route was developed. Noteworthy features of some of the preliminary routes are:

- The routes for new transmission lines generally approximate the shortest distance between the required end points, thus minimizing length and land affected while still avoiding built-up or sensitive areas.
- Routes of the West Feeder and CO_2 pipelines coincide to minimize impacts.
- Routes of the East Feeder and the reclaimed water pipeline would coincide to minimize impacts.
- The portion of the CO_2 pipeline route south of the end point of the West Feeder is adjacent and parallel to an existing Mississippi Power transmission line right-of-way to minimize impacts.

Importantly, Mississippi Power might revise or amend the route for one or more of its linear facilities, although the analysis of impacts provided herein should cover any impacts resulting from any such revisions to those routes. Moreover, Mississippi Power might not control final routing authority regarding the CO_2 pipelines, and other private entities ultimately responsible for owning and operating that line to transport CO_2 might require some changes to the route. Again, it is not expected that any such route changes would result in the aggregate to any significant differences in the analysis of impacts discussed in this document.

2.7.2.3 Alternative Levels of CO_2 Capture

Through the course of project development, Mississippi Power has considered a range of alternative levels of CO_2 capture: 25, 50, 67, and greater than 67 percent (Mississippi Power, 2009; SCS, 2009). As stated in DOE's Notice of Intent, Mississippi Power initially had planned to capture 25 percent of the CO_2 in the syngas. At a 25-percent capture rate, either an amine removal system or another solvent-based system could be used for CO_2 removal without a water-gas-shift reactor. This rate would have represented a significant advancement in commercial scale CO_2 capture in the power industry, but it would not meet the *California Standard* or natural gas equivalency. Mississippi Power determined that higher capture rates, if achievable, would improve the viability of the project.

In subsequent discussions with MDEQ, Mississippi Public Service Commission (PSC), and DOE, Mississippi Power decided that a minimum of 50-percent capture would be economically feasible. A PSD permit application based on this level of capture was submitted to MDEQ in May 2009. A 50-percent capture rate would be equivalent to the California Standard emission rate of 1,100 pounds of carbon dioxide per megawatt-hour (lb CO_2/MWh). At this rate the annual CO_2 emissions would be approximately 2.6 million tons. The CO_2 removal system would require a minimum of a single train of water-gas-shift reactors and a Selexol (or similar) system for CO_2 removal. Parasitic load would be 90 to 100 MW, or approximately 12 to 15 percent of the gross plant capacity.

More recently, Mississippi Power developed a design case based on 67-percent CO_2 capture, which would result in CO_2 emissions from the plant approximately equivalent to emissions from a natural gas-fired combined-cycle unit generating the same amount of power. A modified PSD permit application based on this design case was submitted to MDEQ in September 2009. A 67-percent capture rate (the design basis for this EIS) would yield an emission rate of approximately 800 lb CO_2/MWh and would be considered natural gas equivalency. At this rate the annual CO_2 emissions would be approximately 1.8 million tons. The CO_2 removal process to achieve this level of capture would require two trains of water-gas-shift reactors and a Selexol (or similar) system for CO_2 removal. Parasitic load would be 100 to 115 MW, or approximately 14 to 17 percent of the plant's gross capacity.

Mississippi Power also evaluated higher rates of CO_2 capture. A theoretical limit on the amount of CO_2 removal would be approximately 80 percent, with 90-percent water-gas-shift and a Selexol (or similar) system for CO_2 removal. This high level of removal would require polishers or other additional equipment. The major concern with higher removal rates was that gas turbine design and operation at higher hydrogen contents of syngas has not evolved sufficiently to confidently design the plant for commercial operation. Also, Mississippi Power determined that capture levels higher than 67 percent would not be economically feasible (i.e., the ability to provide power to utility customers at a reasonable price), as additional process equipment and step changes in parasitic load would be necessary.

Although the 67-percent capture case is expected to be the normal operating condition for the project, operating characteristics covering the range from 50 to 67 percent were presented in Table 2.5-1. While higher CO_2 removal rates would further reduce some collateral emissions at the same time, more lignite coal would be consumed to meet the higher capture target, and somewhat greater emissions overall would be expected for the two cases. Since the air quality modeling and other environmental impacts were already completed for the 50-percent capture case, these impacts are provided in this EIS (Chapter 4) to represent the impacts associated with this alternative level of CO_2 capture.

2.7.3 PROJECT ALTERNATIVES CONSIDERED BY DOE AND THE PROJECT'S PROPONENTS

2.7.3.1 Alternative Project Applications Considered by DOE in the CCPI Round 2 Procurement Process

The project satisfies the purposes and needs for federal action as set forth in the CCPI funding opportunity announcement that DOE issued in February 2004 (Section 1.2). Program factors considered in DOE's project selection process included the desirability of projects that collectively represent a diversity of technologies, use of a broad range of United States' coals, and locations throughout the United States. DOE did not constrain the proposals with regard to site or technology, except that projects must primarily use coal to be eligible for funding.

DOE also considered the potential environmental impacts of the projects submitted for consideration in CCPI Round 2. The applications included responses to an environmental questionnaire (Section 1.7). The responses contained information about the site-specific environmental, health, safety, and socioeconomic impacts of each project. Based on the evaluation criteria discussed in Section 1.2, including environmental impacts, DOE selected four projects proposing four different energy technologies, including the technology proposed for the Kemper County IGCC Project, for possible award of financial assistance for a portion of the project's costs.

Because DOE's role in these private projects is limited to providing cost-shared funding and a loan guarantee to a project, DOE's decision is limited to selecting or rejecting the project as proposed by the proponent. DOE may, however, approve the cost-shared funding or loan guarantee contingent upon incorporating mitigation to reduce potential impacts of the project as proposed by the applicant.

2.7.3.2 Alternative Sites

Mississippi Power's power plant site selection effort and its decision to locate an IGCC facility in Kemper County were completed approximately 2 years prior to Southern Company's request to DOE to transfer the funding for a CCPI demonstration project from the cancelled project in Orlando, Florida. Mississippi Power's proposal for transferring the financial assistance to this project concluded that the only reasonable alternative was the Kemper County project because it was already underway and had the ability to meet the eligibility requirements of the CCPI Round 2 funding opportunity. By the time Mississippi Power proposed the Kemper project as a replacement for the Orlando Project in the CCPI program, Mississippi Power had already entered into formal agreements with the IRS regarding the Kemper project's eligibility for tax credits.

Well before Southern Company sought to transfer the financial assistance available under CCPI Round 2 to this project, DOE had already certified, and the IRS had already qualified, the Kemper County project under the EPAct05. Specifically, in June 2006, Southern Company applied to DOE to be certified to the IRS for certain clean coal investment tax credits. As part of that certification, DOE required Southern Company to demonstrate that it had ownership or control over the specific site where it intended to apply those credits. In accordance with the process for qualifying for available investment tax credits, DOE certified this project, including the specific site to the IRS. In November 2006, the IRS accepted the project and proposed a closing agreement with Southern Company conditioning the tax credits on, among other things, locating the project in Kemper County. Without the investment tax credits, Mississippi's Kemper County project may not be economically feasible.

Prior to locating its project in Kemper County and seeking investment tax credits for it, Mississippi Power considered a range of generating options, including a variety of technologies and fuels. As its planning review progressed, Mississippi Power identified lignite as an abundant, economic, local resource that would provide consistent long-term fuel pricing, reliability of supply, and diversification of Mississippi Power's fuel stock. Further evaluation of lignite revealed that due to the higher transportation costs associated this lower heating value fuel, only a mine-mouth location would be economically viable for a lignite-fired unit. Accordingly, Mississippi Power focused its review of possible sites on the following:

- Location of accessible lignite reserves near Mississippi Power's service territory (see Figure 2.7-1).
- Proximity to infrastructure, including Mississippi Power's electrical transmission facilities and natural gas supply.
- Topography, including the location of floodplains and wetlands.
- Available open space.

Working with NACC, Mississippi Power identified three general areas in Kemper County that might be suitable: the proposed location and two additional areas a few miles to the north. NACC compared the lignite reserve at the proposed mine location to the other potential areas. Criteria used in this comparison included the following:

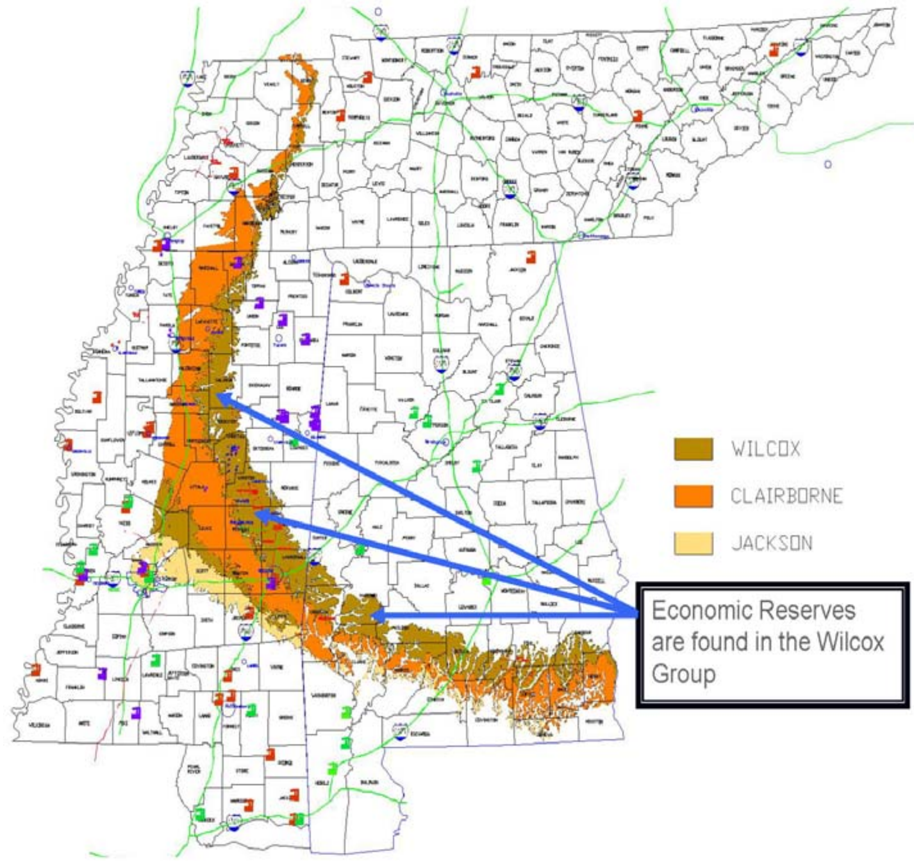

Figure 2.7-1. Lignite Bearing Strata of Mississippi, Alabama, and Tennessee

Source: MARIS, 2009.

- Size of recoverable reserve sufficient to supply a nominal 500- to 600-MW generation facility for at least 40 years.
- Economy of mining, based on the total depth of overburden (nonlignite materials above and between seams of lignite), thickness of the lignite seams, quality of the lignite, competing surface land uses, and initial mine development costs.
- Location of the reserve in relation to connecting the proposed generation facility to the electrical distribution system.
- Reliability of data available indicating the presence of sufficient economic reserves.

In each of these categories, the site of the proposed reserve—the southernmost area of the three candidates—ranked equal to or higher than other potential reserve sites for this particular project. The southernmost site was also selected since it would be most proximate to Mississippi Power service territory and existing infrastructure and would require the shortest linear support facilities. Otherwise, the three sites were generally similar in terms of topography, wetlands, and floodplains. Thus, Mississippi Power viewed the ability to minimize the nominal lengths of the linear support facilities as a means of reducing the project's overall cost and environmental impact. Furthermore, NACC had also independently identified the southernmost area in 2002 as a potential mine location and had already gathered specific developmental information on the site.

Two possible locations of an immediately adjacent power plant were examined: one on the western side and one on the eastern side of the lignite seam. Based on available open space, topography, including floodplains and apparent wetlands, and proximity to infrastructure, Mississippi Power selected the proposed site on the east side in early 2006.

At the request of USACE, Mississippi Power and NACC have prepared a summary of their joint assessment of alternative sites (Appendix T). Both companies have taken practicable and reasonable steps to avoid and minimize the impacts to aquatic resources associated with the proposed Kemper County IGCC Project. If approved by USACE and MDEQ, mitigation for unavoidable impacts would be provided in accordance with the required Compensatory Mitigation Rule. Further details on potential mitigation can be found in Subsection 7.1.2. USACE will evaluate whether the preferred site alternative: (a) is the least environmentally damaging alternative that meets the overall project purpose, (b) is financially feasible, (c) is the most practicable, and (d) demonstrates meaningful avoidance and minimization of impacts to aquatic resources in accordance with 33 CFR 320.4(b) and as required by 40 CFR 230.10 (i.e., the 404[b][1] guidelines) regarding avoidance and minimization of impacts to aquatic resources during its final evaluation of the Mississippi Power and NACC Section 404 permit applications.

In summary, once lignite was identified as the fuel/feedstock for the facility, the location of accessible and economic lignite reserves near Mississippi Power's service territory governed the location of the mine. The project proponent selected the site for the power plant in early 2006 based on proximity to infrastructure, topography, including avoidance of floodplains and wetlands, and available open space. Later in 2006, Mississippi Power applied for and received DOE and IRS approval for investment tax credits for a lignite-fired IGCC power plant at this site. Finally, in 2008, Southern Company proposed to DOE that it transfer the financial assistance originally awarded to the project in Orlando to this project, already sited in Kemper County.

2.7.3.3 Alternative Power Generation Technologies

Other power generation technologies were considered but dismissed because they did not meet the CCPI program's purpose and needs or those of the applicant. The proposed project was selected to demonstrate coal gasification, syngas cleanup systems, and supporting infrastructure, which would be integrated with the combined-cycle power-generating unit to form IGCC technology. Other CCPI projects were selected to demonstrate other coal-based technologies. The projects not selected under the CCPI Program were DOE's alternatives prior to the time of selection and were considered at that point in DOE's decision-making process.

The use of other technologies and approaches not applicable to coal (e.g., natural gas, wind power, hydropower, nuclear power, solar energy, and conservation) would not meet the CCPI program's goal or loan guarantee program's goal of accelerating commercial deployment of advanced coal-based technologies that can generate clean, reliable, and affordable electricity in the United States. Furthermore, no funds appropriated by Congress to DOE under the CCPI program can be spent on technologies that do not use coal as a primary power source. DOE distributes financial support provided by Congress to demonstrate alternative technologies, such as solar energy, through other programs.

Mississippi Power could use the native lignite in coal-based technologies other than IGCC. The alternative technologies include subcritical pulverized coal (PC), supercritical PC, and ultra-supercritical PC. As discussed previously, the IGCC application was selected by Mississippi Power as the best option in accordance with the company's generation planning process. As noted previously, Mississippi Power's closing agreement with the IRS under EPAct05 for investment tax credits conditions receipt of those credits on the use of IGCC technology and lignite. Notably, both EPA (2006) and DOE (2007a) have examined the comparative costs and performance of IGCC and these other technologies. Both studies developed performance characteristics based on standard, commercial plant designs at generic greenfield sites. Neither study lends itself perfectly to the Kemper IGCC project since they examine only oxygen-blown gasifiers (as opposed to air-blown TRIG^{TM}). And the reports present relatively less comparative information addressing low-rank coals like lignite, given the very limited use of these coals in IGCC units to date. However, the main purpose of the CCPI program is to facilitate the movement of promising technologies to the commercial marketplace through demonstrations like Kemper, where a low-rank coal would be demonstrated in just such a promising new technology.

Table 2.7-1 presents a summary of the comparisons found in the EPA report for lignite and subbituminous coals. All of the information shown in this table assumes no capture of CO_2 emissions. EPA adds discussion of CO_2 capture and sequestration and compares IGCC to supercritical PC, noting that the "comparison highlights the potential advantage for IGCC to capture and sequester CO_2 at significantly lower costs than PC technologies."

Table 2.7-2 summarizes the results of DOE's comparisons. DOE examined cases for three existing IGCC systems (again, all oxygen-blown) and subcritical and supercritical PC, all with and without CO_2 capture. These were among the conclusions contained in the DOE report:

- Energy Efficiency—IGCC has higher efficiency than the PC cases, even without CO_2 capture. The addition of CO_2 capture to the PC cases has a much greater detrimental impact on efficiency than CO_2 capture in the IGCC cases.
- Water Use—IGCC requires less water than the PC technologies, and the addition of CO_2 capture increases IGCC water use much less than for PC.
- Cost—PC plants have lower capital costs than IGCC absent CO_2 capture; adding capture gives IGCC the cost advantage. PC has the lowest levelized cost of electricity (LCOE) (including fixed, variable, fuel, and capital costs) without capture, while the higher capture costs for PC technologies flip the cost advantage to IGCC.
- Environmental Performance—IGCC has lower overall air pollutant emissions than PC.

The information presented in the EPA report generally supports all of the conclusions drawn from the DOE report.

2.7.4 PROJECT ALTERNATIVES DISMISSED FROM FURTHER CONSIDERATION BY PROJECT PROPONENTS

The following subsections discuss project alternatives and options for the connected actions that were initially identified and considered by the project proponents.

2.7.4.1 Alternative Size

Mississippi Power's IRP is the fundamental supply and demand planning process used to ensure that its customers continue to receive reliable service at the lowest practical cost through a mix of resources that meet current and future environmental requirements and that account for risk. The IRP projects a need of between 318 and 601 MW for baseload power by the summer peak season of 2014 (Mississippi Power, 2009a).

Table 2.7-1. Overview Comparison of IGCC and Other Coal-Based Technologies—EPA

	Lignite Coal				Sub-Bituminous Coal			
	IGCC Solid Feed Gasifier	Subcritical PC	Supercritical PC	Ultra Supercritical PC	IGCC Slurry Feed Gasifier	Subcritical PC	Supercritical PC	Ultra Supercritical PC
Performance								
Net thermal efficiency, % (HHV)	39.2	33.1	35.9	37.6	40.0	34.8	37.9	41.9
Net heat rate, Btu/kWh (HHV)	8,707	10,300	9,500	9,065	8,520	9,800	9,000	8,146
Gross power, MW	580	544	544	546	575	541	541	543
Internal power, MW	80	44	44	46	75	41	41	43
Fuel required, lb/hr	689,720	815,906	752,535	720,849	484,089	556,818	517045	460,227
Net power, MW	500	500	500	500	500	500	500	500
Environmental Impact lb/MWh								
NO_x (NO_2)	0.375	0.568	0.524	0.498	0.326	0.543	0.500	0.450
SO_2	0.150	0.814	0.751	0.714	0.089	0.589	0.541	0.488
CO	0.225	0.947	0.873	0.830	0.222	0.906	0.832	0.750
PM*	0.053	0.114	0.105	0.100	0.052	0.109	0.100	0.090
VOC	0.013	0.026	0.024	0.022	0.013	0.025	0.023	0.020
Solid waste‡	218	331	306	291	45	73	67	60
Raw water use	5,270	9,960	9,200	8,710	5,010	9,520	8,830	7,870
SO_2 removal basis, %	99	95.8§	95.8§	95.8§	97.5	87**	87**	87**
NO_x removal basis†	15 ppmvd @ 15% oxygen	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu	15 ppmvd @ 15% oxygen	0.06 lb/MMBtu	0.06 lb/MMBtu	0.06 lb/MMBtu
Costs††								
Total plant cost $/kW	$2,000	$1,255	$1,333	$1,432	$1,630	$1,223	$1,299	$1,395
Total plant investment $/kW	$2,260	$1,378	$1,463	$1,566	$1,840	$1,343	$1,426	$1,526
Total capital requirement $/kW	$2,350	$1,424	$1,511	$1,617	$1,910	$1,387	$1,473	$1,575
Annual operating cost, $1,000s	$34,000	$29,640	$30,940	$32,440	$29,700	$28,300	$29,600	$31,100

Note:
HHV = higher heating value.
Btu/kWh = British thermal unit per kilowatt-hour.
lb/MWh = pound per megawatt-hour.
NO_2 = nitrogen dioxide.
$/kW = dollars per kilowatt.
ppmvd = part per million by dry volume.
lb/MMBtu = pound per million British thermal units.

*Particulate removal is 99.9 percent or greater for the IGCC cases and 99.8 percent for bituminous coal, 99.7 percent for sub-bituminous, and 99.9 percent for lignite for the PC cases. The emission rates shown include the overall filterable PM only.

†A percent removal for NO_x cannot be calculated without a basis, i.e., an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NO_x emission comparisons are based on emission levels expressed in ppmvd at15-percent oxygen for IGCC and lb/MMBtu for PC cases.

‡Solid waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system.

§A relatively low SO_2 removal efficiency of 95.8 percent represents low lignite sulfur content of only 0.64 percent. Higher removal efficiencies are possible with increased coal sulfur content.

**A relatively low SO_2 removal efficiency of 87 percent represents low sub-bituminous coal sulfur content of only 0.22 percent. Higher removal efficiencies are possible with increased coal sulfur content.

††All costs are based on 4th quarter 2004 dollars.

Source: EPA, 2006.

Table 2.7-2. Overview Comparison of IGCC and Other Coal-Based Technologies—DOE

	Unit	IGCC*		Subcritical PC		Supercritical PC	
CO_2 capture		No	Yes	No	Yes	No	Yes
Gross power output	MW	754	711	583	680	580	663
Net power output	MW	633	530	550	550	550	546
Net efficiency	%	39.5	32.1	36.8	24.9	39.1	27.2
Net heat rate	Btu/kWh	8,636	10,645	9,276	13,724	8,721	12,534
Raw water usage	gpm	3,851	4,426	6,212	12,187	5,441	10,444
Total plant cost	million $	1,166	1,323	853	1,591	866	1,567
Total plant cost	$/kW	1,841	2,496	1,549	2,895	1,575	2,870
LCOE	mills/kWh^2	77.9	106.3	64.0	118.8	63.3	114.8
CO_2 emissions	10^3 tpy†	3,803	407	3,865	570	3,631	516
	lb/MMBtu	199	20.6	203	20.3	203	20.3
	lb/MWh‡	1,440	164	1,780	225	1,681	209
	lb/MWh§	1,714	202	1,886	278	1,773	254
SO_2 emissions	tpy†	228	189	1,613	Negligible	1,514	Negligible
	lb/MMBtu	0.012	0.0095	0.085	Negligible	0.085	Negligible
	lb/MWh‡	0.086	0.076	0.743	Negligible	0.701	Negligible
NO_x emissions	tpy†	1,101	947	1,331	1,966	1,250	1,784
	lb/MMBtu	0.057	0.049	0.07	0.07	0.07	0.07
	lb/MWh‡	0.417	0.385	0.613	0.777	0.579	0.722
PM emissions	tpy†	136	140	247	365	232	331
	lb/MMBtu	0.0071	0.0071	0.013	0.013	0.013	0.013
	lb/MWh‡	0.052	0.057	0.114	0.144	0.107	0.134
Lead emissions	lb/yr†	22	23	44	64	40	58
	lb/TBtu	0.571	0.571	1.14	1.14	1.14	1.14
	10^{-6} lb/MWh‡	4.14	4.54	10.0	12.7	9.45	11.8

Note: Btu/kWh = British thermal unit per kilowatt-hour.
$/kW = dollar per kilowatt.
mills/kWh = 0.1 cent per kilowatt-hour.
lb/MMBtu = pound per million British thermal units.
lb/MWh = pound per megawatt-hour.
lb/TBtu = pound per 10^{12} British thermal units.
10^{-6} lb/MWh = 0.000001 lb per megawatt-hour.

*Averages of three oxygen-blown IGCC systems.
†Capacity factors of 80 percent for IGCC, 85 percent for PC.
‡Based on gross output.
§Based on net output.

Sources: DOE, 2007a.
ECT, 2009.

The IRP process involves an evaluation of existing generating units, including the scheduled and potential retirement dates for those units, expected future customer and load growth, strategic considerations, demand-side management opportunities, and a preliminary screening of the various generating technologies available to meet any additional capacity requirements. The resulting needs, if any, are filled through an evaluation of both supply-side and demand-side options using marginal cost analysis. This approach ensures that both supply-side and demand-side options are included in the resource plans when it is economic to do so. When a need for a new supply-side resource is identified, the IRP process serves as the starting point for developing site-specific resource alternatives as part of the generation screening process.

When the IRP indicates a need for a new supply-side resource, the generic supply-side resource technologies identified in the IRP become the basis for the detailed screening and evaluation process used to determined the most cost-effective new supply-side option. In developing these plans, however, it is important to realize that, due to economies of scale, generating resources are typically built in economic capacity blocks that could result in a short-termed period of excess capacity.

After evaluating the resource need and considering the demand-side resource options and site-specific supply-side alternatives, the results of Mississippi Power's generation screening and resource selection process indicated that the Kemper County IGCC Project was the most economic generation resource alternative to meet the identified need in the 2014 timeframe.

2.7.4.2 Alternative Fuels

Because the design of the entire plant is highly dependent on the design fuel, the use of alternative coals (e.g., bituminous coal) is not possible for this proposed lignite project. In addition, the overall project premises the efficient and economical supply of lignite coal from the adjacent surface mine. The heating value of lignite is substantially lower than that of other coals. Thus, although plentiful, more lignite is necessary to release a given amount of energy, which makes transportation costs particularly high for lignite. Accordingly, transporting lignite from another location, even relatively short distances, is not economic for the long-term operation of the proposed plant. Thus, using coal from another location was not considered practical.

Additionally, the use of biomass feedstock is not considered feasible because of problems related to high-moisture content, relatively low-energy content, material handling issues, and material consistency issues. Although pilot-scale research using biomass feedstock with IGCC technology is ongoing within Southern Company, biomass is not planned for the proposed facilities due to the challenges and uncertainties associated with material preparation and with feeding biomass into pressurized systems. In addition, firing biomass would not meet the goals of the CCPI program. Other DOE programs are focused on developing alternative fuel technologies.

2.7.4.3 Alternative Plant Layout

Steps to establishing the IGCC plant site arrangement included a review of available space for the facility at a macro level. As part of site selection, the site area was overlaid with a rectangular area of 60 to 80 acres, representing the minimum space sufficient for the combined gasifier system and power block. Several locations on the site were preliminarily determined to be of sufficient size and at an elevation above the 100-year floodplain and with comparable amounts of site improvements required. With each of the locations considered for the footprint, companion areas in excess of 100 acres were also identified for potential placement of ash storage. With several potential configurations initially possible, the site as proposed was deemed to have sufficient space and flexibility to allow continued development through continued engineering design and layout studies.

The proposed IGCC plant layout would have a similar set of engineering constraints and design requirements as other simple-cycle and combined-cycle plants that Southern Company has designed and constructed (SCS, 2009). Ideally:

- The CT machine axes are aligned parallel to each other and with the steam turbine axis.
- All of the generator step-ups for the combined-cycle block are in a line that is perpendicular to the generator axis.
- The HRSGs are on the opposite side of a CT from the generator, but on the same axis.
- The cooling towers associated with the HRSGs are reasonably close and aligned to the steam turbine. The cooling towers should be in an advantageous direction (downwind) and at a sufficient dis-

tance to minimize drift to the power block. One cooling tower is required per combined-cycle block. Cooling towers must also be at a minimum of 1,000 ft from roads or highways.

- Condensate storage tanks, a water plant, and administration/control building are located adjacent to the unit.
- Adequate buffer area is provided between surrounding properties and the power block and associated equipment. As with the simple-cycle and combined-cycle layouts, the buffer area for an IGCC facility will vary depending on local surroundings. Minimizing offsite noise is an important factor in providing buffer.

The proposed gasification component would also require its own 10-cell cooling tower that would also have to be located a minimum of 1,000 ft from roads or highways. The proposed IGCC plant also would need to include coal handling facilities and provisions for ash storage onsite, as discussed elsewhere. NACC's coal handling facilities, including settling ponds, would also need to fit within the 1,650-acre site. Another constraint on this site is the presence of low areas, including wetlands associated with Chickasawhay Creek, covering much of the western area of the site.

As discussed in Subsection 2.5.3, the onsite facilities would include an approximately **90**-acre pond or reservoir to store reclaimed effluent received by pipeline from the Meridian POTWs. The **initially preferred** reservoir location **east of MS 493** was chosen based on space availability, topography, and possible future expansion considerations. The existing topography on the eastern side of the proposed plant property contains a natural valley-shaped area. This area, when dammed from one end, would form a natural reservoir or pond area. The advantageous topography would lend itself to a cost-effective means of storing a large quantity (approximately 500 million gallons) of water. **However, this area was subsequently determined to affect a larger total of linear stream feet, so a less preferable area from a technical standpoint south of the power plant footprint was identified.**

Building and operating a series of tanks in an upland area with the capacity to provide adequate water supply storage would be prohibitively expensive. Excavation of upland areas to create the reservoir would be less expensive than tanks, but still prohibitively expensive and thus not feasible. In addition, because of the limited upland space available within the plant property, both of these water storage methods would interfere with possible future expansion considerations.

The proposed layout incorporating all of these facilities was shown in Figure 2.1-**6**. As this layout showed, meeting the basic design constraints would limit the possible options for placing equipment and facilities on the site. The proposed layout would meet the principal criteria (discussed previously), provide space for water and waste storage (if needed), **while also avoiding the streams on the eastern side** of the site.

2.7.4.4 Alternative Mining Methods

Alternative methods for lignite extraction have been excluded from further consideration because no discernable difference in impacts would result from practicable surface mining methods. Underground mining would result in reduced impacts at the land surface. However, underground mining would only be practicable where the mineral reserve was deep below the land surface and within consolidated lithology. As described in Section 3.4, the lignite reserves in Kemper County are shallow and lie beneath unconsolidated strata of sands and clays. Underground mining is not technically feasible at this location.

2.7.4.5 Alternative Mine Development Plans

During the preparation of this EIS and as a result of preapplication consultations with USACE, NACC responded to DOE and USACE comments and input by revising the mine development plan, the proposed configuration for which was shown in Figure 2.2-4. The following subsections describe the alternatives that were considered.

Alternative Mine Plan "A"

Alternative mine plan "A" would recover the most lignite by maximizing the recovery of the lignite resource and maximizing the economy of the mining technique. This mine plan was based primarily on lignite characteristics and associated recovery economics. The most economically viable lignite reserves were identified, a 40-year mine plan was developed, and water control structures, including sediment ponds, diversions, and levees, were designed (see Figure 2.7-2).

This plan would establish a water containment and diversion system that would capture inflowing fresh water in a large pond on the north end (R-1) and divert the water around the west of the mine disturbance area through a series of ponds and diversions. The discharge would then flow into the Okatibbee Creek at the west end of the mine block labeled YR21 to YR25 and would then flow through the WMA into Lake Okatibbee.

A large sediment pond (SP-1) would be designed immediately south of the mine blocks, in the WMA, to capture the water runoff from the mine disturbance area. This pond would discharge directly into Lake Okatibbee. In addition, surface water coming onto the project area, north of the plant site, would be diverted southeast of the plant site to the Tombigbee watershed.

Once water was diverted, mining would initiate in the middle of the project area and would advance to the south with pits that extend almost the entire width of the mine blocks. In addition, prior to year 21 of mining, Okatibbee Creek would be diverted south of its current location to accommodate mining in and through that area. Alternative mine plan "A" would maximize the footprint of the mine impacts and represent a large wetland disturbance due, in part, to the disturbance of Okatibbee Creek and the WMA.

Lignite extraction by implementing alternative mine plan "A" would remove up to 53 miles of stream channels and impact up to 2,153 acres of wetlands, exclusive of the impacts generated by construction of the permanent mine facilities. Construction of the reservoirs and sedimentation ponds would impact up to 52 miles of streams and 1,355 acres of wetlands.

Alternative Mine Plan "B"

A subsequent mine plan (Figure 2.7-3) was developed to account for hydrologic impacts to the WMA and Okatibbee Creek. This mine plan would be similar to the previously discussed Plan "A," but under this alternative the southwestern mine block, labeled YR21 to YR25, would be shifted north to avoid disturbance to Okatibbee Creek and the associated riparian wetlands. Consequently, disturbance to the WMA and associated wetlands would be avoided by reducing the size of SP-1 and moving the pond north of the WMA, immediately south of the mine blocks. The benefit of this alternative would be in the reduction of the impact to Okatibbee Creek and the

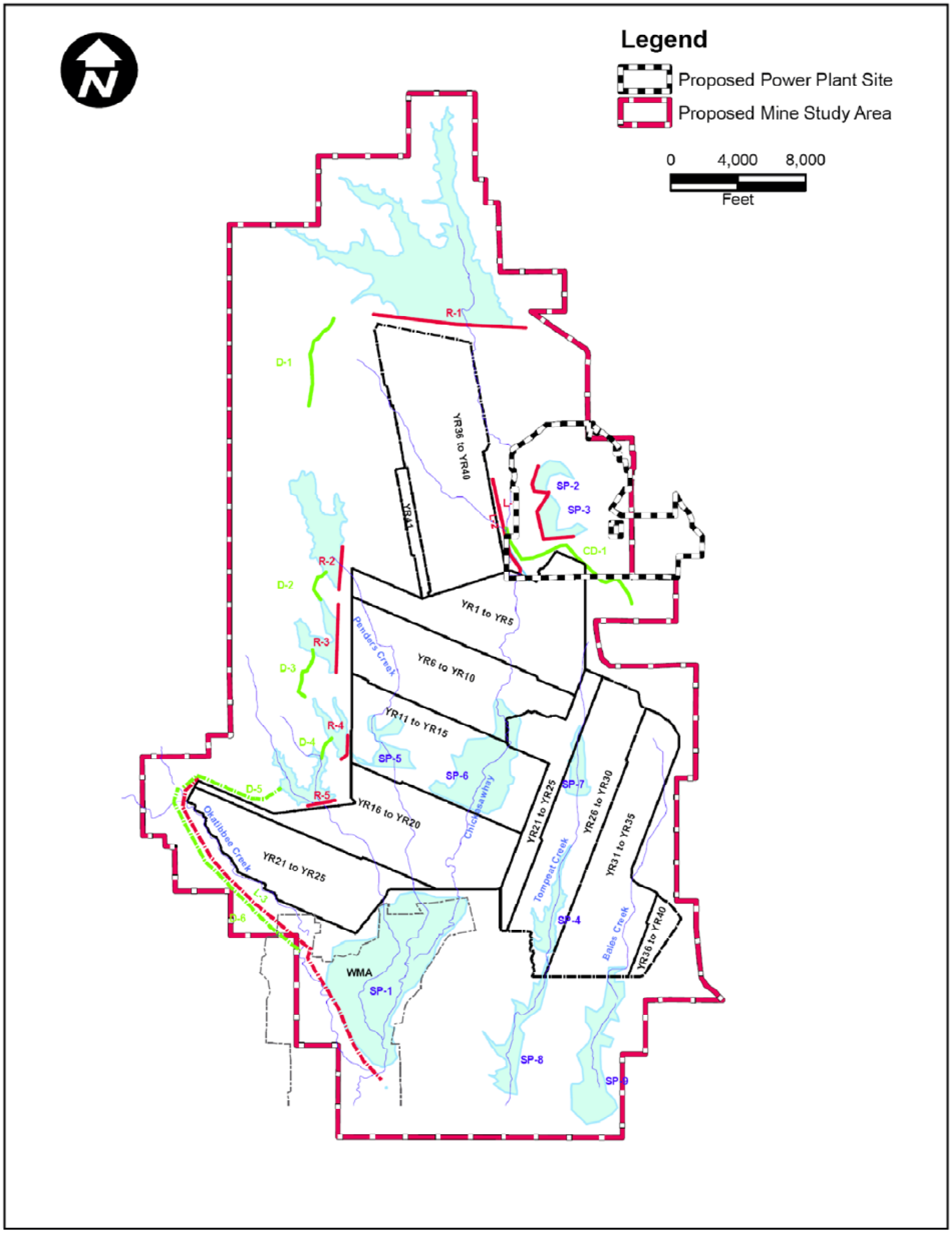

Figure 2.7-2. Alternative Mine Plan "A"
Source: NACC, 2009.

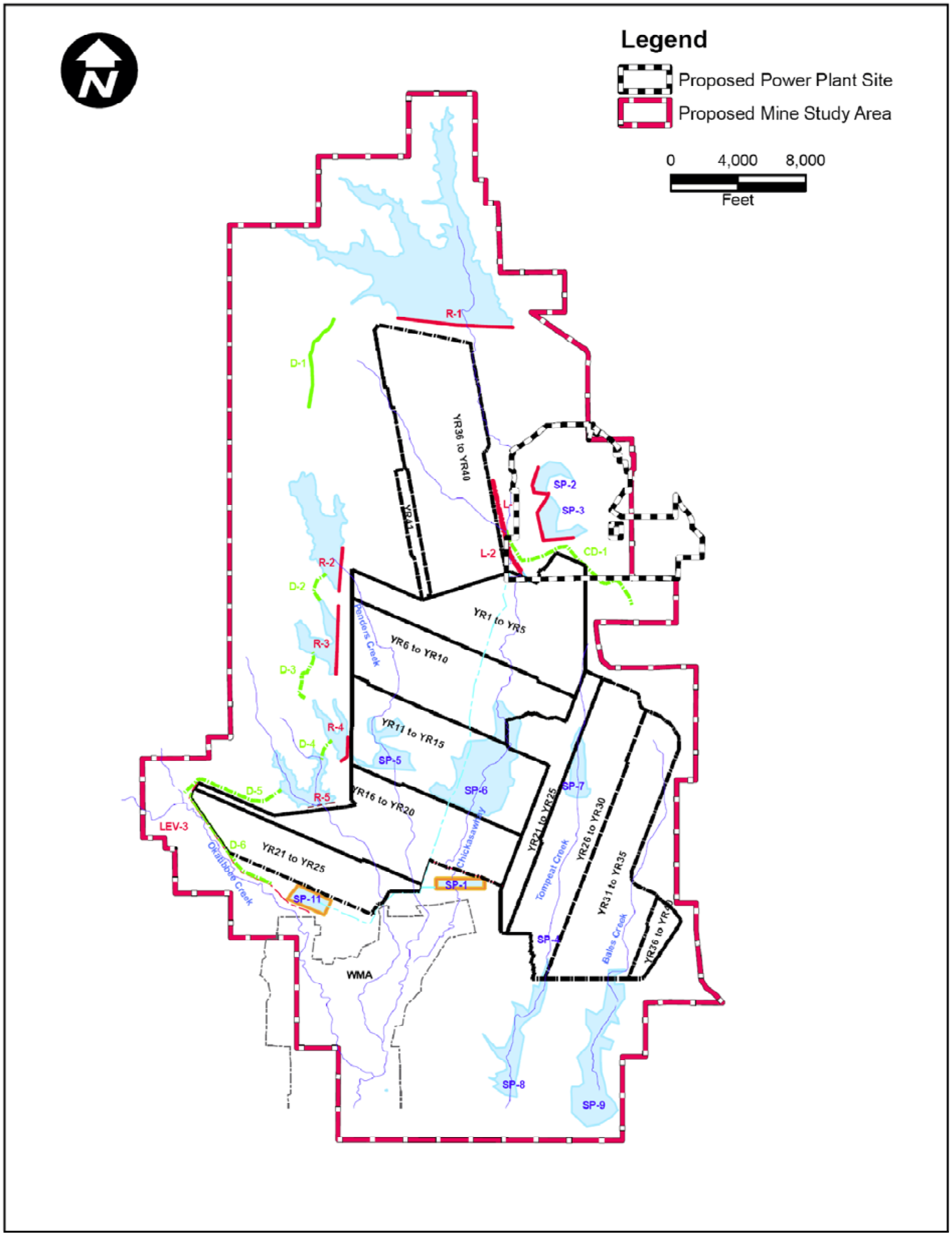

Figure 2.7-3. Alternative Mine Plan "B"

Source: NACC, 2009.

WMA. This plan would still contemplate the full east-west pit extension that extends the temporal disturbance to Chickasawhay Creek.

Implementation of alternative mine plan "B" would result in removal of up to 51 miles of stream channels and impact up to 1,889 acres of wetlands due to lignite extraction, exclusive of the impacts generated by construction of the permanent mine facilities. Construction of the reservoirs and sedimentation ponds would impact up to 54 miles of streams and 594 acres of wetlands.

Alternative Mine Plan "C"

A third alternative (Figure 2.7-4) was developed to further protect the overall project-area hydrologic balance while still maximizing economic lignite recovery. The reservoir on the north end of the project area (R-1) would be eliminated, and the fresh water drainage would be controlled through a series of ponds on the west side of the mine blocks. This clean water would drain to Lake Okatibbee via Okatibbee Creek. The mine blocks would be reoriented from the previous full east-west extension to three east-west panels to minimize impacts to the individual watersheds. Because of the three panels, Chickasawhay Creek would be diverted in a step-wise manner, thus minimizing the duration of impact in any given area. Additionally, water inflow on the northeast side of the project area would be managed in a series of diversions and levees, thereby retaining all surface water within the Chickasawhay drainage basin. This alternative would allow for mining of economically viable lignite reserves in the southwest corner of the mine study area. The lignite in this area is high quality and has a low recovery ratio. Because of the low recovery ratio of overburden to lignite, less overburden would be disturbed for a comparable volume of lignite.

Alternative mine plan "C" lignite extraction would remove up to 48 miles of stream channels and impact up to 1,892 acres of wetlands, exclusive of the impacts generated by construction of the permanent mine facilities. Construction of the reservoirs and sedimentation ponds would impact up to 46 miles of stream channel and 217 acres of wetlands.

Alternative Mine Plan "D"

This alternative, which is the proposed mine plan discussed in Subsection 2.2.1 and shown in Figure 2.2-4, was designed to be more protective of the project area hydrologic balance. However, this alternative would preclude the recovery of a substantial volume of economically viable reserves as a result of avoiding portions of the Penders Creek basin and the area immediately northeast of Okatibbee Creek.

The large sediment pond north of the project area and the series of ponds on the west side of the mine blocks included in all prior alternatives would be eliminated. Inflows from the north would flow to Lake Okatibbee though a series of clean water diversions and levees and would no longer be diverted around the west side of the reserve blocks. Therefore, this plan would no longer divert water into the section of the Okatibbee Creek by mine blocks YR21 to YR25. It would also eliminate the need for the large pond on the south side of the mine blocks in the WMA. In addition, it would change the sequence of mining on the west side of the mine blocks by not mining the reserves on the west side of the main channel of Pender's Creek (in block D) to minimize the impact to the streams and to offset from Okatibbee Creek to avoid a large portion of the wetlands associated with Okatibbee Creek.

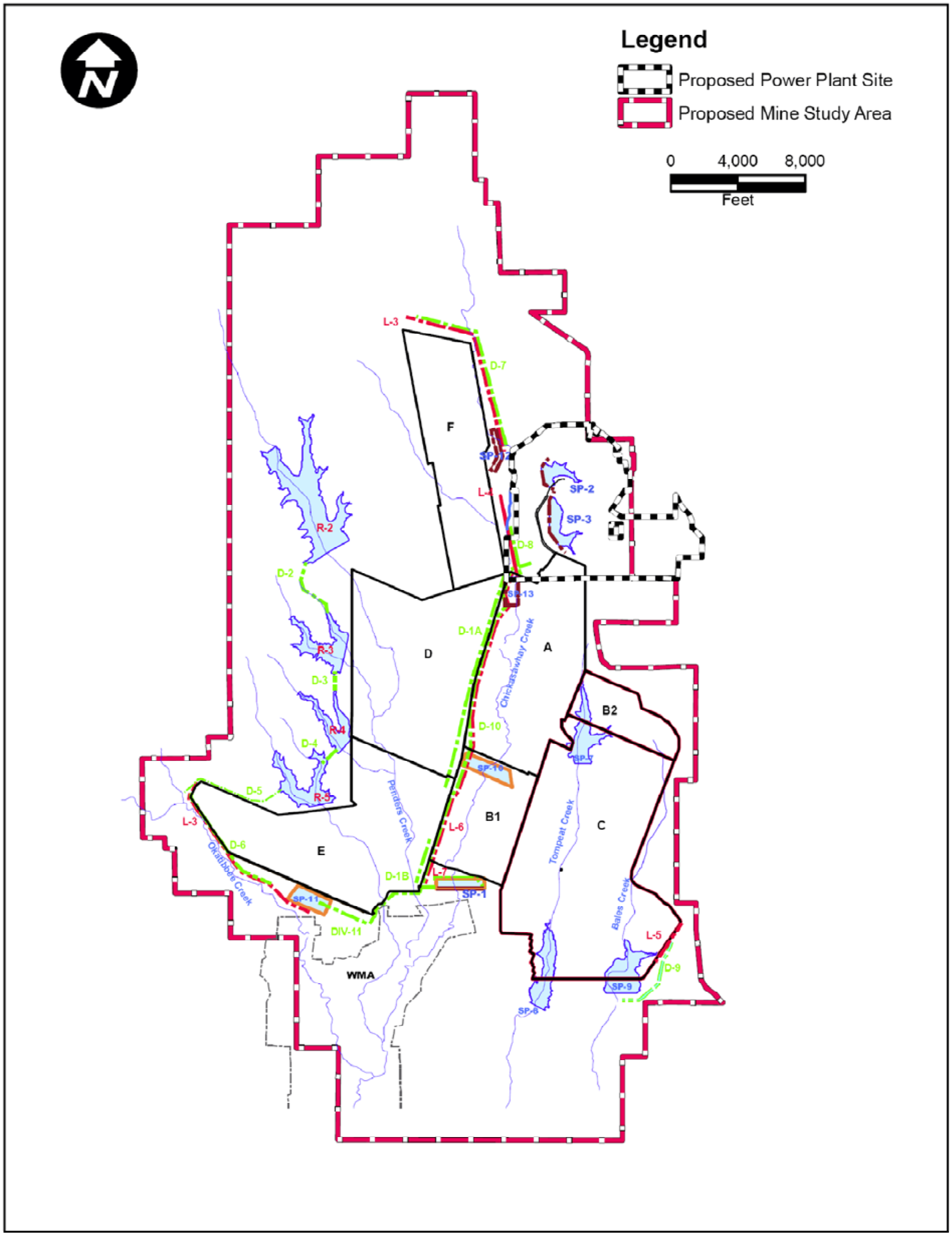

Figure 2.7-4. Alternative Mine Plan "C"

Source: NACC, 2009.

This alternative would minimize wetland and floodplain impacts compared to the other alternative mine plans. However, approximately 10.0 million tons of lignite would remain in the ground. Long-term operational costs would increase as a result of having to mine lignite from higher ratio (overburden to lignite) reserves with less favorable recovery economics.

Implementation of alternative mine plan "D" would remove of up to 56 miles of stream channels, including channels located in lignite extraction areas, sedimentation ponds, and permanent facilities. The total wetland impact would be up to 2,491 acres. On the basis of reduced stream and wetland impacts, alternative mine plan "D" was selected by NACC as its proposed action.

2.7.4.6 Alternative Means of CO_2 Sequestration

The Kemper County IGCC Project would intend to capture approximately 67 percent of the carbon from the produced syngas as CO_2. The recovered CO_2 would then be compressed to the required pressure and exit the gasification facility in a pipeline. The CO_2 would be transported via pipeline to an existing oil field for beneficial use in EOR and geologic storage.

To investigate practical options for managing the captured CO_2, Mississippi Power commissioned a study to characterize the carbon storage and sequestration opportunities for the captured CO_2 from the proposed IGCC plant (Pashin *et al.*, 2008). In this study, an evaluation of the deep subsurface geology was performed, which included the compilation and interpretation of a large volume of geophysical, stratigraphic, and structural information from wells and seismic profiles. Geologic sequestration opportunities were characterized by defining the fresh-water aquifers that need to be protected, delineating confining strata, and analyzing saline reservoirs that can safely store a large volume of CO_2 over geological time.

Geologically, Kemper County lies at a crossroads of North American geology where the juncture between the Appalachian and Ouachita orogenic belts is on-lapped by poorly consolidated Mesozoic strata of the Gulf of Mexico Basin (Thomas, 1985; Hale-Erlich and Coleman, 1993). The geology is diverse and contains basic geologic formations in proximity to the proposed IGCC plant that are potentially favorable for geologic sequestration. However, the potential and quality of these formations cannot be determined sufficiently. Significant field efforts at the site would need to be performed before a geologic framework could be developed. This effort would include reservoir modeling, the drilling and logging of an exploratory test well, and seismic analysis.

Equally important, in contrast to EOR, which is an accepted and demonstrated commercial technology, commercial-scale geologic sequestration must overcome significant legal, commercial and regulatory barriers beyond validating sequestration geology including: (1) property rights (pore ownership and issues of trespass), (2) a unified regulatory framework for large-scale underground injection and geologic storage, and (3) long-term liability issues related to the maintenance and monitoring of closed sites (SCS, 2009).

This page intentionally left blank.