2 PROPOSED ACTION AND ALTERNATIVES

2.1 INTRODUCTION

This chapter describes DOE's Proposed Action and the alternatives considered. DOE's Proposed Action and No Action Alternative are described in Section 2.2, along with a discussion of the other alternatives that DOE considered. Section 2.3 describes AEP's proposed Mountaineer CCS II Project and includes detailed descriptions of the following proposed project components:

- CO_2 capture facility
- CO_2 pipelines and corridors
- CO_2 injection and monitoring well locations
- Resources required
- Construction and operation plans
- CO_2 monitoring, verification, and accounting (MVA) activities
- Measures to reduce potential impacts

Section 2.4 presents project implementation options being considered by AEP and the manner in which these options are analyzed within this EIS.

2.2 PROPOSED AGENCY ACTION AND ALTERNATIVES CONSIDERED

2.2.1 DOE Proposed Action

> DOE's Proposed Action includes a 46-month **demonstration period** that would validate an advanced coal-based technology that captures and sequesters CO_2 emissions from a coal-fired power plant.

DOE proposes to provide cost-shared financial assistance to AEP for the planning, design, construction, and operation of the proposed project. DOE's Proposed Action is to provide AEP with up to $334 million of the $668 million (in "as-spent," or actual dollars) estimated project cost. The financial assistance provided by DOE would constitute about 50 percent of the estimated total project cost. The project would help DOE meet a specific objective of Round 3 of the CCPI Program by demonstrating an advanced coal-based technology that captures and sequesters, or puts to beneficial use, CO_2 emissions from a coal-fired power plant (see Section 1.2). The proposed project is described in detail in Section 2.3.

2.2.2 Alternatives Considered by DOE

Section 102 of NEPA requires that agencies discuss the reasonable alternatives to the Proposed Action in an EIS. The term "reasonable alternatives" is not self defining, but rather must be determined in the context of the statutory purpose expressed by the underlying legislation. The purpose and need for a federal action determines the reasonable alternatives for the NEPA process.

Any reasonable alternative to the Proposed Action must be capable of satisfying the purpose and need of the CCPI Program. As described in Section 1.2 of this EIS, Congress established the CCPI Program with a specific goal—to accelerate the commercial deployment of advanced coal-based technologies that can generate clean, reliable, and affordable electricity in the U.S. The narrow focus of the CCPI legislation directs DOE to demonstrate coal-based technology advancements, thereby reducing the barriers to continued and expanded use of coal to generate electricity.

Alternatives considered by DOE originate as private-party (e.g., electric power industry) applications submitted to DOE in response to requirements specified in CCPI solicitations. DOE is limited to considering the application as proposed by the applicant. For example, DOE cannot consider site or technology combinations other than those included in the applications received. The applicant provides at least a 50-50 cost share and bears the primary responsibility for designing and executing the project. DOE's primary action concerning these applications is to decide which projects would receive DOE financial assistance from among the eligible applications submitted. Unlike a project initiated and operated by DOE, DOE 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 DOE by the applicant; DOE cannot design its own project and compel a private entity to implement it.

DOE's decision is to either accept or reject the project as proposed by the proponent, including its proposed technology and selected sites. However, DOE may specify mitigation measures that would be required as part of the proposed action. DOE's proposed action is limited to providing financial assistance in cost-sharing arrangements to projects that were submitted by applicants in response to a competitive funding opportunity. Consequently, DOE's consideration of reasonable alternatives is also limited to the technically acceptable applications and the No Action Alternative for each selected project.

2.2.2.1 No Action Alternative

Under the No Action Alternative, DOE would not provide cost-shared funding for the proposed Mountaineer CCS II Project. In this case, the funding withheld from the Mountaineer CCS II Project may be made available for other current or future CCPI projects. In the absence of DOE cost-shared funding, AEP could still elect to construct and operate the proposed project; therefore, the DOE No Action Alternative could result in one of two potential scenarios:

- The proposed Mountaineer CCS II Project would not be built.
- The proposed Mountaineer CCS II Project would be built by AEP without benefit of DOE cost-shared funding.

DOE assumes that if AEP proceeded with project development in the absence of DOE cost-shared funding, the project would include the features, attributes, and impacts as described for the Proposed Action. However, without DOE participation, it is possible that the project would be canceled. Therefore, for the purposes of analysis in this EIS, the DOE No Action Alternative is defined as the No-Build Alternative. This means that the project would not be built and environmental conditions would not change from the current baseline (i.e., no new construction, resource utilization, or CO_2 capture and storage would occur).

Therefore, under the No Action Alternative, the project technologies (i.e., large-scale CO_2 capture and geologic storage) may not be implemented in the near term. Consequently, timely commercialization of these technologies for large-scale, coal-fired electric generation facilities would be postponed and may not be realized. This scenario would not contribute to the CCPI goals to invest in the demonstration of advanced coal-based power generation technologies that capture and sequester, or put to beneficial use, CO_2 emissions. While the No Action Alternative would not satisfy the purpose of or need for the Proposed Action, this alternative was retained to provide a comparative baseline against which to analyze the effects of the Proposed Action, as required under CEQ Regulations (40 CFR 15012.14). The No Action Alternative reflects the current baseline condition and serves as a benchmark against which the effects of the Proposed Action can be evaluated.

2.2.2.2 Alternative Project Applications Considered During the CCPI Procurement Process

DOE's alternatives to its Proposed Action for CCPI - Round 3 consist of the other technically acceptable applications received in response to FOA DE-FOA-0000042, *Clean Coal Power Initiative - Round 3, Amendments 005 and 006*. DOE received 36 applications that met the minimum eligibility requirements listed in the FOA under Round 3 of the CCPI. These applications provided DOE with a range of options for meeting the objectives of Round 3 of the CCPI. DOE screened each of these 36 applications to evaluate potential environmental consequences of each application during DOE's initial review and made preliminary determinations regarding the level of NEPA review required. DOE documented the potential environmental consequences for each application in an environmental critique and summarized the results in a publicly available environmental synopsis (see Appendix A). DOE prepared this synopsis in accordance with DOE's NEPA implementing regulations, as found in 10 CFR 1021.216(h). Through this review process, DOE considered both potential environmental consequences and the ability of each application to meet the purpose of and need for action. DOE uses the procedures established in its NEPA regulations, specifically those in 10 CFR 1021.216, to identify and consider the potential environmental impacts of the eligible projects in making its selections as described in Section 1.5.1. The preliminary NEPA determinations and environmental reviews were provided to the selecting official for consideration during the selection process.

Ultimately, DOE determined that the proposed Mountaineer CCS II Project and four other applications would best meet the goals and objectives of the CCPI Program. The proposed projects from these five applications must each complete a separate, independent, project-specific (and more detailed) NEPA analysis that would each be expected to result in separate RODs. Although these five projects are eligible for cost-shared funding under CCPI, there is no other relationship among them. The selection and potential execution of each stand-alone project has no effect or bearing on the other projects.

2.2.3 Project Options Considered by the Project Proponent

AEP responded to the DOE's solicitation with its application for the proposed project, which is based on a commercial scale-up of the existing CAP product validation facility (PVF), constructed at the Mountaineer Plant in 2009. The PVF captures CO_2 from a 20-MW flue gas slipstream and injects the captured CO_2 into two deep geologic formations via two wells located on the Mountaineer Plant property. The PVF is providing AEP with the opportunity to evaluate Alstom's CAP for CO_2 capture. The PVF project is successfully integrating Alstom's CAP technology with a compression system, and geologic storage system. To date, the CAP has met removal efficiency goals while producing a high quality CO_2 stream suitable for underground injection and storage. The geologic storage system receives the injected CO_2 while operating within the Class V Underground Injection Control permit conditions. Overall, the PVF is meeting its goals in validating the CO_2 capture and storage system and is serving as the design basis for the proposed project. AEP's proposed project is designed to demonstrate the commercial-scale operation of an integrated CCS project using Alstom's CAP process. The proposed project uses a similar process, albeit larger in size, to the PVF.

AEP initially identified 10 AEP-owned properties as candidates for CO_2 injection wells. AEP determined the five closest properties to be the most feasible, which would also minimize potential environmental impacts. AEP eliminated the remaining properties from further consideration as these properties were located much further from the Mountaineer Plant and presented significant challenges in securing ROW agreements and regulatory approvals in a timely manner. Likewise, the greater distance would add significant cost and time to the overall project, as well as create a greater potential for environmental impacts associated with additional stream, river, and wetland crossings.

2.2.4 Preliminary Project Option

Because Alstom's CAP technology may result in lower energy losses compared to other methods of post-combustion CO_2 capture, AEP did not consider other CO_2 capture technologies as part of their proposed project. However, AEP plans to complete a study to evaluate the feasibility of an amine-based CO_2 capture technology. AEP entered into a cooperative agreement with China Huaneng, through which AEP, China Huaneng, DOE, and the National Energy Administration of China will perform an initial evaluation of a post-combustion, advanced amine-based CO_2 capture technology. AEP will complete a study to evaluate the feasibility of the technology for potential use at supercritical coal-fired generating units with characteristics similar to the Mountaineer Plant. The feasibility study would evaluate technical issues related to design, performance, cost, and process integration. In addition, it would consider lessons learned from the testing and deployment of this technology by others for possible application to the Mountaineer CCS II Project. Results of the study may provide insight on key design and operating considerations, which could be used to evaluate development opportunities and associated risks in context with other potential CO_2 capture processes. In the event that AEP elects to move beyond the initial feasibility study and consider this as an alternative technology for this project, additional NEPA analysis could be needed to evaluate whether the potential impacts of this technology are significantly different from those of Alstom's technology.

2.2.5 Interim Actions

Interim actions, as defined by DOE's NEPA implementing regulations at 10 CFR 1021.104, are actions that are the subject of an ongoing EIS that DOE proposes to take before the ROD is issued and that are permissible under 40 CFR 1506.1 (Limitations on actions during the NEPA process). For an action to be considered permissible under 40 CFR 1506.1, it must not (1) have an adverse environmental impact; or (2) limit the choice of reasonable alternatives. DOE identified the action of providing financial support to AEP for the installation of a geologic characterization well at the Borrow Area as an allowable interim action. DOE determined that the well at this location would not have adverse environmental impacts or limit the choice of reasonable alternatives in accordance with 40 CFR 1506.1. During the course of this effort, if DOE learns of significant new information regarding its potential impacts (e.g., discovers endangered species or artifacts at the site), DOE would reconsider whether to proceed with the effort as an interim action. The data and information obtained from this well and other ongoing characterization activities will be used to refine project strategy.

2.3 DESCRIPTION OF APPLICANT'S PROPOSED PROJECT

2.3.1 Introduction

AEP's proposed project includes the design, construction, and operation of a commercial-scale CO_2 capture and geologic storage facility. The project would demonstrate the operation of an integrated CCS process at commercial scale on a coal-fired power plant. There are four primary components of the project:

1. **CO_2 Capture Facility** – The facility would capture CO_2 from a 235-MW flue gas slipstream from the existing 1,300-MW Mountaineer Plant. The facility would be designed with a target CO_2 capture rate of 90 percent and built on plant property.
2. **CO_2 Pipelines** – The captured CO_2 would be transported by pipeline (primarily underground) to AEP-owned properties located within 12 miles of the Mountaineer Plant.
3. **CO_2 Injection Wells** – The captured CO_2 would be injected into geologic saline formations located approximately 1.5 miles below the ground surface through injection wells located on two or more AEP-owned properties.
4. **CO_2 Storage Monitoring** – A geologic monitoring program would be established and operated in accordance with the required Underground Injection Control (UIC) permit.

Figure 2-1 presents an overall schematic of the existing PVF storage system, which includes features similar to the proposed project, albeit on a smaller scale. Each of these four project features is summarized in Table 2-1. Figure 2-2 shows the general location of the proposed project components.

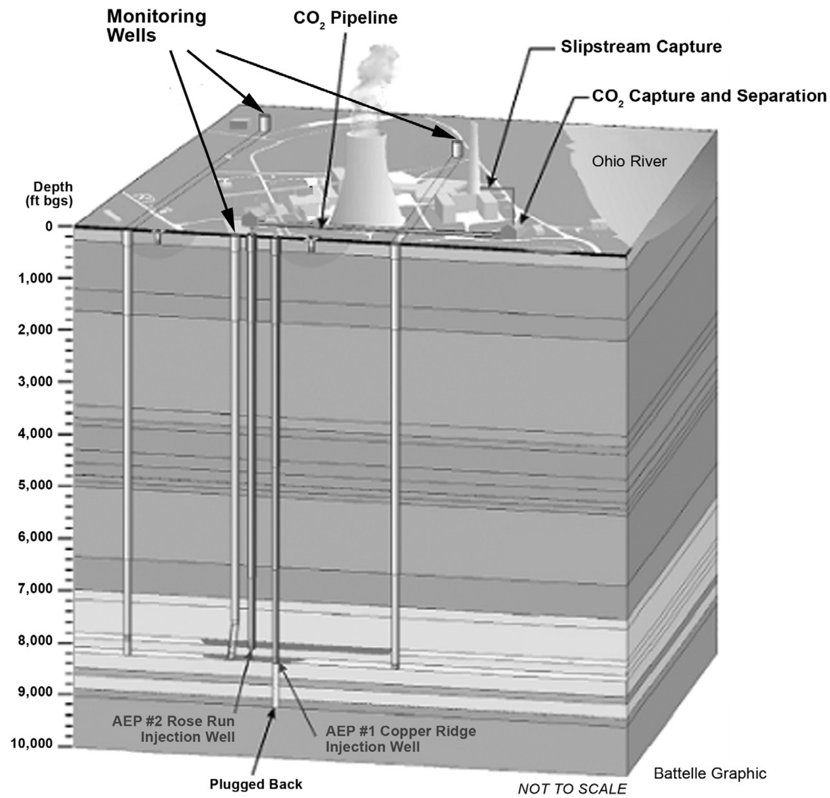

Figure 2-1. Schematic for Existing PVF System

The preferred locations of proposed project features, including access roads, pipelines, and injection well sites, are further addressed in this section. AEP developed and applied siting criteria to initially site project features. AEP would use these same siting criteria when selecting the monitoring well locations and in the event that a project feature would need to be relocated. These siting criteria include the following (to the extent practicable):

- **Avoid wetlands** – Project features would avoid wetland areas.
- **Avoid streams and floodplains** – Project features would avoid streams and floodplains and minimize the number of pipeline stream crossings.
- **Avoid sensitive habitats** – Project features would avoid areas identified as sensitive habitats.
- **Avoid cultural resources** – Project features would avoid areas containing known cultural resources.
- **Proximity to public roads** – Project features would use areas with ready access to public roads to minimize the creation of new access roads.
- **Topography** – Project features would use areas that are generally flat to minimize grading requirements and erosion potential.

Table 2-1. Proposed Mountaineer CCS II Project Features

Proposed Project Feature	Description	Characteristics
CO_2 Capture Facility	**Location:** A capture facility would be constructed at AEP's Mountaineer Plant. The facility would use the Alstom CAP to capture CO_2 from a 235-MW flue gas slipstream from the plant's 1,300-MW pulverized coal-fired electric generating unit.	**Facility Footprint:** 500 x 1000 feet (11.5 acres), located within a 33-acre area at the Mountaineer Plant.
CO_2 Pipelines	**Route:** Pipelines used to transport CO_2 from the Mountaineer Plant to the injection wells would be co-located within existing road and HVTL ROWs, to the extent possible. The length of the pipeline routes vary by corridor option as shown in Table 2-9. The range of pipeline lengths to the following injection well properties is: (1) Mountaineer Plant (0.13 mile) (2) Borrow Area (2.24 miles) (3) Eastern Sporn Tract (5.00 to 8.65 miles) (4) Jordan Tract (9.24 to 9.68 miles) (5) Western Sporn Tract (5.69 miles) **Operator:** AEP would own, operate, and maintain the CO_2 pipeline.	**Construction ROW Width:** 80-120 feet[a] **Permanent ROW Width:** 50 feet
CO_2 Injection Well Properties	**Location:** AEP anticipates that the project would require four to eight wells, located in pairs, at two to four of the following five properties: (1) Mountaineer Plant (33 acres) (2) Borrow Area (28 acres) (3) Eastern Sporn Tract (400 acres) (4) Jordan Tract (195 acres) (5) Western Sporn Tract (70 acres) **Quantity:** Each well would be designed to inject approximately 0.5 million metric tons of CO_2 per year. The total injection rate would be 1.5 million metric tpy.	**Construction Area:** Approximately 5 acres per injection well site **Well Depth:** Approximately 1.5 miles (7,920 feet) bgs **Operational Area:** 0.5 acre per site
Monitoring Wells	**Location:** The final approved UIC permit would dictate the final number of, and siting requirements for monitoring wells. Characterization wells could be converted into monitoring wells in the future. For this analysis, it is estimated that AEP would construct and use one to three monitoring wells per injection well, and that the monitoring wells would be placed within approximately 1,500 to 3,000 feet of the injection wells.	**Construction Area:** Approximately 5 acres per well site **Well Depth:** Dependent upon UIC permit requirements **Operational Area:** 0.5 acre per site (may be co-located at injection well sites)
Access Roads	**Location:** Access roads would be constructed from public roads to injection well sites.	**Construction Width:** 25 - 30 feet[a] **Permanent Width:** 12 - 15 feet

[a] The construction ROW at locations with steep side slopes may exceed 120 feet by up to 20 percent (i.e., up to 144 feet).

bgs = below ground surface; CAP = chilled ammonia process; CO_2 = carbon dioxide; HVTL = high voltage transmission line; MW = megawatt; tpy = tons per year; UIC = Underground Injection Control;

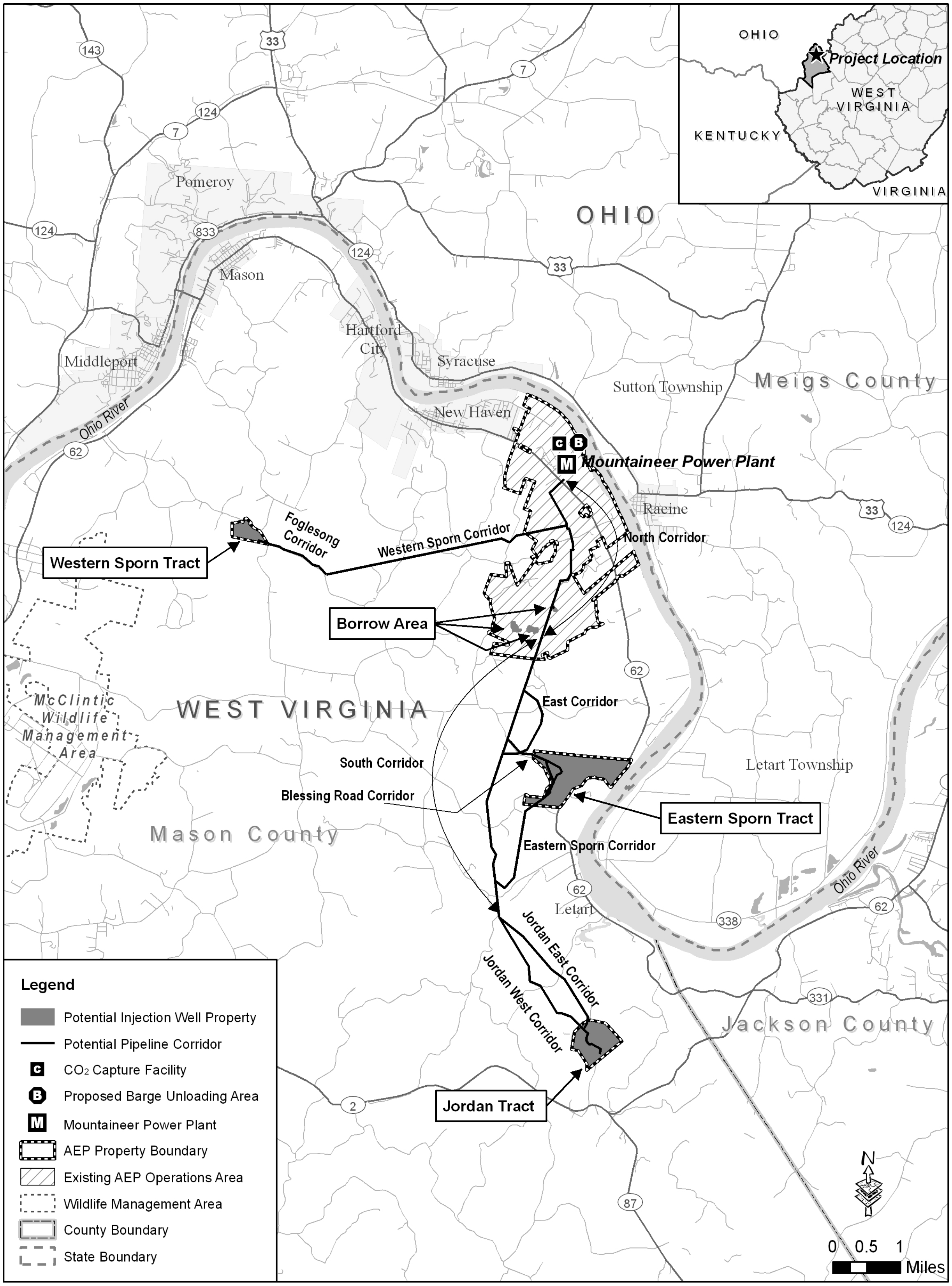

Figure 2-2. General Area Map

2.3.2 Organization of this Section

The following sections describe AEP's proposed Mountaineer CCS II Project and include detailed descriptions of the proposed project components:

- CO_2 capture facility (Section 2.3.3)
- CO_2 pipelines (Section 2.3.4)
- CO_2 injection wells (Section 2.3.5)
- CO_2 storage monitoring (Section 2.3.6)
- Decommissioning (Section 2.3.7)
- Measures to reduce potential impacts (Section 2.3.8)

2.3.3 CO_2 Capture Facility

The proposed project would install a CO_2 capture facility at AEP's existing Mountaineer Plant (see Figures 2-2 through 2-5). The facility would use Alstom's CAP technology to capture approximately 1.5 million metric tons of CO_2 annually based on a design target of 90 percent CO_2 reduction from a 235-MW flue gas slipstream of the 1,300-MW Mountaineer Power Plant. The captured CO_2 would be transported by pipeline to injection wells located up to approximately 12 miles from the plant.

2.3.3.1 Location and Background

The Mountaineer Plant, shown in Figures 2-2 and 2-3, is located on a 450-acre property in Mason County, West Virginia. Other AEP facilities located on the property include the Phillip Sporn Power Plant and the Little Broad Run Landfill, both of which are owned and operated by AEP. The portion of the property where the Mountaineer Plant is located is bounded to the west by State Route 62, to the east by the Ohio River, and to the south by AEP's Phillip Sporn Power Plant. Figure 2-2 shows the location of the Mountaineer Plant and the AEP property boundary. The town of New Haven, West Virginia, is located approximately 1 mile to the northwest (i.e., down-river). The plant occupies an industrial area located next to relatively undeveloped lands, with scattered residences and mining operations to the south and west. The CAP facility would have a footprint of approximately 500 feet by 1,000 feet (11.5 acres), located within a 33-acre area at the existing Mountaineer Plant (see Figure 2-5).

Figure 2-3. Mountaineer Plant

Figure 2-4. Mountaineer PVF

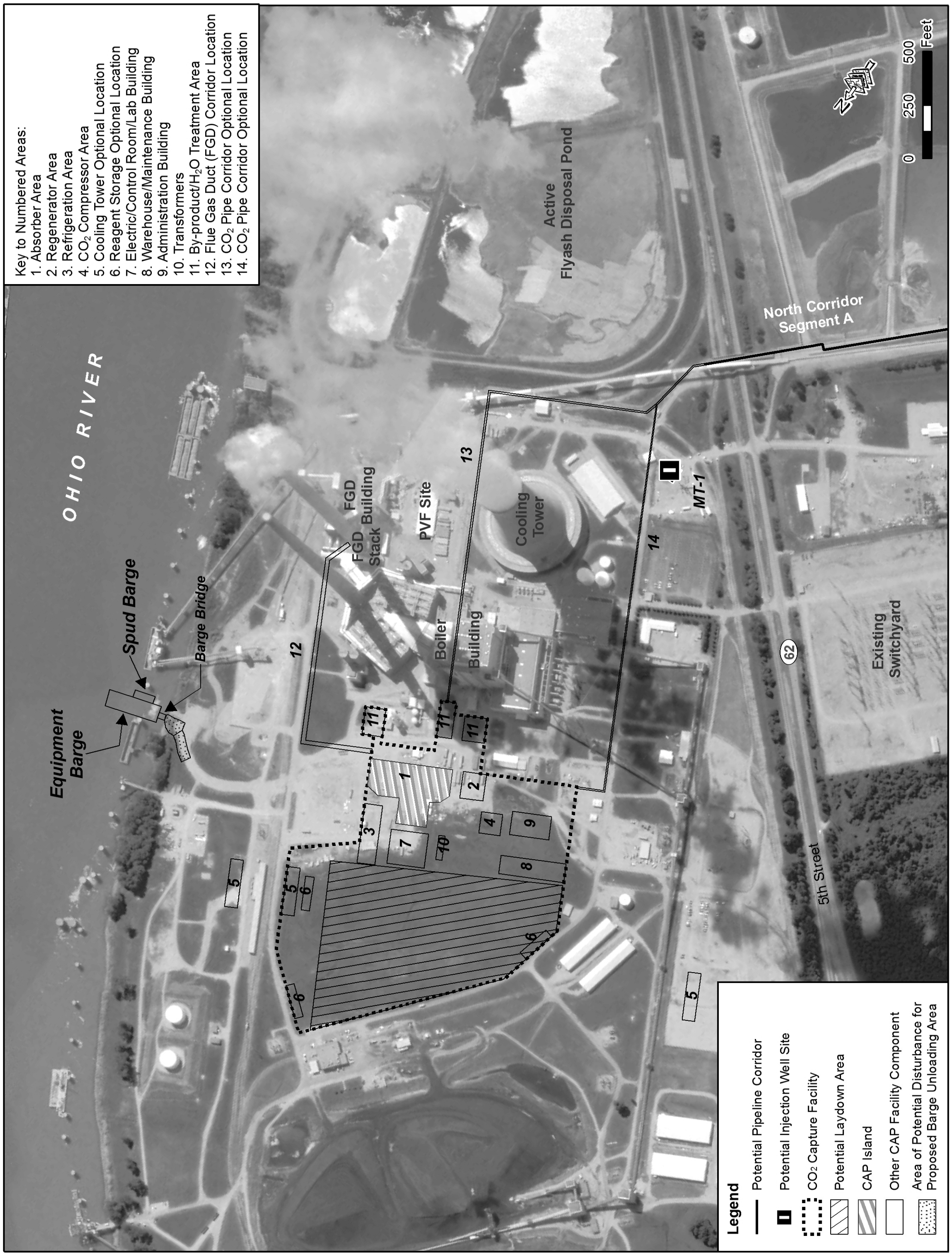

Figure 2-5. Proposed Location of the CO_2 Capture Facility

The existing Mountaineer Plant began commercial operation in 1980. The plant consists of a 1,300-MW pulverized coal-fired electric generating unit, a hyperbolic cooling tower, material handling and unloading facilities, and various ancillary facilities required to support plant operation. The plant uses (on average) approximately 10,000 tons of coal per day. Coal is delivered to the plant by barge (on the Ohio River), rail, and conveyors from a nearby coal mine located west of the site. The plant is equipped with air emissions control equipment, which includes: (1) an electrostatic precipitator for particulate control; (2) selective catalytic reduction for nitrogen oxides (NO_x) control; (3) a wet flue gas desulfurization (FGD) unit for sulfur dioxide (SO_2) control; and (4) a Trona injection system for sulfur trioxide (SO_3) control.

The existing Mountaineer Plant PVF (see Figures 2-4 and 2-5) uses Alstom's CAP system and treats approximately 20 MW of flue gas, or 1.5 percent of the total plant flue gas flow. The PVF started capturing CO_2 in September 2009 and initiated injection in October 2009. The PVF is designed to capture and store approximately 100,000 metric tons of CO_2 annually. Captured CO_2 from the PVF is injected via two onsite wells into two geologic formations (Rose Run and Copper Ridge) located approximately 1.5 miles below the plant site. The PVF also includes three deep monitoring wells used for monitoring geologic conditions and assessing the suitability of the geologic formations for future storage. The PVF would supply data to support the proposed project and would be shut down before the project initiates operation.

2.3.3.2 System Component Overview

The CO_2 capture system proposed for the Mountaineer CCS II Project would be similar to the Alstom CAP system currently operating at the Mountaineer Plant PVF, but approximately 12 times the scale. As with the PVF, the process would use an ammonia-based process solution to capture CO_2 and isolate it in a form suitable for geologic storage. The captured CO_2 stream would be cooled and compressed to a supercritical state for pipeline transport to the injection well sites. In general terms, supercritical CO_2 exhibits properties of both a gas and a liquid: supercritical CO_2 expands to fill its container like a gas, but with a density like that of a liquid. The process would be designed to remove approximately 90 percent of the CO_2 from the 235-MW slipstream of flue gas.

The existing Mountaineer Plant includes the space and infrastructure required to support the construction and operation of the CO_2 capture system. Major new equipment required would include absorbers, regenerators, pumps, heat exchangers, and refrigeration equipment. In addition, the project would require

The CAP would use ammonia-based reagents to remove CO_2 from the flue gas. The first step in the process is to cool the flue gas to temperatures necessary for CO_2 capture. The capture process involves CO_2 reacting with ammonia (NH_3) ions to form a solution containing ammonia-CO_2 salts. These reactions occur at relatively low temperatures and pressures within the absorption vessels. The solution of ammonia-CO_2 salts would then be pumped to a regeneration vessel. In the regeneration vessel, the solution is heated and the reactions are reversed, resulting in a high-purity stream of CO_2 and the regenerated reagent that is recycled back to the absorption vessel. The CO_2 stream would be scrubbed to remove excess ammonia, compressed, and then transported via pipeline to injection wells for geologic storage (See Figure 2-6).

> In a diluted form, **ammonia (NH_3)** is often used in commercial and household cleaning products.

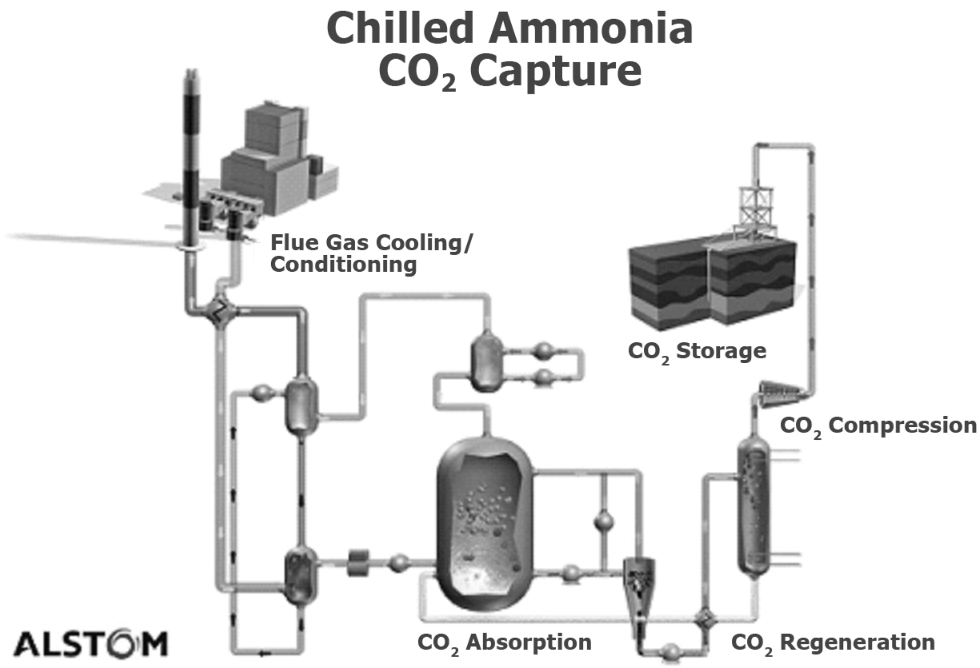

Figure 2-6. Alstom's Chilled Ammonia Process

The remainder of this section provides an expanded overview of the Alstom CAP system.

Flue Gas Cooling and Cleaning

The first step in the CAP is to cool and clean the flue gas, which enters the capture process at approximately 130 degrees Fahrenheit (°F) and contains residual amounts of SO_2, NO_x, and particulate matter (PM). The flue gas is taken from the plant's FGD system. The purpose of cooling the flue gas is to

- operate at a temperature that favors the formation of ammonium carbonate/bicarbonate;
- condense the moisture in the flue gas, which reduces the volumetric gas flow, increases the CO_2 concentration, and reduces the required size of CO_2 absorber vessels; and
- operate at a flue gas temperature that minimizes ammonia slip (unused ammonia in the downstream flue gas) from the absorption process.

During the cooling process, much of the water and most residual compounds (i.e., SO_2, SO_3, hydrogen chloride, hydrogen fluoride, and particulates) would be condensed out of the flue gas. The temperature of the circulating liquid would be reduced by the exchange of heat with water from a process cooling tower. The cooled circulating liquid is an ammonium sulfate solution that results from the reaction of ammonia and the incoming SO_2. A portion of the ammonium sulfate solution would be withdrawn from the process and treated for disposal or for commercial use as fertilizer. A sulfuric acid feed system would be provided for conditions when the incoming inlet SO_2 is not sufficiently high to react with ammonia in the flue gas leaving the CAP.

CO_2 Absorption

The second primary process step occurs in the CO_2 absorber, where CO_2 would be removed from the flue gas. The flue gas would enter the CO_2 absorber and flow through a chilled ammonia solution (i.e., ammonium carbonate/bicarbonate/carbamate). During this contact between the flue gas and the ammonia solution, the CO_2 would be absorbed by the ammonia solution before the treated flue gas exits the CO_2

absorber. The ammonia solution, which collects in the CO_2 absorber, contains the CO_2 that was absorbed from the flue gas (as ammonia-CO_2 based salts such as ammonium bicarbonate). The ammonia solution would then be transferred to the regeneration section. During the absorption process, a small amount of fresh ammonia (reagent) would be added to replenish ammonia losses from the CAP system and would be used to control the ratio of ammonia to CO_2 in the flue gas.

Anhydrous ammonia is a concentrated form of ammonia with the term anhydrous referring to the absence of water. Anhydrous ammonia is more commonly used in industrial applications.

Water Wash and CO_2 and Ammonia Stripping

After the treated flue gas exits the CO_2 absorber, it would enter a water wash system to remove ammonia vapor and recover some of the refrigeration energy input into the system. As the flue gas enters the wash column, the ammonia in the flue gas would be removed as it contacts the water. As the wash water containing ammonia exits the column, it would then enter the stripper where the ammonia in the wash water would be removed. The recovered ammonia would exit the stripper and be returned to the CO_2 absorber as reagent. The clean water would be collected in the stripper, where it would then be re-used within the water wash column to remove additional ammonia. Energy for the stripper column would be provided by steam from the Mountaineer Plant. The treated flue gas would exit the top of the water wash column and flow to the exhaust stack.

Refrigeration System

The refrigeration system in the CAP would operate at two temperature levels, utilizing mechanical chillers to remove heat from the following parts of the process:

- Flue gas after it exits the cooling and cleaning step to further reduce the flue gas moisture and to lower the flue gas temperature
- Ammonia solution after it exits the CO_2 absorber to remove heat generated by the absorption of CO_2
- Water wash recirculation stream to reduce the amount of ammonia vapor in the flue gas

The refrigeration system would use anhydrous ammonia as the refrigerant. The chiller system refrigerant was selected based on its reliability, efficiency, cost, and compatibility with the mechanical chiller compressor system. Anhydrous ammonia, a common industrial refrigerant, is the most efficient refrigerant for the CAP chiller system, as it results in the lowest energy consumption. The heat transferred from the process streams to the chiller system refrigerant, would be dissipated from the system using a cooling tower or a series of evaporative coolers.

CO_2 Regeneration and Compression

The third primary step of the process would take the CO_2-rich ammonia solution from the absorber and direct it to the CO_2 regenerator where the CO_2 would be removed from the ammonia solution. The CO_2 regenerator would contain several sections of contacting equipment that enhance the transfer of CO_2 from the liquid phase to the gas phase. The CO_2 regenerator would use steam to remove the CO_2 from the ammonia solution. The stripped CO_2 and some residual water vapor would exit the CO_2 regenerator, and the ammonia solution would then be returned to the CO_2 absorber as reagent to capture additional CO_2. The CO_2 product stream would enter the CO_2 compressor, where its pressure would be increased up to 3,000 pounds per square inch (psi) for pipeline transport and geologic storage.

Amine-Based Capture System Feasibility Study

An amine-based capture system would be similar to Alstom's CAP in that it is a post-combustion chemical absorption technology that uses a solvent to extract CO_2 from the emission stream. The solvent can then be reused after the CO_2 is separated from the solvent. One of the primary differences between the two technologies is that an amine-based system would use an amine-based solvent, which would consist of an amine or amine mixture, such as monoethanolamine (MEA). Such solvents would also typically consist of additional chemicals (corrosion inhibitors) to prevent oxidation and corrosion and to improve the reaction speed. The specific composition of Huaneng China's solvent solution is unknown at this time as it is proprietary.

Amines are organic chemicals containing nitrogen that are derived from ammonia. Amine-based CO_2 capture is widely used to extract CO_2 from natural gas. However, there is still considerable uncertainty about the full-scale application of this technology to coal-fired power generating units. This uncertainty pertains, in part, to the lack of available information on the potential transformation of amines as a result of degradation during the CO_2 capture process. In addition, limited data are available on potential emissions from amine-based capture systems at this time (MacDowell, 2010).

2.3.3.3 Construction Phase

Construction of the proposed project would be expected to start in January 2013 and take approximately 32 months to complete. This 32-month period includes approximately 8 months of start-up and commissioning activities that would occur prior to commencing commercial operations to verify that all process systems achieve project requirements. Conventional construction methods would be used to build the project. Site preparation activities would begin with grading of the site. Following site preparation, other phases of construction would include the construction of administrative facilities, installation of piles and foundations, assembly of structural steel and building enclosures, and installation of mechanical and electrical systems.

Within the existing Mountaineer Plant property, up to 14 acres of land would be required for a temporary construction staging and lay-down area for materials and equipment. Construction materials and equipment could be delivered by trucks, rail, and barges. Construction truck traffic would access the plant site from State Route 62. AEP estimates that construction would generate approximately 20 to 90 deliveries per month by truck, with the most frequent deliveries (i.e., 60-90) per month occurring from October 2013 to October 2014. Construction could require, in total, approximately 4 rail-car deliveries and 30 barge deliveries during the height of construction.

The number of construction workers would vary during the construction period, ranging from 25 to 800 persons during the various phases of construction (including construction of the pipelines and injection wells). The largest demand for construction workers is expected to occur in the latter half of 2014, when the number of construction workers would consistently range from 600 to 800 persons during construction of the mechanical and electrical systems. Electricity and construction water needs would be supplied by the existing Mountaineer Plant for construction of the CO_2 capture facility. During the construction phase, AEP would provide potable water, portable toilets, and hand-wash stations for construction workers. In the later months of the construction phase, potable water and wastewater needs for construction of the CO_2 capture facility may be incorporated into the proposed project infrastructure.

Construction-related environmental concerns would be typical of those associated with a large industrial construction project and would primarily be related to air emissions, construction traffic, fugitive dust emissions from site disturbance, and stormwater runoff from construction areas. Best management practices (BMPs) would be implemented and all necessary permits would be obtained to minimize potential concerns and to comply with all regulatory requirements during construction.

AEP would receive the delivery of larger equipment via barge traffic during construction of the CO_2 capture facility by two methods. The first method would use an existing barge unloading platform to remove material from moored barges via a mobile crane. The second method represents an upgrade to the existing unloading capabilities and would allow for larger equipment to be unloaded through the use of a temporary mobile bridge that would span the area between the river bank and the parked barge. Barges would then be unloaded by driving the payload off of the barge to an existing haul road. The area proposed for bridge unloading is within the Mountaineer Plant property along the Ohio River (See Figure 2-5). The site is adjacent to the existing barge unloading platform, extending approximately 80 to 120 feet downstream. The barges would use existing mooring cells located in the river for the adjacent bulk material unloading facilities. The barges would not touch the river bottom.

Under the first method, AEP would use the existing platform and no modifications would be required. The second method would require site preparation (vegetation clearing and grading) along the river bank to support the placement of the mobile bridge. In addition a temporary "spud barge" would be used to stabilize the delivery barge for unloading for the bridge option, which would be anchored with H-piles that would be gravity dropped on the river bottom. The piles would be removed after work has been completed. No dredging would be required within the Ohio River. The construction footprint for the second method would involve approximately 0.28 acres of land disturbance. Approximately 0.15 acres of additional land grading may be required to support improvements to the haul road and the construction of a lay down area. Construction for the barge unloading area upgrades would take approximately 2 weeks and require 10 additional construction laborers.

Construction Safety Policies and Programs

Emergency services during construction would be coordinated with the local fire departments, police departments, paramedics, and hospitals. A first aid office would be provided onsite for minor incidents. Trained and certified health, safety, and environmental personnel would be onsite to respond to and coordinate emergencies. All temporary facilities would have fire extinguishers; fire protection would be provided in work areas where welding work would be performed. In addition, other AEP existing plans and policies regarding environmental safety and health will be updated as necessary to accommodate the proposed project.

Construction Waste

Construction of the proposed project would generate typical construction wastes. The predominant waste streams would include site clearing vegetation, soils, and debris; used lube oils; surplus materials; and empty containers. Surplus and waste materials would be recycled to the extent practicable. Solid wastes (i.e., garbage and rubbish) would be collected for disposal in a licensed offsite solid waste facility (i.e., a public landfill). Scrap and surplus materials and used lube oils would be recycled or reused to the maximum practicable extent. Temporary sanitary facilities (i.e., portable toilets and hand-wash stations) would be placed in appropriate locations at the construction sites for use by construction workers. These self-contained portable units would be serviced regularly and the wastes would be collected and hauled to permitted sewage treatment facilities by licensed waste transporters.

AEP would ultimately be responsible for the proper handling and disposal of construction wastes. However, construction contractors and their employees would be responsible for minimizing the amount of waste produced by construction activities. These contractors would be expected to fully cooperate with project procedures and regulatory requirements for waste minimization and the proper handling, storage, and disposal of hazardous and non-hazardous wastes.

2.3.3.4 Operation Phase

The project demonstration phase would last for 46 months per the terms and conditions of the Cooperative Agreement between DOE and AEP. AEP would determine whether to continue operating the CCS facility after the completion of the demonstration phase. A variety of factors could affect the possible long-term operation of the CCS facility, including potential future CO_2 legislation and regulations, process performance, and economics. For the purposes of this EIS, DOE assumed the CCS facility would continue to operate for 20 years.

Operational Labor

The existing Mountaineer Plant currently employs 195 people (i.e., 110 for operations and 85 for maintenance) and operates 24 hours per day, 7 days per week, with employees working in shifts. The project would require an increase of approximately 38 full-time employees divided among shifts (i.e., an increase of approximately 19 percent over current conditions). The employees would include 26 staff for operations (i.e., 16 operators, 4 supervisors, 2 process leads, 1 process planner, 2 laboratory technicians, and 1 clerical person) and 12 staff for maintenance. All new staff would be based at the Mountaineer Plant.

Health and Safety Policies and Programs

AEP's existing Environmental, Health, and Safety Policy (EHS Policy) directs all persons and entities operating and maintaining the Mountaineer Plant on its behalf to act in a manner protective of human health, the environment, and property while complying with all applicable environmental laws and regulations. The EHS Policy would apply to the facilities and personnel associated with the project.

AEP would also update its existing Environmental Management System (EMS) at the Mountaineer Plant to include the proposed project. The EMS implements the EHS Policy within the context of federal, state, and local laws and regulations, along with specific permits and agreements that define AEP's environmental requirements. The goal of the EMS is to efficiently execute all plant activities with no deficiencies in environmental compliance.

The storage and handling of toxic or flammable materials would be conducted in compliance with EPA and Occupational Safety and Health Administration (OSHA) regulations and the National Fire Protection Association's "Guide on Hazardous Materials" (NFPA, 2010). The plant's Spill Prevention, Control, and Countermeasures (SPCC) Plan would be updated to encompass the project in compliance with federal and state regulations. Existing worker safety programs would continue to ensure that workers are aware and knowledgeable about spill containment procedures and related health and environmental protection policies.

Resource Requirements (Process Inputs)

Process Chemicals

During operation of the project, process related chemicals would be transported to the Mountaineer Plant either by truck or rail. The amount of chemicals stored at the Mountaineer Plant would be determined by the rates of consumption, customary delivery volumes available from suppliers, and the reliability of supply. In addition to regulatory requirements, AEP would follow the chemical suppliers' recommendations and procedures in storing and handling all chemicals.

The CAP technology requires the use and storage of reagents and refrigerants, some of which are considered hazardous substances. The reagent for the CAP would either be anhydrous ammonia or an aqueous ammonia solution. The refrigerant used would be anhydrous ammonia, which AEP chose after an analysis of various options (including other refrigerants such as R-134a and R-410a) considering factors such as performance, efficiency, toxicity, and economics. The CAP would also use sulfuric acid. Table 2-2 lists chemicals that would be used by and stored at the Mountaineer Plant to support the project.

AEP would design and engineer the chemical feed storage systems to include adequate valving, interlocks, and safety systems (i.e., fogging, foaming, secondary containment, berms, spill prevention, instrumentation, ambient monitoring systems, alarms, etc.) to ensure the safe operation, maintenance, and reliability of the equipment for the life of its use. AEP would consult with the design engineer and potential suppliers of anhydrous ammonia to develop the design for the ammonia storage and handling systems. AEP would also complete a preliminary hazard analysis early in the design process to review the conceptual design prior to the development of detailed engineering and design. Based on a review of hazards and in accordance with all regulatory requirements, AEP would implement the following precautions:

- Install tanks/vessels on concrete foundations with appropriate secondary containment.
- Locate ammonia reagent and sulfuric acid storage tanks outdoors with secondary containment for spills around the tank and in defined unloading areas.
- Provide nearby safety showers and eyewash stations.

- Design and install all process fluid tanks/vessels and associated equipment (i.e., pumps, piping, valves, etc.) per industry standards and codes.
- Include process drains, sumps, etc., to capture spills, leaks, and washdown of the area and equipment, consistent with West Virginia groundwater protection rules and any other applicable state or federal rule or standard pertaining to spill prevention.
- Ensure normal operation of the CAP would maintain compliance with the National Pollutant Discharge Elimination System (NPDES) permit for the facility.

Currently, each year the Mountaineer Plant receives approximately: 7,500 deliveries by large trucks and semi-trailers; 3,000 deliveries of coal and limestone by barges; and 400 deliveries by rail cars. Implementation of the project would generate additional traffic to the facility during operation. Chemicals delivered to the CO_2 capture facility (i.e., ammonia and sulfuric acid) would most likely be delivered by truck; however, deliveries may also occur by rail. Table 2-3 presents the estimated annual shipments by either truck or rail for the various chemicals proposed for use at the CO_2 capture facility at the Mountaineer Plant.

Table 2-2. Estimated CAP Chemical Inputs and Storage Quantities

Input	Usage Rate	Storage Inventory	Storage Type
Reagent			
Option 1: Anhydrous Ammonia System			
100-percent anhydrous ammonia system	650 to 850 lbs/hr	28,739 gallons (146,569 lbs) (in closed system)	Two 17,000-gallon (carbon steel) ASTs outdoors
Option 2: Aqueous Ammonia System			
29-percent aqueous ammonia	2,500 lbs/hr	54,308 gallons (396,448 lbs)	Two 28,000 gallon (carbon steel) ASTs outdoors
100-percent anhydrous ammonia for startup or upset conditions	Varies based on potential upsets; normally no usage	28,739 gallons (146,569 lbs)	Two 17,000 gallon (carbon steel) ASTs outdoors
Refrigerant			
Anhydrous ammonia	80,000 lbs/yr	157,000 gallons (800,000 lbs)	800,000 lbs in closed refrigeration system (largest single vessel approx. 250,000 lbs)
Other Process Chemicals			
Sulfuric acid	750 to 900 lbs/hr (93 percent by weight)	45,000 gallons (675,000 lbs)	45,000-gallon AST, outdoors
Ammonium sulfate (15-35 percent by weight)	NA	150,000 gallons	Four 37,500-gallon or two 75,000-gallon (carbon steel) ASTs outdoors

AST = aboveground storage tank; CAP = chilled ammonia process; lbs/hr = pounds per hour; NA = not applicable

Table 2-3. Estimated Material and Waste Transportation

Chemical	Truck Shipments[b]	Rail-car Shipments[b]
Materials		
Anhydrous ammonia[a]	180 per year	40 per year
Aqueous ammonia[c]	430 per year	100 per year
Sulfuric acid	120 per year	40 per year
Wastes or By-Products		
Ammonium sulfate	730 per year	NA

[a] Estimates include additional reagent required for startup or upset conditions or deliveries for refrigerants (up to 80,000 pounds per year; approximately two additional truck shipments per year).

[b] Delivery amounts shown would be totals for either truck shipments or for rail shipments, and are not additive.

[c] Representative of traffic to support option to use 29-percent aqueous ammonia as reagent.

NA = not applicable

An amine-based capture technology typically requires the use and storage of an aqueous amine solution and corrosion inhibitors. It would not likely require the use and storage of anhydrous ammonia. In general, amines are caustic, corrosive, and smell similar to ammonia. The quantities of process chemicals used in an amine-based capture system are unknown at this time. The feasibility study would evaluate this and other issues in more detail. Available literature indicates that amine solutions would typically be consumed at rates between 1 to 4 pounds (0.35 to 2.0 kilograms) per metric ton of CO_2 captured (Bailey, 2005). At these rates, a system capturing 1.5 million metric tons per year would require approximately 600 to 3,000 tons (540 to 2,700 metric tons) of amines for the process and for replacement of amounts lost through emissions and degradation.

Plant Flue Gas (CAP Input)

Characteristics of the flue gas that would be treated are presented in Table 2-4. During flue gas cooling, moisture, along with other constituents (e.g., SO_2, particulates, etc.) present in the flue gas, would be condensed and removed before being sent to the WWTP.

Process Water

Process water is supplied to the Mountaineer Plant from the existing river water makeup system via the Ohio River. The Mountaineer Plant consumes approximately 18.74 million gallons per day (mgd) of process water. A portion of this process water (0.07 mgd) is treated at the plant's demineralized water system before use as process water.

The proposed CAP facility would require an increase of approximately 1.9 mgd of process water, approximately 10 percent over the existing demand for the plant. This additional volume would be supplied from the Mountaineer Plant's existing water system. No new water intake structures or additional demineralized water capacity would be required.

Utilities

The plant operates a 1,300-MW pulverized coal-fired electric generating unit. The current average full-load auxiliary power demand at the Mountaineer Plant is approximately 96 MW. The additional auxiliary power demand for operation of the CO_2 capture facility would range from approximately 50 to 80 MW, which could be accommodated by the plant.

Table 2-4. Nominal Characteristics of Existing Mountaineer Plant Flue Gas (CAP Input)

Parameters		Value
Temperature		133°F
Pressure		14.5 psia
Flow Rate		631,863 scfm[a]
Components	NH_3	2.0 ppmv
	CO_2	105,993 ppmv
	N_2	680,900 ppmv
	NO_x	100 ppmv
	O_2	54,900 ppmv
	Particulates[a]	125 lbs/hr
	SO_2	80 ppmv
	SO_3	25 ppmv

[a] Estimated as 18 percent of annual total emissions from the existing Mountaineer Plant (235-MW slipstream from 1,300-MW power plant).

[b] The values presented represent nominal values from the conceptual design.

CAP = chilled ammonia process; CO_2 = carbon dioxide; °F = degrees Fahrenheit; lbs/hr = pounds per hour; MW = megawatt; N_2 = nitrogen; NH_3 = ammonia; NO_x = nitrogen oxides; O_2 = oxygen; ppmv = parts per million by volume; psia = pounds per square inch absolute (including atmospheric pressure); scfm = standard cubic feet per minute; SO_2 = sulfur dioxide; SO_3 = sulfur trioxide

The New Haven Municipal Water and Sewer Department provides potable water to the Mountaineer Plant at an average rate of approximately 11,088 gallons per day (gpd). The potable water demand for the CO_2 capture facility would be limited to the needs of a daily workforce of 38 additional employees. Based on an estimated usage rate of 30 gpd per person of potable water for consumption and sanitary needs, the daily demand would increase by approximately 1,140 gpd, an increase of approximately 10 percent. Refer to Table 2.5 for more information.

By-Products, Discharges, and Wastes (Process Outputs)

CO_2 Stream

Characteristics of the CO_2 product stream are presented in Table 2-6. The pressure of the CO_2 product stream leaving the capture process would minimize the need for additional CO_2 compression equipment and related operating costs.

Industrial Wastewater

Currently, Mountaineer Plant effluent streams containing raw materials, chemicals, oil, or process water are directed for treatment at the plant's WWTP prior to discharge (ultimately to the Ohio River). The Mountaineer Plant currently discharges treated wastewater to surface waters under an NPDES permit. The Mountaineer Plant discharges noncontact cooling water and treated process water through 20 different outlets located throughout the plant site to the Ohio River, Little Broad Creek, and an unnamed tributary of the Ohio River (WVDEP, 2006a).

Table 2-5. Utility Requirements for Existing Mountaineer Plant and Proposed CO_2 Capture Facility

Utility	Existing Plant	Proposed CO_2 Capture Facility		Utility Provider
		Construction	Operation	
Auxiliary Power	96 MW (full-load auxiliary power demand)	Negligible	50 to 80 MW[a]	Mountaineer Plant. Capacity: 1,300 MW
Potable Water	11,088 gpd	1,500 to 45,600 gpd[b]	2,200 gpd[c]	New Haven Water Facility
Process Water	18,740,000 gpd	• 2,500,000 gallons over 32-month construction phase (for dust control and general washdown) • 600,000 gallons of demineralized water for hydrotesting and system startup	• 1,800,000 gpd makeup water rate • 72,000 gpd demineralized water	• Supplied by Mountaineer's existing river water makeup system • Mountaineer Plant demineralized water system
Sanitary Wastewater	11,770 gpd	1,500 to 48,000 gpd[b,d]	2,300 gpd[c]	New Haven Sanitary Waste Facility

[a] Represents both steam and electrical demand.
[b] Based on 25 to 800 construction workers.
[c] Based on 38 permanent employees.
[d] Sanitary wastewater during construction would be handled through either the public utility or portable restrooms, estimated as follows: waste from between 50 to 100 personnel would be directed to the NHSWF, the remainder of the wastewater would be disposed of offsite through contracts with portable restroom providers. The portable units would be collected and hauled to sewage treatment facilities in the area by licensed waste transporters. As a worst-case scenario, it is assumed that the NHSWF would ultimately receive the wastewater from the portable restrooms.
AEP = American Electric Power Service Corporation; CO_2 = carbon dioxide; gpd = gallons per day; MW = megawatt; NHSWF = New Haven Sanitary Waste Facility

Table 2-6. Estimated Characteristics of Product Stream Exiting the CAP for Geologic Storage

Parameters		Value
Temperature		90 to 110°F
Pressure		1,500 to 3,000 psi
Total Mass Rate		445,498 lbs/hr
Volumetric Rate		60,433 scfm
Components	NH_3	< 50 ppmv
	CO_2	$\geq$ 99.5 percent by volume
	N_2	< 100 ppmv
	H_2O	< 3,000 ppmv

CAP = chilled ammonia process; CO_2 = carbon dioxide; °F = degrees Fahrenheit; lbs/hr = pounds per hour; H_2O = water; N_2 = nitrogen; NH_3 = ammonia; ppmv = parts per million by volume; psi = pounds per square inch; scfm = standard cubic feet per minute

The Mountaineer Plant generates approximately 17.3 mgd of industrial wastewater (see Table 2-7). Industrial wastewater is treated by the onsite WWTP prior to discharge to the Ohio River. The treatment process generates 0.14 mgd of sludge, which is disposed of at AEP's Little Broad Run Landfill.

Table 2-7. Industrial Wastewater Estimates for Mountaineer Plant and Proposed CAP Facility

Industrial Wastewater	Existing Plant	Proposed CO_2 Capture Facility		Utility Provider
		Construction	Operation	
Industrial Wastewater	17,300,000 gpd	NA	• Off-spec ammonium sulfate solution (15-35 percent by weight): quantity would vary[a] • Wastewater from the flue gas cooling/cleaning process; quantity varies • Absorber building sump wastewater; quantity varies	• Onsite treatment system to evaporate water and produce concentrated dry ammonium sulfate product[b] • Onsite wastewater treatment or reuse by the Plant[b]

[a] On-spec ammonium sulfate is a marketable by-product.

[b] The project may use the existing wastewater treatment capacity at the plant or a new WWTP would be built for the proposed project, and treated water discharged via existing plant outfall.

CAP = chilled ammonia process; CO_2 = carbon dioxide; gpd = gallons per day; NA = not applicable

The current onsite WWTP may have sufficient capacity to handle additional process flow from the CAP facility. However, should the existing system prove incapable of providing the necessary capacity, a new industrial WWTP would be constructed to treat effluent streams from the CO_2 capture facility. The WWTP would be constructed within the footprint of the CO_2 capture facility. Effluent from the new WWTP would be sent to the existing plant's permitted outfall.

Other wastewater from the CO_2 capture facility may include purge streams (i.e., from the flue gas cooling and ammonia stripping processes), cooling tower blowdown, potential process leaks or spills, and maintenance activities (e.g., washdown). Wastewater from these sources would be managed by

- reuse in the CAP;
- reuse in other Mountaineer Plant processes (e.g., FGD system);
- monitoring, treatment, and release to a permitted outfall; or
- collection for offsite disposal.

By-Products

The by-product stream from the CAP facility under normal operations would consist of an ammonium sulfate solution (15-35 percent by weight). There is potential for this by-product stream to be sold for agricultural use in liquid or concentrated dry solid form. If the market warrants, AEP would provide an onsite treatment system to evaporate water from the solution to produce a concentrated dry ammonium sulfate product at a maximum rate of 2,500 pounds per hour (lbs/hr). The dry product would be stored onsite and transported by truck to regional agricultural product suppliers. If the market is not available, the by-product would be processed with calcium oxide (lime) to form gypsum and would be sent to the AEP Little Broad Run Landfill, located onsite.

Solid Waste

The potential exists for infrequent generation of off-specification by-product waste from the proposed CO_2 capture facility. Any by-product of insufficient quality to have a marketable value would be considered off-specification and would be treated as a waste. Long-term maintenance of process equipment (e.g., absorber vessels, regenerator, stripping systems, etc.) to replace packing and system components is expected. The material removed and/or waste generated as part of this required maintenance is not expected to be hazardous. Routine maintenance of process components (e.g., pumps, valves, etc.) is not expected to generate significant amounts of waste. Any waste generated would be properly managed and disposed of at a suitable waste disposal facility.

In the event of a process malfunction, maintenance may be required. These events could produce a waste product not considered in the maintenance scenarios above; such wastes may or may not be hazardous. These events would be rare, treated on a case-by-case basis, and not expected during normal operation. The waste material generated as a result of these activities would be handled according to applicable laws and regulations, plant operations and maintenance standards, risk management plans (RMP), Material Safety Data Sheets recommendations, and other industry or agency standards for proper handling and disposal. These types of emergency events would be addressed in a Hazards and Operability study prior to operations, such that potential problems and risks are identified, employee awareness is raised, mitigations of risk are implemented, and emergency procedures are effective.

An amine-based capture system would have the potential to generate amine wastes. The composition of amine waste would depend on the specific amine solvent solution used, but would typically include spent amine solvent, amine degradation products, and corrosion inhibitors (Thitakamol, 2007). A typical CO_2 capture process using an amine-based solvent with a capacity to capture 1 million metric tons of CO_2 annually might be expected to generate 330 to 3,300 tons (300 to 3,000 metric tons) of amine waste annually (Bellona, 2009). There is still considerable uncertainty about the degradation products that would result from a large-scale amine-based capture system. Available literature indicates that potential degradation products could be determined to be hazardous waste due to corrosivity and toxicity. If so, such wastes would have to be transported to a licensed hazardous waste disposal facility, and would have to be properly managed. The feasibility study would evaluate this issue in more detail.

Air Emissions

The proposed CAP system would be designed to achieve a 90 percent CO_2 capture efficiency during steady-state operations, which equates to approximately 1.5 million metric tons per year (tpy) of CO_2 emissions reduction. While the CAP may offer the additional benefit of reducing other residual emissions, these reductions are ancillary and not the focus or claim of the CAP process. The CAP is not expected to increase the emission rates of any regulated emissions. Therefore, the Mountaineer Plant would be expected to continue operating within the limits of its existing Title V air permit.[1] The treated flue gas exiting the CAP would be returned to the existing Mountaineer Plant stack for discharge. Table 2-8 summarizes the estimated concentrations of the treated flue gas exiting the CAP facility.

Truck and rail transport to and from the CO_2 capture facility would generate combustion-related emissions, as well as fugitive dust emissions. Two new cooling towers would be required for the project, which would have the potential to generate particulate emissions. These emissions are expected to be minor or de minimis in quantity, especially since a drift elimination system would be used. Please refer to Section 3.1, Air Quality and Climate, for further discussion on potential emissions from the project.

An amine-based capture system would have the potential to emit amines to the atmosphere. The amount and characteristics of amines that could be emitted depends on the size of the gas stream from which CO_2 is being captured and other factors. Annual amine emissions for a large-scale amine-based CO_2 capture system might be in the range of 44 to 176 tons (40 to 160 metric tons) for a system capturing approximately one million metric tons of CO_2 annually (Bellona, 2009). The feasibility study would evaluate this issue in more detail.

2.3.4 CO_2 Pipelines

The project would transport captured CO_2 via pipelines to injection wells located within 12 miles of the Mountaineer Plant. The ultimate configuration of the pipeline routes would depend on which potential

[1] The Mountaineer Plant's current Title V permit does not contain emission limits for ammonia. The proposed CO_2 capture facility would emit approximately 10 parts per million or less of ammonia, which is approximately equal to, or less than, 14 pounds per hour.

injection well sites would be used. As described in Section 2.3.5.1, AEP is in the process of determining the combination of sites that would be used.

Table 2-8. Estimated Characteristics of Treated Flue Gas Exiting the Capture Facility for Return to the Existing Mountaineer Plant Stack

Parameter		Value
Temperature		114°F
Pressure		14.7 psia[a]
Flow Rate		528,975 scfm
Components	NH_3	< 10 ppmv
	CO_2	13,000 ppmv
	N_2	813,000 ppmv
	NO_x	< 100 ppmv
	O_2	67,000 ppmv
	Particulates	< 50 lbs/hr
	SO_2	< 20 ppmv
	SO_3	< 10 ppmv

[a] Maximum quantities.

CO_2 = carbon dioxide; °F = degrees Fahrenheit; lbs/hr = pounds per hour; N_2 = nitrogen; NH_3 = ammonia; NO_x = nitrogen oxides; O_2 = oxygen; ppmv = parts per million by volume; psia = pounds per square inch absolute (including atmospheric pressure); scfm = standard cubic feet per minute; SO_2 = sulfur dioxide; SO_3 = sulfur trioxide.

2.3.4.1 Location and Background

Lands between the Mountaineer Plant and some of the injection well properties are not entirely owned by AEP; therefore, AEP would establish a pipeline corridor and obtain legal ROWs, setbacks, and easements as needed. AEP identified pipeline corridors to each of the injection well sites (see Figure 2-7 and Table 2-9). AEP's pipeline would follow existing, previously disturbed AEP electrical transmission line corridors to the extent possible. This would reduce the level of potential environmental and socioeconomic impacts that could result from establishing new ROWs. However, existing landowner agreements would need to be re-visited. General descriptions of potential pipeline corridors are provided below:

- **North Corridor** (2.69 miles) - Beginning at the Mountaineer Plant property, extending generally southward before terminating in the vicinity of the Borrow Areas. The North Corridor is located entirely within AEP-owned property and lies almost entirely within, or immediately adjacent to, an existing transmission ROW. Much of the land traversed by the North Corridor is currently developed or has been previously disturbed.
- **South Corridor** (4.36 miles) - Begins at the southern end of the North Corridor and extends southward to Gill Road (County Route 20). The majority of the South Corridor lies within an existing transmission ROW. The only exception is a small section of the corridor located between County Route 12/8 and County Route 15, in which the proposed corridors briefly bends toward the east into wooded areas. A majority of the northernmost one-third of the South Corridor, north of Blessing Road, crosses through agricultural land and cattle pasture.
- **Blessing Road Corridor** (0.67 miles) - Loosely follows along Blessing Road from the South Corridor eastward to the Eastern Sporn property. The Blessing Road Corridor, which does not follow an existing transmission ROW, also crosses through a portion of the East Corridor (described below). The Blessing Road Corridor is located on the north side of Blessing Road and

crosses through some privately-owned properties and meadows; only two small segments of this corridor traverse through wooded areas.

- **East Corridor** (1.42 miles) - Approximately 1.42 miles in length, it does not follow an existing transmission ROW. The corridor begins near the northern end of the South Corridor. It extends eastward, turns south, and then bends back to the west, reconnecting with the South Corridor just south of Blessing Road. The northernmost approximately one-fourth of the East Corridor crosses through cattle pasture, while the southernmost approximately one-fourth crosses through meadow and one privately-owned property. In between, the East Corridor predominantly crosses through wooded areas.
- **Eastern Sporn Corridor** (1.72 miles) - Generally runs in a north-south direction, beginning at a portion of the South Corridor and terminating at the Eastern Sporn property. The Eastern Sporn Corridor lies completely within or immediately adjacent to existing transmission ROWs for its entire length.
- **Jordan West Corridor** (2.20 miles) - Extends southward from the southern end of the South Corridor to the Jordan property. It predominantly lies within an existing transmission ROW, with the exception of two short sections of the corridor, that traverse through wooded areas.
- **Jordan East Corridor** (2.19 miles) - Extends southward from the southern end of the South Corridor to the Jordan property. The Jordan East Corridor meets the South Corridor at the same location as the Jordan West Corridor. However, the Jordan East Corridor takes a more easterly route towards the south, following an existing transmission ROW for nearly its entire length.
- **Western Sporn Corridor** (3.68 miles) - Runs in an east-west direction, extending westward from the North Corridor on AEP property to Dave Foglesong Road (County Route 3/3). This corridor traverses along and within the north side of an existing double transmission ROW. The corridor runs through or adjacent to several open fields/meadows, and a corn field.
- **Foglesong Corridor** (1.16 miles) - The Foglesong Corridor extends from the terminus of the Western Sporn Corridor westward to the Western Sporn property. The corridor follows along and adjacent to the north side of Dave Foglesong Road (County Route 3/3).

Pipeline corridors have been divided into segments to facilitate the alternative routing options. These segments intersect with other corridors or injection well sites. For example, the North Corridor is comprised of three corridor segments. The first segment (North Corridor Segment A) starts at the Mountaineer Plant and ends at the intersection of the North Corridor and Western Sporn Corridor, while the second (North Corridor Segment B) continues to Injection Well Site BA-1 at the Borrow Area. The third segment (North Corridor Segment C) continues from Injection Well Site BA-1 to the end of the corridor where it meets the South Corridor. The corridors and corridor segments are labeled on Figure 2-7. The injection well properties and possible injection well sites are discussed in Section 2.3.5 and also labeled in Figure 2-7.

The pipeline corridors that have been identified by AEP allow for pipeline routes from the Mountaineer Plant to the potential injection well properties and alternative routes to both the Eastern Sporn Tract and Jordan Tract. Each alternative route consists of a different set of pipeline corridor segments. There are four alternative route options to the Eastern Sporn and Jordan properties. Table 2-9 details the corridor segments that comprise each of the routes and alternative routes to each injection well site.

Pipeline routing on the properties is not included in Table 2-9 as it would depend on the specific location of the injection well site. The final length of pipeline from the end of the pipeline corridor to the injection well is called a pipeline spur.

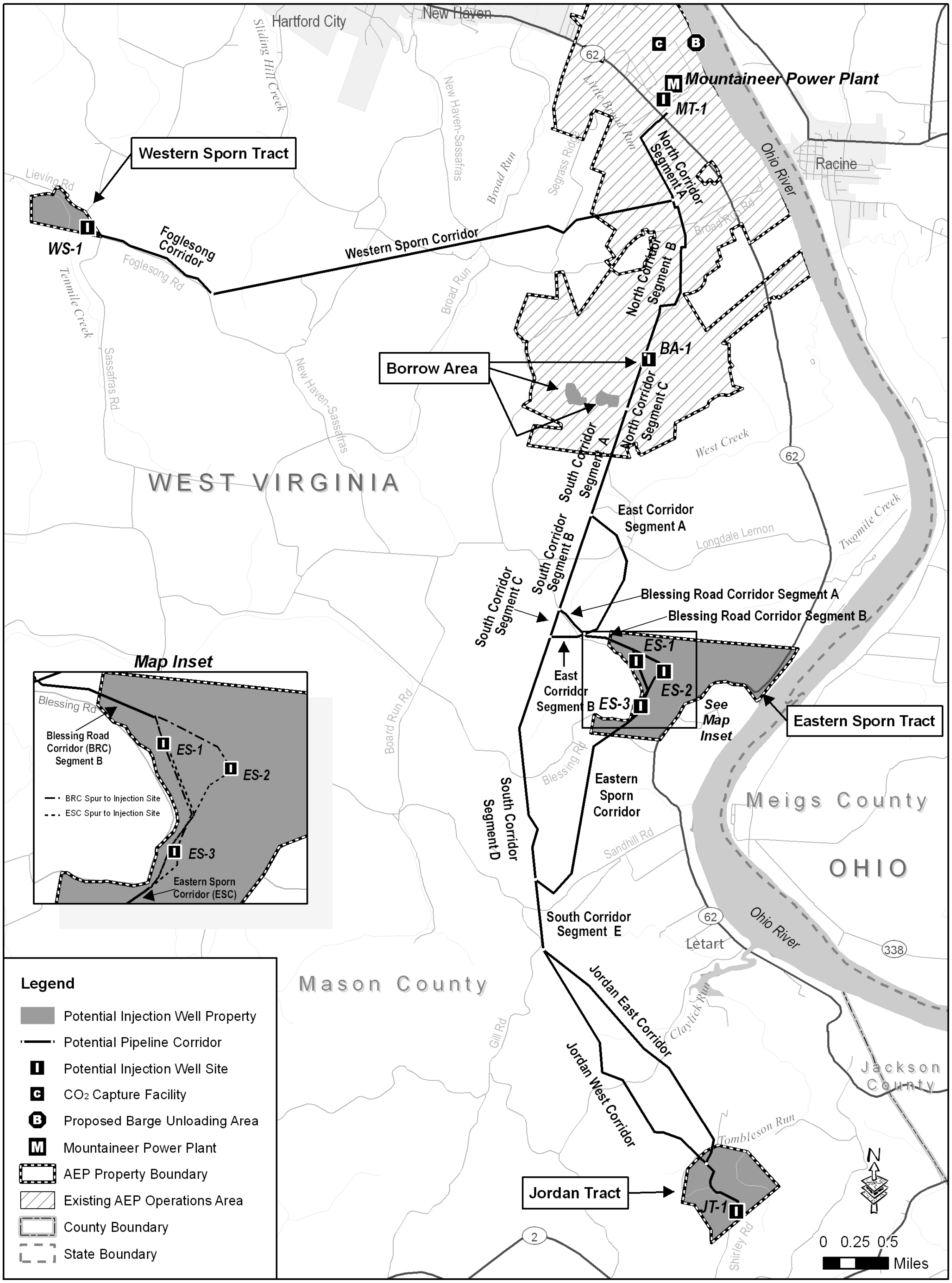

Figure 2-7. Potential CO_2 Pipeline Corridors

Table 2-9. Potential CO_2 Pipeline Corridors and Alternative Routes

Potential Injection Well Property	Route or Alternative Route	Route Length (miles)	Segments That Comprise Route	Segment Length (miles)
Mountaineer Plant	Plant Routing	0.13	NA	0.13
Borrow Area	Borrow Area Route	2.24	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
Eastern Sporn Tract	Eastern Sporn Route 1	5.00	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
			North Corridor Segment C	0.45
			South Corridor Segment A	0.87
			South Corridor Segment B	0.77
			Blessing Road Corridor Segment A	0.27
			Blessing Road Corridor Segment B	0.40
	Eastern Sporn Route 2	8.22	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
			North Corridor Segment C	0.45
			South Corridor Segment A	0.87
			South Corridor Segment B	0.77
			South Corridor Segment C	0.22
			South Corridor Segment D	1.95
			Eastern Sporn Corridor	1.72
	Eastern Sporn Route 3	5.11	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
			North Corridor Segment C	0.45
			South Corridor Segment A	0.87
			East Corridor Segment A	1.15
			Blessing Road Corridor Segment B	0.40
	Eastern Sporn Route 4	8.65	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
			North Corridor Segment C	0.45
			South Corridor Segment A	0.87
			East Corridor Segment A	1.15
			East Corridor Segment B	0.27
			South Corridor Segment D	1.95
			Eastern Sporn Corridor	1.72

Table 2-9. Potential CO_2 Pipeline Corridors and Alternative Routes *(Continued)*

Potential Injection Well Property	Route or Alternative Route	Route Length (miles)	Segments That Comprise Route	Segment Length (miles)
Jordan Tract	Jordan Route 1	9.25	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
			North Corridor Segment C	0.45
			South Corridor Segment A	0.87
			South Corridor Segment B	0.77
			South Corridor Segment C	0.22
			South Corridor Segment D	1.95
			South Corridor Segment E	0.55
			Jordan West Corridor	2.20
	Jordan Route 2	9.24	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
			North Corridor Segment C	0.45
			South Corridor Segment A	0.87
			South Corridor Segment B	0.77
			South Corridor Segment C	0.22
			South Corridor Segment D	1.95
			South Corridor Segment E	0.55
			Jordan East Corridor	2.19
	Jordan Route 3	9.68	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
			North Corridor Segment C	0.45
			South Corridor Segment A	0.87
			East Corridor Segment A	1.15
			East Corridor Segment B	0.27
			South Corridor Segment D	1.95
			South Corridor Segment E	0.55
			Jordan West Corridor	2.20
	Jordan Route 4	9.67	North Corridor Segment A	0.85
			North Corridor Segment B	1.39
			North Corridor Segment C	0.45
			South Corridor Segment A	0.87
			East Corridor Segment A	1.15
			East Corridor Segment B	0.27
			South Corridor Segment D	1.95
			South Corridor Segment E	0.55
			Jordan West Corridor	2.19

Table 2-9. Potential CO_2 Pipeline Corridors and Alternative Routes *(Continued)*

Potential Injection Well Property	Route or Alternative Route	Route Length (miles)	Segments That Comprise Route	Segment Length (miles)
Western Sporn Tract	Western Sporn Route	5.69	North Corridor Segment A	0.85
			Western Sporn Corridor	3.68
			Foglesong Corridor	1.16

CO_2 = carbon dioxide; NA = not applicable

2.3.4.2 System Component Overview

Captured CO_2 would be transported via pipelines (located primarily underground) to the injection wells. The pipelines would be similar in design and operation to other pipelines (e.g., natural gas) common in West Virginia. The CO_2 pipelines would be designed, tested, and operated in accordance with all applicable federal regulations. These include the U.S. Department of Transportation (DOT) regulations and the U.S. Department of Labor OSHA requirements. These regulations are intended to ensure adequate protection of the public and to prevent pipeline accidents and failures. The proposed pipelines would be sited in accordance with applicable federal regulations, including 49 CFR 195, *Transportation of Hazardous Liquids by Pipeline*. Applicable pipeline siting requirements include Section 195.210, *Pipeline Location*:

- Pipeline ROWs must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly.
- No pipeline may be located within 50 feet of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches of soil cover in addition to that prescribed in 49 CFR 195.248 (Cover Over Buried Pipeline).

The main components of the proposed pipeline would include pipeline materials, controls, and monitoring systems. The pipeline would be constructed of carbon steel and range from approximately 8 to 12 inches in nominal diameter. The pipelines would operate at pressures up to 3,000 psi. AEP would prepare the final design of the pipeline during the design phase of the project.

All pipelines would be installed below ground, except for locations where the pipeline would cross a vertical rock outcropping. The only pipeline features that would potentially be visible along the route would be: (1) minimal locations where the pipeline crosses a vertical rock outcropping; (2) pipeline location markers (primarily positioned at road and stream crossings, fence lines, or in areas where pipeline is above the ground surface); and (3) cathodic protection test posts located on each side of all road crossings. The location posts would be 4.5-feet tall and display the mileage as well as a cautionary statement such as, "In case of emergency or before digging, call (owner's name and telephone number)."

AEP would follow common industry practice for pipelines of this length and install shut-off valves at the beginning and end of each pipeline route. Refer to Table 2-10 for more specific characteristics of each potential CO_2 pipeline route, including number of stream crossings, wetland areas within the construction ROWs, and number of residences within 500 and 1,000 feet of the potential routes. There are no hospitals or schools located within 1,000 feet of any of the pipeline routes.

Table 2-10. Summary of Potential CO_2 Pipeline Routes

Pipeline Route Name	Route Length (miles)	Existing ROW (miles)	New ROW (miles)	Number of Stream Crossings	Wetland Areas within Construction ROW (acres)	Residences near Pipeline, within[a]:	
						1000 ft	500 ft
Plant Routing	0.13	0.13	0	0	0	0	0
Borrow Area Route	2.24	2.24	0	7	5.36	0	0
Eastern Sporn Route 1	5.00	4.34	0.66	24	5.54	2	1
Eastern Sporn Route 2	8.22	8.03	0.18	48	6.00	12	2
Eastern Sporn Route 3	5.11	3.57	1.54	25	5.55	5	1
Eastern Sporn Route 4	8.65	7.09	1.56	38	6.05	16	3
Jordan Route 1	9.25	8.23	1.02	53	6.21	11	4
Jordan Route 2	9.24	8.90	0.34	57	6.07	11	3
Jordan Route 3	9.68	7.27	2.41	55	6.26	15	5
Jordan Route 4	9.67	7.94	1.73	59	6.14	15	4
Western Sporn Route	5.69	4.5	1.19	34	5.68	42	19

[a] There are no hospitals or schools located within 1,000 feet of any of the pipeline routes.
CO_2 = carbon dioxide; ft = feet; ROW = right-of-way

2.3.4.3 Construction Phase

Typical pipeline construction corridors would require a construction ROW of approximately 80 feet to 120 feet in width. However, in stretches with steep side slopes, the ROW width may need to be up to 20 percent wider (i.e., up to approximately 144 feet) to achieve a workable and safe ROW grade. The permanent pipeline ROW would be approximately 50 feet wide. AEP would obtain the required ROWs for both the pipeline corridors and construction access roads. Figure 2-8 shows typical pipeline construction methods. Construction of the proposed pipelines would take place over approximately 18 months beginning in July 2013.

Construction techniques may include excavated trenching, boring, tunneling, and directional drilling. Typical pipeline construction equipment would include pipelayers, track hoe excavators, trenching machines, mobile cranes, bulldozers, motor graders, dump trucks, front-end loaders, portable welding rigs, radiographic inspection equipment, pipe bending machines, water pumps and filters, transport trucks, and crew trucks and buses. The size and quantity of equipment would vary based on the length and diameter of the pipe, as well as the terrain characteristics and obstacles that would be traversed by the pipeline. During pipeline construction, materials would be staged adjacent to the pipeline ROWs or trucked in as necessary.

Blasting would be required where consolidated rock cannot be trenched or ripped; however, locations where blasting would be needed are unknown at this time. To ensure that blasting impacts are minimal, AEP would develop a blasting plan for safety purposes and would notify occupants of nearby buildings, residences, agricultural areas, and other areas of public gathering sufficiently in advance. Blasting, if required, would occur on an intermittent basis over a relatively short period of time.

During site preparation, the full width of the ROW (i.e., including temporary and final ROW) would be cleared of trees and brush. After clearing, the ROW would be graded so that equipment could operate safely. Next, the trench for the pipeline would be excavated. The soil 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. Welds would be radio-graphically inspected before a protective coating is applied to welded areas, and the pipe lowered into the trench.

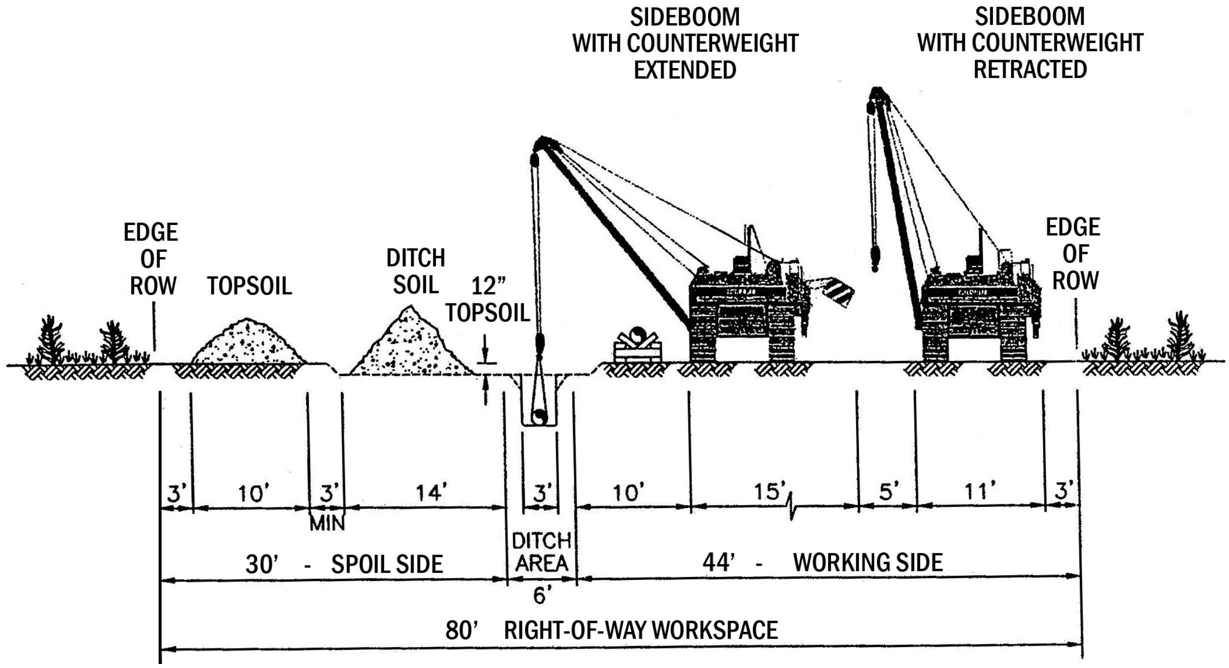

Figure 2-8. Typical Pipeline Construction Methods

Source: INGAA, 1999
min = minimum; ROW = right-of-way; ‘ = feet; “ = inches

The topsoil would be temporarily stored separately from other excavated material and in a manner to minimize erosion in accordance with the stormwater permit. A majority of the excavated material would be returned to the trench and the site would be restored to its original grade. The topsoil would be replaced as the upper-most soil layer following pipeline construction. Excavated rock, like most other spoils from the trench, would likely be placed back in the trench after suitable backfill material has been placed around the pipe. In cultivated land, rock would not be returned to the trench so that farming practices would not be affected.

Typically, the pipeline would be covered by a minimum of 3 feet of compacted soil. The pipeline would be buried deeper (minimum of 4 feet in cultivated areas) or would be encased in reinforced concrete when needed to accommodate planned surface activities or when crossing under roadways. Techniques for crossing streams would depend on considerations of safety, environmental compliance, and efficiency factors specific to the particular location. After lowering and backfilling of the pipeline in the trench, the pipeline would be tested by filling the pipeline (or section of pipeline) with water and pressure-tested using pressures higher than the normal operating pressures (i.e., hydrostatic testing, or hydrotesting). After pipeline installation is complete, the ROW would be revegetated.

Wastes generated from the construction of the proposed CO_2 pipeline would primarily consist of land clearing waste and spent hydrotesting water generated during the hydrostatic testing of the pipelines. The pipeline contractor would be tasked with providing an acceptable plan for offsite disposal (i.e., landfills, other construction areas needing fill material, etc.) of any debris that is not suitable for placement on the ROWs.

Construction water use would be heaviest during the hydrostatic testing of the pipelines. Hydrotesting water would be reused for subsequent pressure tests if practicable. Spent hydrotesting water would be tested to properly characterize the waste prior to disposal. It could be routed to the Mountaineer Plant’s outfall for discharge in accordance with the project’s NPDES permit.

Laborers for the construction of the pipelines would largely be drawn from the pool of workers discussed under Section 2.3.3.3. AEP would provide the construction workers with potable water, portable toilets, and hand-wash stations.

2.3.4.4 Operation Phase

The DOT Pipeline and Hazardous Materials Safety Administration would have regulatory jurisdiction over the proposed CO_2 pipeline. The CO_2 pipeline would be designed, operated, and maintained in accordance with federal DOT Safety Standards in 49 CFR 195. The safety standards specified in 49 CFR 195 require the pipeline operator (AEP) to

- develop and implement an emergency plan (see below), working with local fire departments and other agencies, to identify personnel to be contacted, equipment to be mobilized, and procedures to be followed in responding to a hazardous condition caused by the pipeline or associated facilities;
- establish and maintain a liaison with the appropriate fire, police, and public officials to coordinate mutual assistance when responding to emergencies; and
- establish a continuing education program to enable customers, the public, government officials, and those engaged in excavation activities to recognize a CO_2 pipeline emergency and report it to appropriate public officials.

Key elements of any emergency plan would include procedures for

- receiving, identifying, and classifying emergency events such as gas leakage, fires, explosions, and natural disasters;
- establishing and maintaining communications with local fire, police, and public officials and coordinating emergency responses;
- making personnel, equipment, tools, and materials available at the scene of an emergency;
- proactive protection for people and insuring human safety from actual or potential hazards; and
- emergency shutdown of the system and safely restoring service.

Before placing a pipeline in service, AEP would prepare a procedure manual for operation and maintenance of the pipeline. During operations, AEP would monitor and maintain the pipelines in compliance with all regulatory requirements. Typical monitoring and maintenance procedures could include

- population density survey, once every 2 years;
- ROW inspection, 26 times each year (i.e., every 2 weeks);
- valve maintenance and inspection, twice each year;
- emergency systems check, once each year;
- rectifier maintenance, 6 times each year;
- cathodic-protection survey, once each year;
- internal inspection of the pipeline using an electronic tool, every 7 years or more frequently if necessary;
- check of overpressure safety devices, once each year; and
- public awareness and damage prevention program, once each year.

ROW inspections would be conducted to identify dry vegetation, soil erosion, unauthorized encroachment, or other conditions that could result in a safety hazard or require preventative repairs or maintenance. Inspections would also ensure that no third party activity would likely jeopardize the pipeline (e.g., via excavation). Cathodic protection surveys would be conducted annually to ensure that corrosion protection is adequate.

Inspection activities may require that pipeline "pigging" be performed occasionally to displace water during or after long periods of reduced flowrate or to displace contaminants after an upset condition. Ongoing design would determine the necessary procedures to protect the pipeline when it is not in service. Options under consideration include the application of protective pipeline linings and/or the use of nitrogen or other inert gas filling to minimize potential performance or integrity concerns. None of the maintenance activities for the proposed pipeline are expected to produce any appreciable quantities of waste.

Pigging refers to the practice of using pipeline inspection gauges or 'pigs' to perform various operations on a pipeline without stopping the flow of the product in the pipeline. These operations include, but are not limited to, cleaning and inspection of the pipeline.

2.3.5 CO_2 Injection Wells

2.3.5.1 Location and Background

Geologic formations capable of storing CO_2 include oil- and gas-bearing formations, saline formations, basalts, deep coal seams, and oil- or gas-rich shales. Not all geologic formations are suitable for CO_2 storage. Some formations are too shallow and others have low permeability (i.e., the ability of rock to transmit fluids through pore spaces) or poor confining characteristics. Formations suitable for CO_2 storage have sufficient permeability and porosity to allow for injection and movement of CO_2, as well as adequate confinement layers to prevent upward migration. These characteristics are common with formations that have thick accumulations of sediments or rock layers, permeable layers saturated with saline water (i.e., saline formations), extensive covers of low permeability sediments or rocks acting as seals (i.e., caprock), and lack of transmissive faults (i.e., gaps that allow gas or fluid to escape).

The captured CO_2 would be transported by pipeline to injection wells for permanent geologic storage. AEP is considering five AEP-owned properties for the location of the CO_2 injection wells:

- **Mountaineer Plant** - Located near the proposed CO_2 capture facility (see Figure 2-9)
- **Borrow Area** - 2.24 miles south of the Mountaineer Plant (see Figure 2-10)
- **Eastern Sporn Tract -** 4.5 miles south of the Mountaineer Plant (see Figure 2-11)
- **Jordan Tract -** 10.5 miles south of the Mountaineer Plant (see Figure 2-12)
- **Western Sporn Tract** - 6 miles west of the Mountaineer Plant (see Figure 2-13)

AEP identified the Mountaineer Plant and the Borrow Area as preferred injection properties. AEP prefers the Jordan Track property over the Eastern Sporn Tract. The Western Sporn Tract is the least preferred property due to its small size, potential for increased environmental impacts, increased project construction and operation expenses associated with a required separate pipeline route, and the potential need to upgrade local access roads along the CO_2 pipeline corridor. The ultimate location of the injection

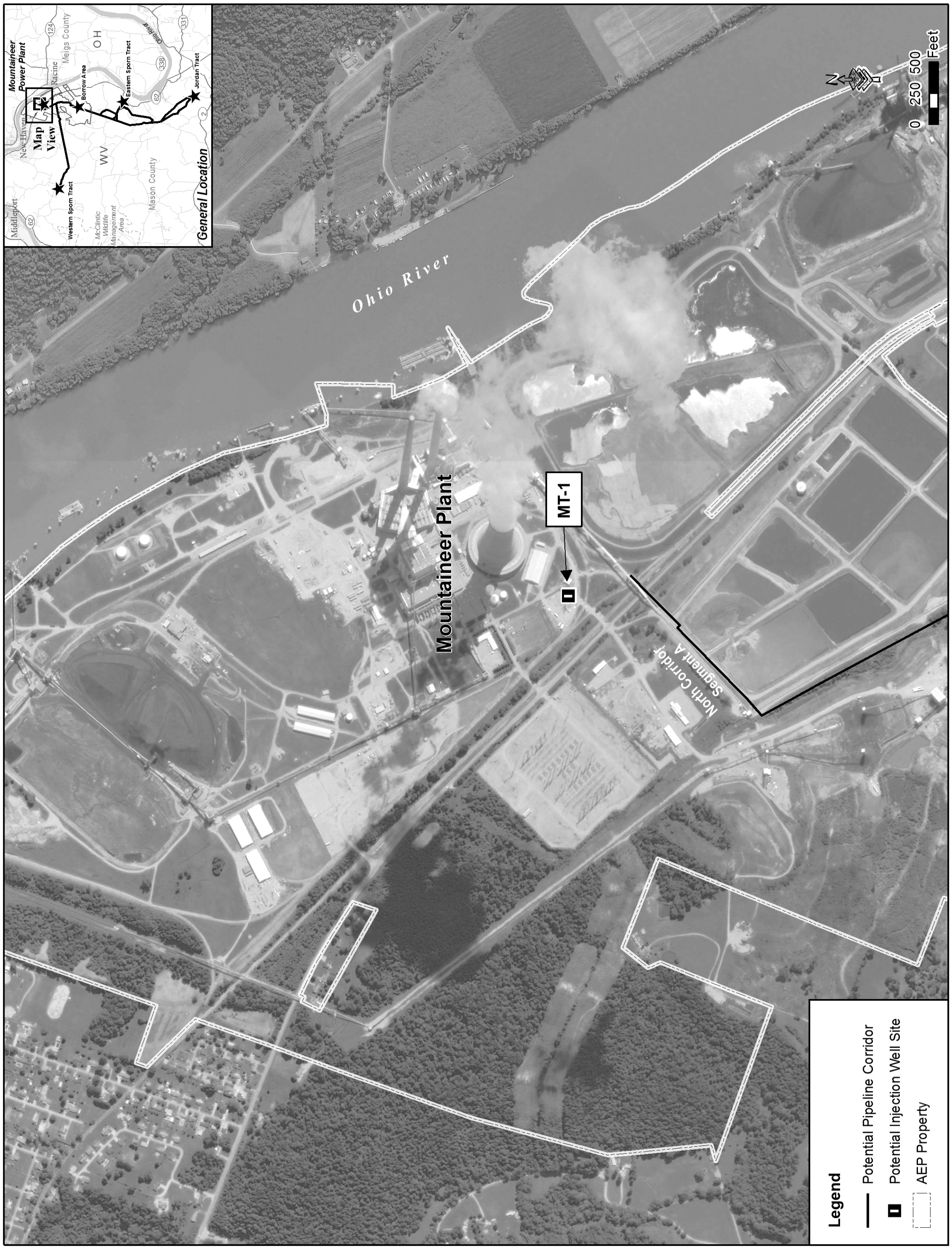

Figure 2-9. Mountaineer Plant

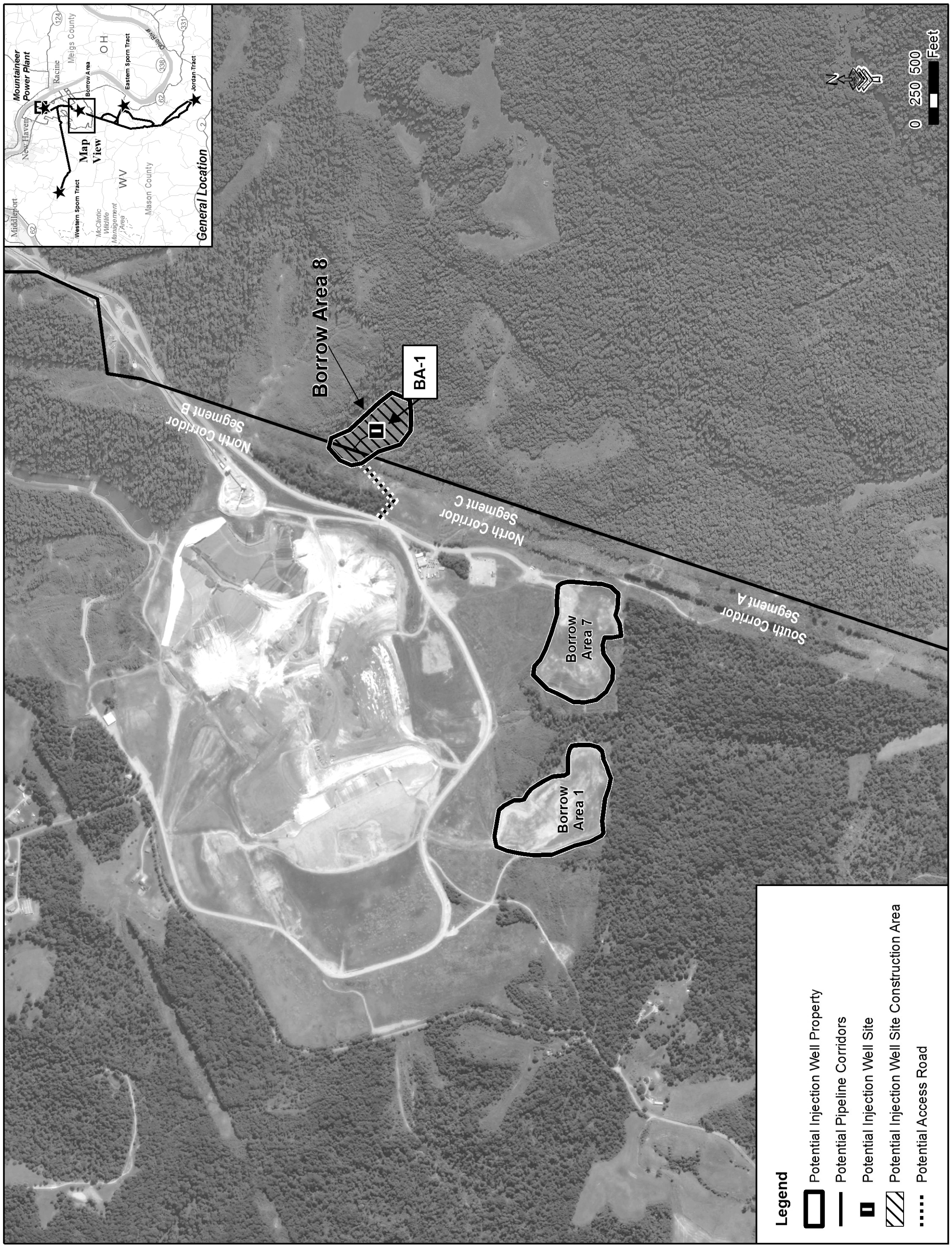

Figure 2-10. Borrow Area

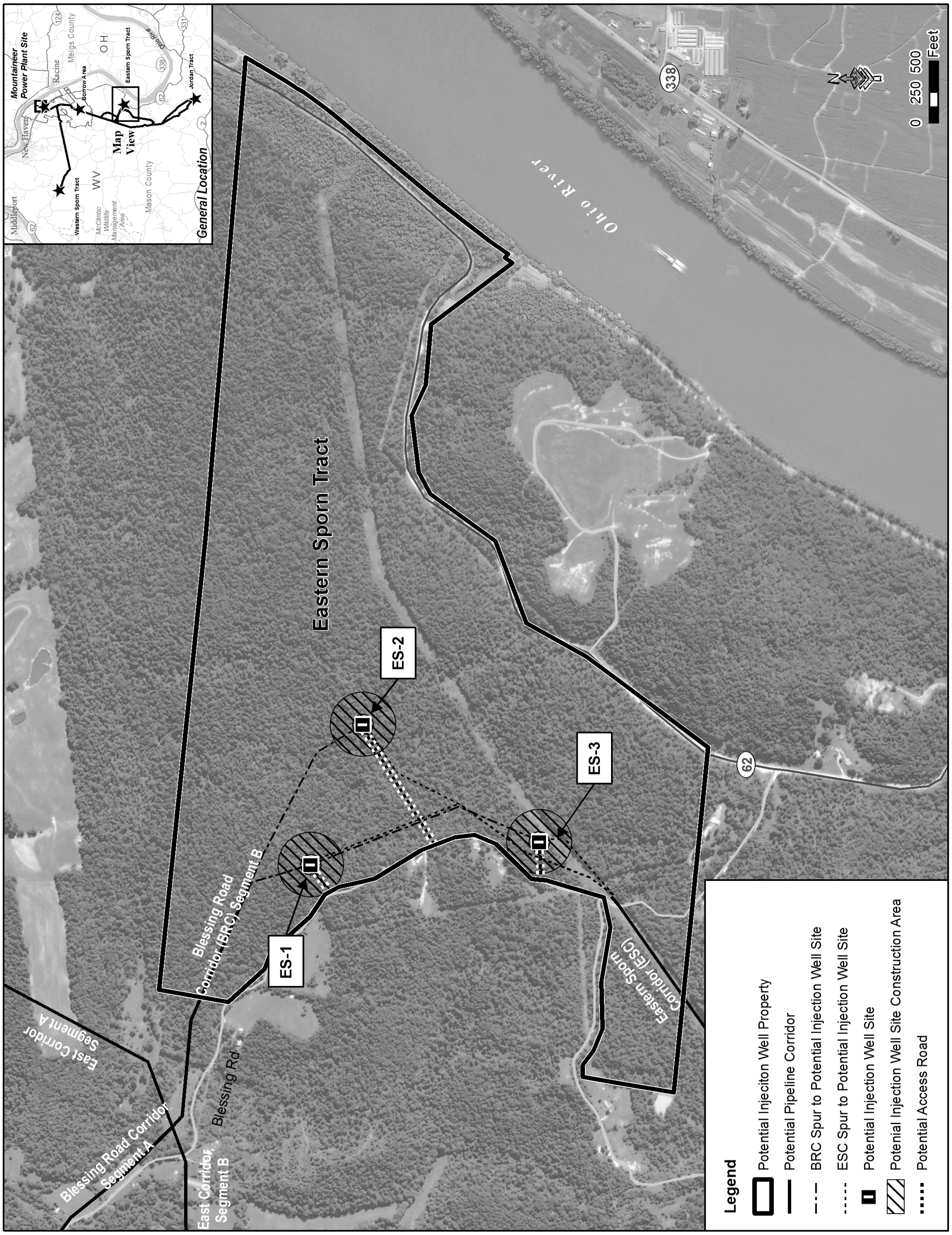

Figure 2-11. Eastern Sporn Tract

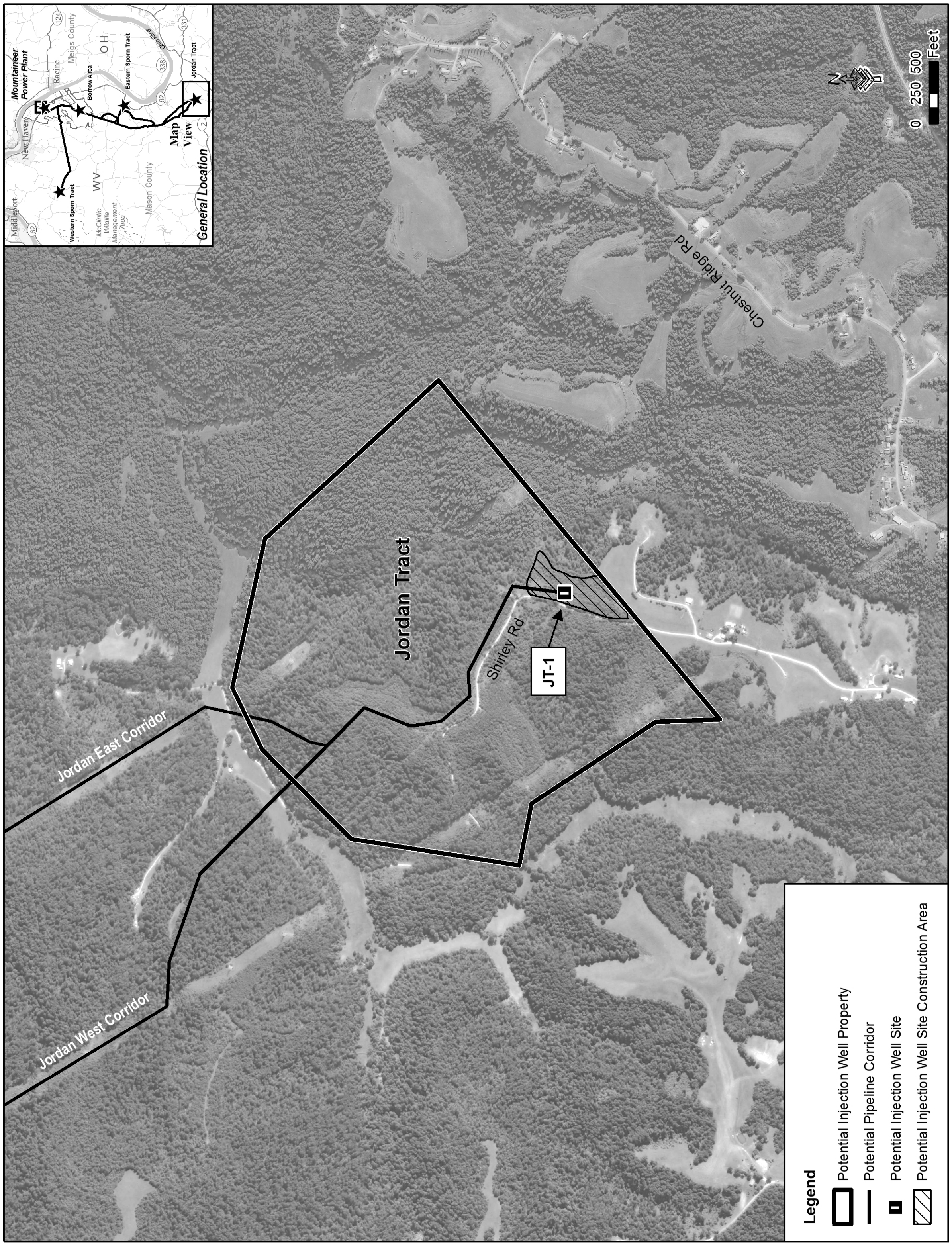

Figure 2-12. Jordan Tract

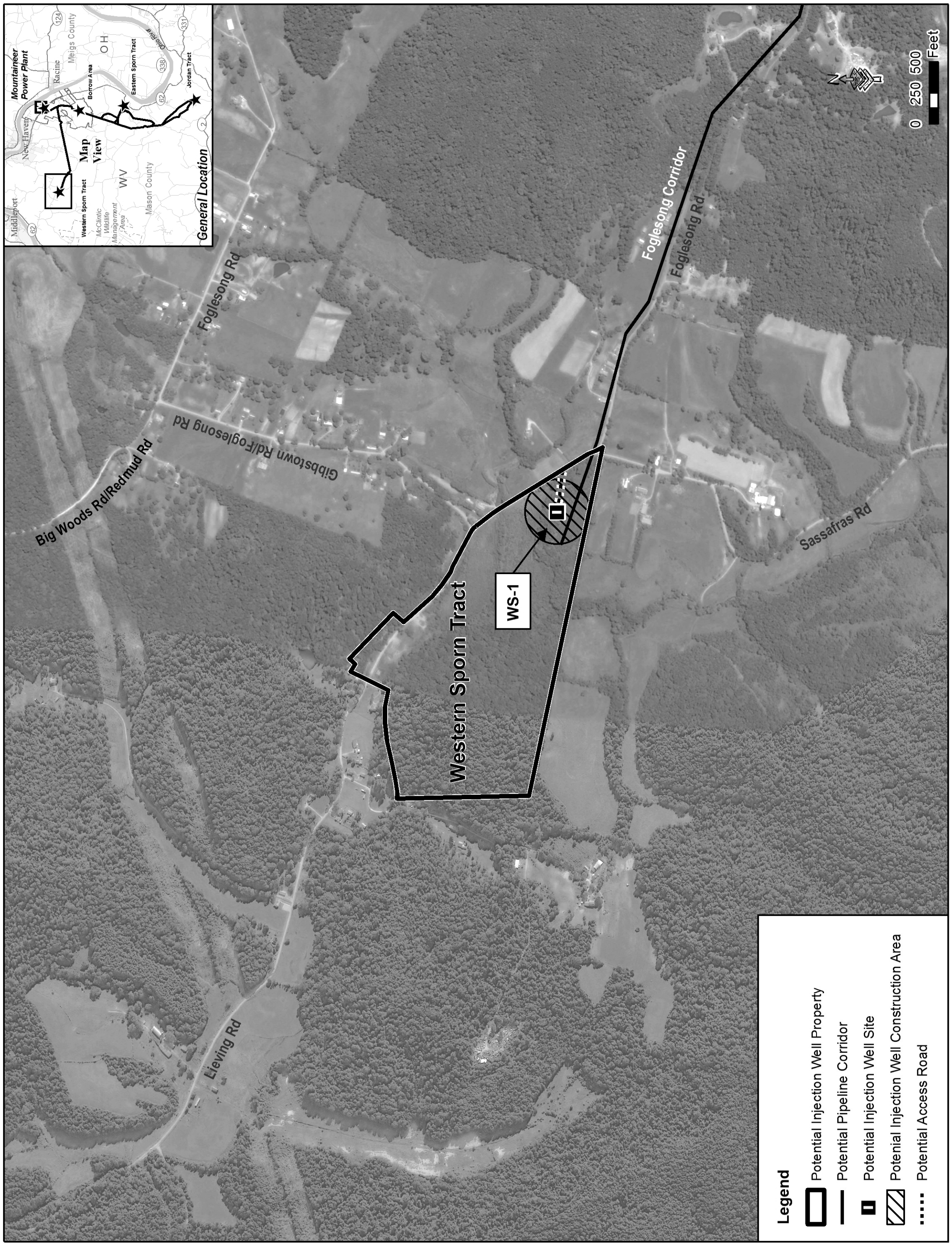

Figure 2-13. Western Sporn Tract

wells would be determined by AEP based on the outcome of geologic assessment activities, including seismic evaluations, characterization wells, and the environmental analysis contained within this EIS.

AEP anticipates that the project would require four to eight injection wells, located in pairs, at two to four different properties. For each pair of wells, AEP expects that one well would inject into the Rose Run Formation and the other well would inject into the underlying Copper Ridge Formation. Final design will be based on the results of the geologic characterization study and subsequent project design and permitting.

AEP identified preferred injection well sites on each of the five properties as shown in Figures 2-9 through 2-13. The preferred injection well sites are labeled as: Mountaineer Plant Injection Well Site MT-1, Borrow Area Injection Well Site BA-1, Jordan Tract Injection Well Site JT-1, Eastern Sporn Tract Injection Well Sites ES-1, ES-2, and ES-3, and Western Sporn Tract Injection Well Site WS-1. AEP selected the preferred sites based on each site's suitability for construction and operation, and based on AEP's siting criteria (see Section 2.3.1). The final location of the injection wells would depend on the results of geologic characterization studies being conducted by AEP to determine the optimal locations and design. If this information becomes available, it would be used to update the data and analyses presented in the Final EIS.

As part of the geologic characterization well studies, AEP plans to initially install geologic characterization wells at the Borrow Area and the Jordan Tract to collect data of both the target injection formations and the overlying caprock. If sufficient data is not obtained from these wells to determine injection well placement and design parameters, then additional characterization wells could be installed at one or all of the remaining three properties. AEP is using the injection data collected at the Mountaineer PVF, data from characterization studies, and a numerical simulation model for analyzing potential injection location suitability. Characterization data would be fed into the model to further refine its accuracy and projected injectivity rates and conditions. From these projections, AEP would determine the number and optimal placement of the injection wells required to handle the CO_2 from the CAP system. Potential impacts resulting from characterization activities are addressed in the cumulative impact analysis, Section 4.2, of this EIS.

2.3.5.2 System Component Overview

The project would store approximately 1.5 million metric tons of CO_2 per year in geologic formations located approximately 1.5 miles below the ground surface. Four to eight injection wells are expected to be needed, each with an estimated injection capacity of 500,000 metric tpy. AEP identified multiple sites on five AEP-owned properties that could be used for siting injection wells. AEP anticipates that each injection well site would have two injection wells to provide flexible injection options, as shown in Figure 2-14. Final design of the number and location of injections wells for the project would be determined based on results of an ongoing geologic characterization study.

It is expected that one well would access the Rose Run Formation (composed primarily of sandstone) and the other would access the Copper Ridge Formation (composed primarily of dolomite). Wells would be approximately 7,500 to 8,500 feet deep. The Rose Run and Copper Ridge Formations are at a much greater depth than groundwater aquifers that are potential sources of drinking water, which are present up to 250 feet below ground surface (bgs).

Once injected into these formations, the CO_2 would be trapped underground by a confining zone which includes impermeable layers of rock known as "caprock." Caprock consists of thick (hundreds or thousands of feet) layers of non-porous rock that act as caps or seals to trap the injected fluid. Caprock has very low permeability–the lack of connected pore spaces that would allow liquid or gas to pass through. The CO_2 injected into these formations might extend to an estimated radius of 3 miles from each injection well site. The geologic characterization study will be used to refine these estimates and support the UIC permitting process.

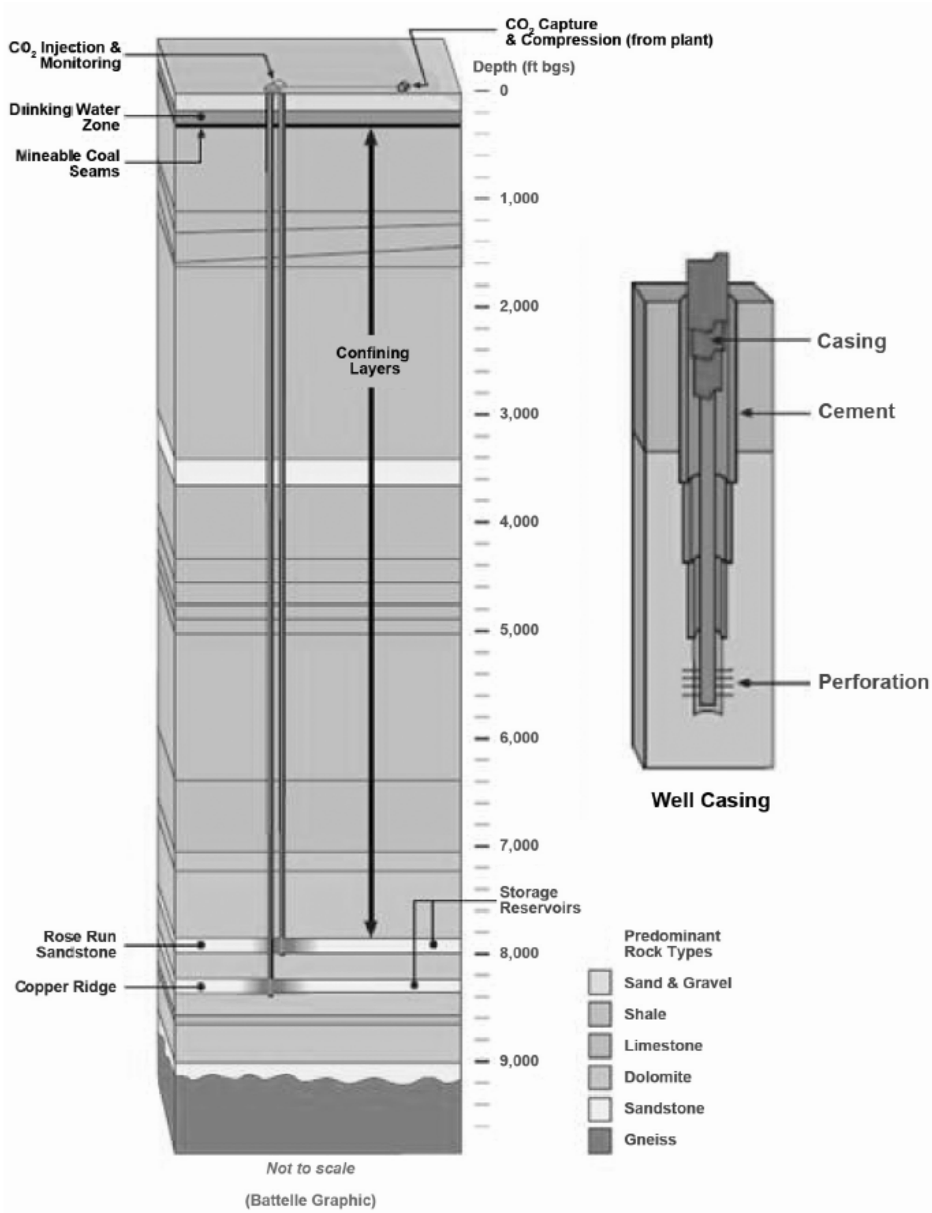

Figure 2-14. Existing Mountaineer Plant PVF Injection Well Cross-Section

On December 10, 2010, the EPA published a final rule, "Federal Requirements Under the UIC Program for CO_2 Geologic Sequestration Wells" (*Federal Register*, Vol. 75, No. 237; the "Class VI rule") (75 FR 43492). Under this rule, the EPA created a new category of injection wells (i.e., Class VI wells) with new federal requirements to regulate the injection of CO_2 for geologic sequestration and ensure the protection of underground sources of drinking water (USDW). The new rule for Class VI wells builds on the program elements currently in place as part of the UIC Program, including siting, area of review, well construction, operation, mechanical integrity testing, monitoring, and well plugging and post-injection site care. West Virginia will have 270 days after the final rule publication to apply for state primacy of the Class VI wells. If West Virginia does not submit an application for primacy within the 270-day deadline, then permits would be issued from the federal UIC Class VI program. Until the West Virginia

Class VI UIC program is approved, West Virginia would issue a permit under the one of the existing classes, with the understanding that the permit would be re-issued as Class VI once primacy is achieved.

Currently, injection of CO_2 is being performed at the Mountaineer Plant PVF in accordance with a Class V experimental wells permit issued by the West Virginia Department of Environmental Protection (WVDEP). The injection wells for the project would be required to obtain a separate UIC permit. New CO_2 injection wells would be permitted as Class V wells until the Class VI proposed regulations are implemented. It is expected that the UIC Permit would also require monitoring wells to be installed (see Section 2.3.6).

2.3.5.3 Construction Phase

The construction of each injection well would be completed in three phases over a period of approximately 4 months:

- Phase 1: Site Preparation (1 month)
- Phase 2: Drilling (2 months)
- Phase 3: Stabilization and Site Restoration (1 month)

The site preparation phase would take approximately 1 month to complete, during which time the site would be cleared of trees and graded; mud pits would be excavated and lined; and access roads would be constructed, as necessary. Trucks would be required to bring fill material for access roadways as necessary, remove debris from the construction sites, and stockpile fill material.

AEP would construct access roads to each injection well from existing, adjacent public roads. Gravel and road base would be used for the access roads, material storage areas, and parking areas. Access roads would have road widths from 12 to 15 feet, with approximate 5-foot drainage ditches on each side. Thus, the total disturbance corridor for each access road would be approximately 25 to 30 feet in width. Figures 2-9 through 2-13 show the potential access roads to each injection well site.

The access roads would be constructed to accommodate trucks up to 40 tons. AEP reviewed existing public roads for the Jordan Tract and Borrow Area sites and concluded that the existing public roads would not require improvement to accommodate drilling rigs and support equipment. Although a formal evaluation has not been completed, it is likely that improvements would be needed to existing roadways leading up to the Eastern Sporn and Western Sporn Tracts to accommodate drilling rigs and support equipment. AEP would coordinate with applicable regulatory agencies (e.g., West Virginia Department of Transportation (WVDOT), local authorities, etc.) to obtain all necessary approvals required to implement the appropriate roadway improvements. Roadway improvements would occur prior to any construction activities at the injection well sites to ensure that the necessary transportation infrastructure is in place to support the number and types of vehicles expected to access the sites during the construction and operation phases.

During construction, each injection well site would require approximately 5 acres to support the construction process. AEP may install semi-permanent fencing around the construction site to control access during drilling operations. As the last step in this phase, the equipment, materials, and temporary infrastructure required to support the drilling operations would be brought onsite. Potable (drinking) water, portable toilets, and hand-wash stations would be provided for use by construction workers at each property.

Figure 2-15 shows a conceptual well construction layout, including typical facilities and equipment that would be required to support drilling operations. This equipment would include the following:

- **Drilling Rig** – a mobile drilling rig with a portable tower derrick (120 to 180 feet in height)
- **Pipe Racks** – temporary structures used to hold (1) drilling pipe before and after use and (2) well casing and tubing before it is installed into the well
- **Storage Sheds** – for equipment and materials storage
- **Office Trailers** – trailers or conex boxes for temporary office space, break areas, or equipment storage areas.
- **Air Compressors** – very large portable air compressors with self-contained diesel-powered generators to supply air to drilling rig
- **Generators** – self-contained portable diesel-powered generators to supply power to construction equipment and facilities as needed

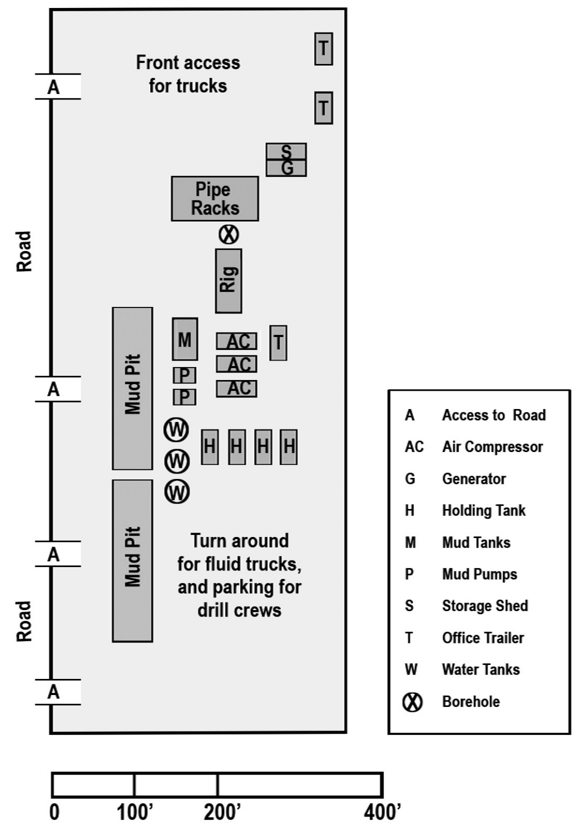

Figure 2-15.

Typical Layout of Well Site during Construction

- **Holding Tanks** – large, tractor-trailer sized storage tanks for temporary storage of drilling fluids or other fluids (i.e., brine, formation fluids, and acid) that are pumped from the well (may also be used for storage of non-potable water or brine to support drilling operations)
- **Water Tank** –for the storage of non-potable water
- **Mud Tanks** –for mixing drilling fluids (drilling mud)
- **Mud Pits** – pits excavated in the ground lined and used for the temporary storage of drilling fluids during drilling operations
- **Mud Pumps** – used to convey drilling fluids from mud tanks to the borehole

Drilling of each injection well would take approximately 2 months and would be conducted on a 24-hour basis. A smaller drilling rig would first be brought onsite to drill the first section of the borehole and set the surface casing to approximately 300 feet below ground. After this is completed, additional site preparation may be required to make way for a larger rig (as shown in Figures 2-16 and 2-17) that would be used to finish the well.

Drilling of the well results in crushed or cut rock (cuttings) that are collected at surface in lined mud pits. The mud pits, as shown in Figure 2-18, are designed so that small rock particles that were not filtered out of the fluid can settle out in the pits. The drilling fluid is then pumped back down the hole and further re-circulated.

Drilling would be completed in intervals as shown in Table 2-11. At each interval, casing of smaller diameter is successively placed within the previous well casing. The casing is installed into the well and cemented in place by pumping cement slurry between the casing and the sides of the borehole. Each well would be designed and constructed to prevent any escapement of stored CO_2. The base of each injection well would use CO_2-resistant cement.

Figure 2-16. Typical Drill Rig with Derrick

Hydraulic fracturing, or stimulation, may be required during injection well construction or during future maintenance of the wells to increase or restore the injectivity of the storage formation. During hydraulic fracturing, a fracturing fluid is pumped into the target formation at a very high pressure, such that the formation begins to crack (i.e., fracture), which allows injected CO_2 to more readily flow through the storage formation. The maximum stimulation pressure would be limited to a value sufficiently below the parting pressure of the adjacent caprock formation, so as to maintain the integrity of the containment system. The evaluation to determine whether hydraulic fracturing would be required would be performed during: (1) the geologic characterization study; (2) later injectivity testing; and/or (3) operational phases. In the event that hydraulic fracturing would be needed, AEP would prepare and submit a detailed plan to the WVDEP for review and approval.

After the well casing has been installed and cemented in place, the final phase of the well construction process (i.e., stabilization and site restoration) would be initiated. The drilling rig and derrick would be dismantled and taken offsite and the well site would be restored. All drilling equipment and infrastructure would be removed from the site, the mud pits would be filled in, and the site would be regraded as necessary. The disturbed soils would be reseeded and restored to pre-construction conditions. In the event that roads are damaged through site construction activities, AEP would perform, if necessary, repairs to return the roadway to its as-found condition.

Figure 2-17. Typical Drill Rig in Transport

Figure 2-18. Lined Mud Pit

Wastes that would be generated from the construction of the injection wells would include drill cuttings and fluids, as well as land clearing waste. AEP anticipates that approximately 120 cubic yards of general solid waste would be generated during the construction of each injection well, which would be properly disposed of in a licensed solid waste landfill.

Drill cuttings and fluids would be placed in the proposed onsite mud pits. Light fluid would be removed (pumped off) from the mud pits into brine trucks and hauled offsite for proper disposal by a licensed service vendor. The drill cuttings would be stabilized prior to disposal offsite. Approximately 350 cubic yards of drill cuttings would be generated during the construction of each injection well.

Soil removed for the construction of the mud pits would be used to regrade the overlying area and to backfill the mud pit excavations. In the event that shallow groundwater is encountered during drilling activities, the groundwater would be directed to mud pits for temporary storage. Any excess water would be hauled offsite for proper disposal by a licensed fluid hauling and disposal vendor. There would be no disposal of groundwater to the surface.

Laborers for the construction of the injection wells would largely be drawn from the pool of workers discussed under Section 2.3.3.3. AEP would provide the construction workers with potable water, portable toilets, and hand-wash stations.

Table 2-11. Typical Injection Well Characteristics

Casing String	Casing Diameter (inches)	Borehole Diameter (inches)	Cemented Interval (feet)	Approximate Set Depth (feet)
Shallow (Coal)	20	24	0 to 300	300
Shallow Intermediate	13 3/8	17 1/2	0 to 2,000	1,800
Intermediate	9 5/8	12 1/4	1,600 to 3,800	3,800
Deep	7	8 3/4	3,300 to 9,100	9,100

2.3.5.4 Operation Phase

Each injection well would require approximately 0.5 acre during operations. This 0.5-acre area would be maintained and kept clear of new tree or shrub growth. In addition, well maintenance activities would occur on an as-needed basis. The following maintenance activities could occur during operation of the proposed injection wells:

- **Well Workover –** Well workovers consist of pulling the tubing out of the well; inspecting the tubing, packer, and downhole assembly on the way out of the well; performing any necessary repairs or downhole modifications; and reassembling the well.
- **Wellhead Maintenance –** Wellhead maintenance includes greasing wellhead valves, replacing seals, and replacing any defective parts.
- **Acidizing –** Certain geologic formations require acidizing. This involves: hauling acid to the site in tanker trucks; pumping acid down the well; pressurizing the well to pump acid into target formations; swabbing the well to draw the spent acid out of the formation; collecting the acid-brine mixture in brine tanker trucks; and hauling the mixture to an appropriate disposal facility.
- **Swabbing –** During swabbing operations, pipe, wireline tools, or rubber-cupped seals are moved within the well to reduce pressure and draw fluids into the well and towards the surface. Fluids pumped from the well (i.e., brine, formation fluids, and potentially acid) are collected in brine tanker trucks by a service vendor and hauled to an appropriate disposal facility.

- **Stimulation –** Stimulation is a method of increasing access to the target formation so that injectivity of CO_2 is increased. Stimulation is typically performed by injecting a fluid under high pressure into the well to create fractures. Other additives may be used to keep the fracture open or to improve surface tension properties.

Wastes generated during the maintenance of injection wells would consist of old parts or seals that have been replaced on various well components. These would be properly disposed of as solid waste. During swabbing and fracturing operations, an acid-brine wastewater mixture would be generated that would be hauled offsite by a service vendor in brine trucks to an appropriate disposal facility. Brine wastewater would not be generated during normal CO_2 sequestration operations (aside from maintenance activities).

2.3.6 CO_2 Storage Monitoring

During the operational life of the Mountaineer CCS II Project, AEP would monitor the CO_2 injection process and storage integrity through the use of monitoring wells and any other methods required by the UIC permit. Monitoring wells of varying depths would be an integral part of the geologic storage monitoring program.

2.3.6.1 Location and Background

Similar to the process used for the design and location of the proposed injection wells, AEP would use data from the geologic characterization study to propose the location and quantity of monitoring wells in their UIC permit application to the WVDEP or EPA as applicable. The siting of these monitoring wells would be largely based on the monitoring objectives of the UIC permit. However, AEP would, to the greatest extent practicable, use the siting criteria identified in Section 2.3.1. Based on the siting criteria, AEP would avoid wetlands, streams, floodplains, sensitive habitats, and cultural resources when installing required monitoring wells. AEP would conduct all required additional field investigations and obtain all required additional permits and agency approvals in the event that monitoring wells would be sited in areas not already considered. Based on preliminary data, AEP anticipates the need for one to three monitoring wells per injection well site, or per co-located pair of injection wells if each monitoring well would sample both geologic target formations. AEP anticipates that monitoring wells would be located within 1,500 to 3,000 feet of the injection well; however, the UIC permit would dictate the final number and siting requirements for monitoring wells.

2.3.6.2 System Component Overview

An important part of the geologic storage program is the MVA that would be used to address regulatory and CCPI Program requirements. The UIC permit, however, would determine the minimum overall monitoring parameters for the proposed CO_2 storage system. Table 2-12 presents the monitoring objectives for the Mountaineer CCS II Project, along with the proposed methods for testing.

> **MVA** is the monitoring, validation, and accounting protocol used to: (1) measure the amount of CO_2 stored at a specific geologic storage site; (2) monitor the site and mitigate the potential for leaks or other deterioration of storage integrity over time; and (3) verify that the CO_2 is being stored successfully and is not harmful to the host ecosystem.

Table 2-12. Monitoring, Verification, and Accounting Options for Injection Wells

Monitoring Objective	Method Summary
Monitor the injection stream for chemical and physical characteristics	Collect periodic samples of CO_2 stream and analyze for composition.
Monitor corrosion of well materials	Monitor corrosion of well materials using coupons in contact with the CO_2 stream.
Monitor the quality of the shallow drinking water aquifer	Monitor groundwater wells completed in the shallow aquifers overlying the injection well site for chemical parameters that are indicators of CO_2 and/or brine presence.
Demonstrate that injection wells have adequate internal mechanical integrity	Conduct annular pressure tests to evaluate internal mechanical integrity of the injection wells.
Demonstrate that injection wells have adequate external mechanical integrity	Conduct temperature surveys or other tests (e.g., tracer survey) to evaluate external mechanical integrity of the injection wells.
Track the extent of CO_2 in the injection zone and monitor the caprock and confining zone	Conduct geophysical monitoring or other monitoring to determine vertical and horizontal position and size of CO_2 plume between injection and monitoring wells.
	Conduct periodic wireline logging to determine the vertical distribution of injected CO_2 adjacent to wells that penetrate the target formation.
	Collect fluid samples from the deep monitoring wells and analyze for parameters that are indicators of CO_2.
	Model CO_2 plume using computational modeling techniques.

CO_2 = carbon dioxide

The final design of the monitoring wells would be subject to the UIC permitting process as addressed in Section 2.3.5.2.

2.3.6.3 Construction Phase

Each monitoring well would be constructed in a similar manner as an injection well. Each monitoring well would likely require up to 5 acres during construction. Refer to Section 2.3.5.3 for details on the construction process.

2.3.6.4 Operation Phase

Monitoring can be divided into three primary types, including: (1) injection system monitoring; (2) confinement monitoring; and (3) CO_2 tracking in the injection zone. The final design of the monitoring program (i.e., to be defined in the project definition phase and the front-end engineering and design) would consider lessons learned from the current ongoing PVF, the monitoring technology assessments conducted under the Midwest Regional Carbon Sequestration Partnership (MRCSP) field projects, guidance from the project's Geologic Experts Advisory Team, and information from other field test programs in the U.S. and abroad.

Injection monitoring includes measurement of the rate, pressure, and temperature of the CO_2 being injected. It would also include monitoring of annulus pressure (i.e., the area between the CO_2 injection tube within the well and the long-string well casing), bottom-hole pressure, and temperature in vicinity of the well to correlate to surface injection pressures and temperatures.

AEP would use a well maintenance and monitoring system, similar to the one developed for the current PVF, to maintain pressure on the annulus fluid in the injection wells so that any potential leaks in the tubing or packer can easily be detected by changes in the annulus pressure. This system would also trigger automatic shutdown of the injection system if certain critical parameters are out of permissible limits (e.g., injection pressure). In addition to continuous monitoring of injection parameters, periodic (e.g., quarterly) sampling and analysis of the CO_2 injection stream would likely be conducted to monitor changes in the physical and chemical characteristics of the injectate. Samples would be obtained at a location in the capture system prior to the final compression stage (i.e., where pressures are low enough that the CO_2 would be in a gas phase, yet where the CO_2 composition is representative of the material that reaches the injection wells).

Confinement monitoring involves verifying the containment of the CO_2 within the injection zone. This would verify the CO_2 is not leaking outside of the confinement system. This would be accomplished using multiple techniques, including possible installation of monitoring wells in the USDW to verify whether the aquifer has actually been impacted by CO_2 or displaced brine.

Mechanical integrity testing, in particular external mechanical integrity tests, provides additional periodic verification of non-leakage along the outside of the wellbore. Carbon dioxide tracking techniques that could be employed (i.e., primarily for CO_2 plume identification and verifying containment within the injection zone) include specialized wireline logging techniques (e.g., pulsed neutron capture) and geophysical monitoring. These techniques are identified in Table 2-12.

Pressure monitoring and fluid sampling are two additional methods that could be employed to help track the distribution and movement of CO_2 in the injection zone. Both of these techniques are being used at the PVF. Analysis of pressure data collected from the PVF injection and monitoring wells would be used to characterize the response to injection. This would enable pressure data collected for the Mountaineer CCS II Project to be more readily and accurately interpreted. In the PVF program, fluid samples from the injection zone monitoring wells are annually collected and analyzed to: (1) evaluate the horizontal spreading of CO_2 at the location of the wells; (2) evaluate variations in CO_2 saturation; and (3) characterize geochemical interactions. In designing the monitoring program for the Mountaineer CCS II Project, AEP would consider fluid sampling techniques that may potentially allow more frequent sampling to be conducted in a cost-effective manner.

AEP does not anticipate atmospheric monitoring or soil gas monitoring as components of the monitoring program because such monitoring would be aimed at detecting CO_2 leakage at the ground surface; therefore, these techniques would not be protective of the USDW. Similarly, monitoring wells placed in the first formation overlying the confining zone would probably not be necessary since the other monitoring techniques that would be deployed are capable of detecting upward migration out of the injection zone.

Computational modeling is yet another CO_2 monitoring, predictive tracking, technique that could be used to support the MVA program. This technique predicts the vertical and horizontal distribution of the injected CO_2 and the extent of the pressure-affected area. Additionally, this is the only technology with the potential to give an indication of the plume growth in three dimensions and all directions. An extensive amount of modeling work has already been conducted for the PVF using the STOMP-CO_2 (PNNL, 2010) simulator to define the area of review, evaluate target formation injectivity, design injection scenarios, and predict CO_2 plume size. Additional modeling simulations could be performed once injection begins to allow the model to be calibrated with actual monitoring data collected during the active injection phase.

Each monitoring well would require 0.5 acre during operations. The final design of the MVA program would be defined by the UIC permitting process as addressed in Section 2.3.5.2.

2.3.7 Decommissioning

The project would be designed for 20 years of operation. AEP would develop a closure plan prior to decommissioning. The removal of the project facilities from service, or decommissioning, may range from "mothballing" to the removal of all equipment and facilities, depending on the conditions at the time. AEP would provide the closure plan to applicable regulators (as required) for review and approval.

The process would involve decommissioning all surface facilities, including connections between the Mountaineer Plant and the injection wells. All exposed pipes, along with other surface facilities, would be decommissioned and may be removed during site closure. AEP would plug and abandon all wells drilled for injection or monitoring in accordance with federal and state regulations; however, some monitoring wells may be required to remain in place to support post-injection monitoring activities.

AEP would conduct post-injection monitoring activities in accordance with applicable UIC regulations and permit conditions. The UIC program is evolving to specifically address geologic storage and its long-term safety (see Section 2.3.5.2). At this time, it is difficult to predict the types and frequency of post-operational monitoring and testing that may be required in the future. Both AEP and DOE also acknowledge the need for continued monitoring of the sequestered CO_2 during a period after injection ceases. AEP would apply a variety of monitoring techniques as described in Section 2.3.6. Implementation of appropriate monitoring techniques is a key factor for validating the successful geologic storage of CO_2.

2.3.8 Measures to Reduce Potential Impacts

This section presents some of the general measures that would be implemented to reduce potential impacts. Section 4.3, Mitigation of Impacts, includes a detailed resource-specific list of all BMPs and mitigation measures that have been proposed for the construction and operation of the project.

2.3.8.1 Stormwater Pollution Prevention

AEP would develop and implement erosion control methods and stormwater management plans to ensure compliance with the state's enforcement of the federal Clean Water Act (CWA) and applicable state standards. In addition, a stormwater construction permit would be obtained from the WVDEP to minimize potential impacts from stormwater. Preventative methods employed would be based on the terrain and soil characteristics of the work area. Typical methods include use of silt fences, hay bales, stabilization mats, crushed rock and stone, ditch plugs, diversion terraces, and retention ponds.

In accordance with 40 CFR 122.26, a project-specific construction Stormwater Pollution Prevention Plan (SWPPP) would be developed. The SWPPP would identify BMPs for erosion prevention and sedimentation control that would be implemented during construction. The SWPPP would include a description of construction activities and address, identify, and provide the following:

- Potential for discharging sediment and other potential pollutants from the site
- Locations and types of all temporary and permanent erosion prevention and sediment control BMPs, along with procedures to be used to establish additional temporary BMPs as necessary for the site conditions during construction
- Site map with existing and final grades, including dividing lines and direction of flow for all pre- and post-construction stormwater runoff drainage areas located within the project limits. The site map must also identify impervious surfaces and soil types
- Locations of areas not to be disturbed
- Locations of areas where construction would be phased to minimize duration of exposed soil areas
- Identification of surface waters and wetlands that could be affected by stormwater runoff from the construction site
- Methods to be used for final stabilization of all exposed soil areas

2.3.8.2 Noise and Light Control

Noise control measures that may be incorporated (as necessary) into the CAP facility design include: locating and orienting plant equipment to minimize sound emissions; providing buffer zones; enclosing noise sources within buildings; and including silencers on plant vents and relief valves. Potential noise associated with construction of the capture, transport, and well sites would be controlled in accordance with all regulatory requirements.

Lighting installed at the CAP facility and injection wells would be designed to reduce potential light and glare beyond the site boundary. All high-intensity lighting would be shielded. Exterior lighting for some areas would be designed to switch off when not in use, where such lighting is not necessary for security and safety.

2.4 CONSIDERATION OF ACTIONS IN THE EIS

2.4.1 Project Implementation Scenarios

The specific manner in which AEP would ultimately implement the project depends on a combination of factors. These factors include, but are not limited to, the results of geologic characterization study, pipeline routing constraints, UIC permitting conditions, and various cost factors. To assess the potential range of impacts that could occur from implementation of the project, several scenarios for proposed project implementation have been considered in this EIS (see Table 2-13). These scenarios present combinations of pipeline corridors and injection well properties that are representative of a reasonable range of options that could be implemented. These are not intended to provide an exhaustive list of options, but rather to bracket the range of available options and illustrate reasonable and plausible combinations.

DOE evaluated each of the scenarios listed in Table 2-13 in this EIS to assess the range of potential impacts that could occur and to properly bound the impact analysis. Assuming geologic characteristics are favorable at all locations, Scenario A would be AEP's preferred scenario and Scenario C would be AEP's least preferred scenario. This preference is based largely on cost, effort to implement, and environmental considerations. Scenario A would minimize these elements; Scenario C would maximize them. As such, Scenario C is the least preferable and considered to be the upper bound or "worst case" from an impact perspective because it would involve the greatest length of pipelines, the greatest number of required injection wells, and the greatest number of properties involved with the project. The number of injection wells on any one site would be based on the final design. It is possible that more than two wells would be required on one site; however, AEP does not anticipate that the total number of wells required for the project would exceed eight (upper bound).

Section 4.1 of this EIS summarizes and compares the potential impacts of the No Action Alternative and the three project implementation scenarios. The baseline conditions that are relevant to the No Action Alternative are described in Chapter 3 for each resource area. The potential impacts to each environmental resource area under the No Action Alternative and the Proposed Action are analyzed in depth in Chapter 3.

2.4.2 The Mountaineer CCS II Project and Connected Actions

This EIS analyzes the impacts of all components of the project, including those described in Section 2.3, as connected actions in accordance with NEPA (40 CFR 1508.25(a)(1)), regardless of the entity responsible for construction and operation of the specific component. A connected action is one that is closely related to the project, including an action that automatically triggers another action that may require an EIS; an action that cannot or would not proceed unless another action is taken previously or simultaneously; or an action that is an interdependent part of a larger action and depends on the larger action for its justification. Besides the connected actions associated with utilities (e.g., a new WWTP), monitoring wells, and access roads described in Section 2.3, no other connected actions regarding the project have been identified.

Table 2-13. Proposed Project Implementation Scenarios

Injection Well Property	Alternative Route	Scenario A "Lower Bound"	Scenario B	Scenario C "Upper Bound"
		Number of Injection Wells per Property		
Mountaineer Plant (MT-1 Location)	Plant Routing	2	0	0
Borrow Area	Borrow Area Route	2	2	2
Eastern Sporn Tract	Eastern Sporn Route 1	0	2	2
	Eastern Sporn Route 2			
	Eastern Sporn Route 3			
	Eastern Sporn Route 4			
Jordan Tract	Jordan Route 1	0	2	2
	Jordan Route 2			
	Jordan Route 3			
	Jordan Route 4			
Western Sporn Tract	Western Sporn Route	0	0	2

Note: These scenarios present combinations of pipeline routes and injection well properties that are representative of a reasonable range of options that could be implemented. Scenario A represents the lower bound (least wells and shortest pipeline) for impacts related to the number of wells and length of pipeline, while Scenario C represents an upper bound (most wells and longest pipeline). These are not intended to provide an exhaustive list of options, but rather to bracket the range of available options and illustrate reasonable and plausible combinations.

2.4.3 Amine-Based Capture System Feasibility Study

In order to evaluate potential impacts associated with the consideration of an amine-based CO_2 capture technology as a preliminary project option, DOE identified impacts in the DEIS typically associated with amine-based capture technologies. For the purpose of supporting this impact analysis of the preliminary project option, DOE assumed that the area required to construct an amine-based system would be less than or equal to that identified for the proposed technology. Adverse impacts associated with amine-based capture technologies are presented in Chapter 3 only for the resource areas in which it is expected that the impacts would be different from those identified for the proposed technology.

2.4.4 Cumulative Impacts

This EIS addresses the impacts of the project incrementally when added to the impacts of other past, present, and planned or reasonably foreseeable future projects within the geographic area. The evaluation of cumulative impacts was developed in accordance with the cumulative impact analysis requirements of CEQ Regulations (40 CFR 1508.7). See Section 4.2, Potential Cumulative Impacts, for further information.