Mountaineer Commercial Scale
Carbon Capture and Storage Project

Topical Report:
Preliminary Public Design Report

Reporting Period: 2/01/10- 9/30/11

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Issued: December 14, 2011

DOE Award No.: DE-FE0002673
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Disclaimer

Abstract

This Preliminary Public Design Report consolidates for public use nonproprietary design information on the Mountaineer Commercial Scale Carbon Capture & Storage project. The report is based on the preliminary design information developed during the Phase I – Project Definition Phase, spanning the time period of February 1, 2010 through September 30, 2011. The report includes descriptions and/or discussions for:

- DOE's Clean Coal Power Initiative, overall project & Phase I objectives, and the historical evolution of DOE and American Electric Power (AEP) sponsored projects leading to the current project;
- Alstom's Chilled Ammonia Process (CAP) carbon capture retrofit technology and the carbon storage and monitoring system;
- AEP's retrofit approach in terms of plant operational and integration philosophy;
- The process island equipment and balance of plant systems for the CAP technology;
- The carbon storage system, addressing injection wells, monitoring wells, system monitoring and controls logic philosophy;
- Overall project estimate that includes the overnight cost estimate, cost escalation for future year expenditures, and major project risks that factored into the development of the risk based contingency; and
- AEP's decision to suspend further work on the project at the end of Phase I, notwithstanding its assessment that the Alstom CAP technology is ready for commercial demonstration at the intended scale.

Acknowledgement

The author would like to thank all who contributed to this report, both directly and indirectly (via incorporation of select content from various work products). Those individuals include everyone on the project teams at AEP, Alstom, Battelle, and WorleyParsons. The level of cooperation, dedication, effort and expertise during the Phase I Project Definition Phase was exceptional and a testament to what can be accomplished by an extended project team working to compliment the efforts of each other in a manner that respects and acknowledges the inputs of all parties.

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Executive Summary

This Public Design Report provides non-proprietary design information from the Phase I - Project Definition work products associated with the Carbon Capture and Storage system planned for installation at Appalachian Power Company's Mountaineer Plant, located in New Haven, West Virginia, under U.S. Department of Energy Cooperative Agreement No. DE-FE002673.

The overall objective of the project is to design, build and operate a commercial scale carbon capture and storage (CCS) system capable of treating a nominal 235 MWe slip stream of flue gas from the outlet duct of the Flue Gas Desulfurization system. The project was planned for execution in four phases: Phase I - Project Definition (February 2010 – September 2011), Phase II - Design & Permitting (October 2011 – December 2012), Phase III – Construction & Start-up (January 2013 – August 2015), and Phase IV – Operations (September 2015 – June 2019). AEP and its integrated project team successfully completed Phase I objectives, as outlined in the cooperative agreement, calling for:

- The resolution of outstanding conditions with the U.S. Department of Energy (DOE) cooperative agreement,
- Project specific developmental activities (front-end engineering and design),
- The initiation of the NEPA process, and
- The identification of exceptionally long lead time items.

The front-end engineering and design package incorporated knowledge gained and lessons learned (construction and operations related) from the Mountaineer Product Validation Facility and the design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

Based on the work completed in the front-end engineering and design package, the project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Issued preliminary PFDs and overall mass and energy balances,
- Drilled a deep well for characterization of subsurface geology at one of the alternative CO_2 storage sites,
- Completed preliminary project design, and
- Submitted a decision point application regarding future project plans.

The project identified many significant findings through the course of the Phase I studies, investigations, and conceptual design. Prime examples related to carbon capture and storage include, among others, the realization that carbon capture technology is basically a chemical facility retrofit and that a power plant and chemical plant have different operating philosophies; the integration of those philosophies not only drive process efficiency, but also process complexity. On the storage side, we confirmed that the Lower Copper Ridge formation, identified through previous pilot project efforts, is a suitable storage reservoir in the Mountaineer area through analysis of regional data as well as data obtained from the Borrow Area characterization well (BA-02). Additionally, the project team successfully completed the conceptual design of a commercial scale CCS facility, capable of capturing 90% of the CO_2 from the flue gas stream and sequestering 1.5 million metric tons of CO_2, per year in deep saline reservoirs.

The work completed during Phase I also provides AEP and the DOE with a good understanding of the project's overall cost and risks for: Phase II Detailed Engineering/Design & Permitting, Phase III Construction & Start-up, and Phase IV Operations. As shown in Table ES-1 below, the $825-million overnight cost estimate includes: engineering, procurement, construction, start-up and fine tuning of the carbon capture and storage system retrofits. The $896-million figure includes an expected $71-million of escalation to account for the time value of money as-spent over the project life. Additionally, the project performed a risk based evaluation of the cost estimate, and determined a need to add up to $103-million to the estimate to insure that adequate funding is reserved for the overall project. The total project cost includes an estimated $66-million associated with Phase IV operations over a planned four year DOE project operating life, spanning September 2015 through June 2019. The $1.065-billion total project cost represents an approximate 99.5% level of confidence that the project will meet or under run that amount. The total project is expected to have an estimate at completion (Phases I – IV) within the range of $962-million to $1.065-billion.

System (Phases I, II & III)	Estimate ($ x million)
Capture System	$665
Storage System	$160
Sub-Total (Overnight Cost)	**$825**
Escalation	$71
Sub-Total (As Spent)	**$896**
Risk Based Contingency	$103
Total Constructed Cost	**$999**
Phase IV Operations	$66
Total Project Cost	**$1,065**

Table ES-1 – Upper Limit Project Cost, Includes Four Years of Operations

The largest risks to the project, accounted for within the $103-million risk based contingency, lie in the uncertainty associated with permitting and installation of the CO_2 storage system, followed by the volatility of projected escalation, and potential labor overtime.

As the project was drawing near to the end of Phase I, AEP communicated to the DOE its plans to dissolve the existing cooperative agreement and postpone project activities following the completion of Phase I. At the time of the communication, AEP noted that when the original grant application was submitted by AEP in response to DE-FOA-0000042, AEP believed it important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations concerning CO_2 emissions at its coal-fired power plants. Various bills in Congress were introduced to limit emissions but also provide funding for early CCS projects. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP's cost share of the Mountaineer Commercial Scale Project.

Notwithstanding AEP's decision, the work completed in Phase I continues to support AEP's belief that the Alstom Chilled Ammonia Process technology is ready for commercial demonstration of carbon capture at the intended scale. AEP believes that the completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere in the U.S.

1.0 Introduction

1.1 Purpose of the Public Design Report

This Public Design Report is to provide non-proprietary design information from the Phase I - Project Definition work products associated with the Carbon Capture and Storage system planned for installation at Appalachian Power Company's Mountaineer Plant, located in New Haven, West Virginia, under U.S. Department of Energy Cooperative Agreement No. DE-FE002673. Appalachian Power Company is a subsidiary operating company of American Electric Power (AEP). This report was prepared by American Electric Power Service Corporation on behalf of Appalachian Power Company.

1.2 Project Overview

1.2.1 Clean Coal Power Initiative

The Mountaineer Commercial Scale Carbon Capture and Storage Project described in this report is being conducted under Round Three of the Department of Energy's (DOE) Clean Coal Power Initiative (CCPI). The CCPI is a cost-shared collaboration between the Government and industry to increase investment in low-emission coal technology by demonstrating advanced coal based, power generation technologies, consistent with the Energy Policy Act of 2005. The CCPI goal is to accelerate the readiness of advanced coal technologies for commercial deployment, thus ensuring that the United States has clean, reliable, and affordable electricity and power. By overcoming technical risks associated with bringing advanced technology to the point of commercial readiness, the CCPI accelerates the deployment of new coal technologies for power and hydrogen production and, contributes to proving the feasibility of CO_2 management integration. CCPI also facilitates the movement of technologies into the marketplace that are emerging from core research and development activities.

Initiated in 2002, the CCPI is a multi-year program that builds upon the advancements made by previous and continuing clean coal research to accelerate the readiness of advanced coal technologies for commercial deployment, ensuring that the United States has clean, reliable, and affordable electricity and power. Round Three of the CCPI sought cooperative agreements between the Government and industry to demonstrate, at commercial scale new technologies that capture carbon dioxide emissions from coal-fired power plants and either sequester the CO_2 or put it to beneficial use. The goals are to demonstrate at commercial scale in a commercial setting, technologies that (1) can achieve a minimum of 50% CO_2 capture efficiency and make progress toward a target CO_2 capture efficiency of 90% in a gas stream containing at least 10% CO_2 by volume, (2) make progress toward capture and sequestration goal of less than 10% increase in the cost of electricity (COE) for gasification systems and less than 35% for combustion and oxycombustion systems all as compared to current (2008) practice, and (3) capture and sequester or put to beneficial use a minimum of 300,000 tons per year of CO_2 emissions.

1.2.2 Over all Project Objectives

As identified in the Cooperative Agreement DE-FE0002673, AEP's objective of the Mountaineer Commercial Scale Carbon Capture and Storage Project (MT CCS II) project is to design, build and operate a commercial scale carbon capture and storage (CCS) system capable of treating a nominal 235 MWe slip stream of flue gas from the outlet duct of the Flue Gas Desulfurization (FGD) system at the AEP's Mountaineer Power Plant (Mountaineer Plant), a 1300 MWe coal-fired generating station located in New Haven, WV. The CCS system is designed to capture 90% of the CO_2 from the incoming flue gas using the Alstom Chilled Ammonia Process (CAP) and compress, transport, inject and store 1.5 million tonnes per year of the captured CO_2 into deep saline reservoirs.

Specific Project Objectives include:

1. Achieve a minimum of 90% carbon capture efficiency during steady-state operations.
2. Demonstrate progress toward capture and storage at less than a 35% increase in cost of electricity (COE).
3. Store CO_2 at a rate of 1.5 million tonnes per year in deep saline reservoirs.
4. Demonstrate commercial technology readiness of the integrated CO_2 capture and storage system.

1.2.3 Phase I Objectives

AEP's Phase I activities and deliverables, as outlined in Cooperative Agreement DE-FE0002673 are noted, "*Phase I – Project Definition includes resolution of outstanding conditions with the U.S. Department of Energy (DOE) cooperative agreement, project specific developmental activities (i.e., front-end engineering and design), initiation of the NEPA process, and identification of exceptionally long lead time items. The front-end engineering and design package will incorporate knowledge gained and lessons learned (construction and operations related) from the Mountaineer Product Validation Facility (PVF). The front-end engineering and design package is also expected to establish the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.*

During Phase I (Project Definition), AEP will complete the following key milestones:

- *+ / - 25% Cost Estimate Complete*
- *Project Design Basis Complete*
- *Detailed Phase II Project Schedule Developed*
- *Provide DOE with all information it needs to complete the NEPA process*
- *Select Prime Construction Contractor(s)*
- *Issue Preliminary PFD and Overall Mass and Energy Balance*

- *Complete FEED*
- *Submit Phase I Decision Point Application*"

1.2.4 Mountaineer Plant Site Information

The Mountaineer Plant is located along the Ohio River in New Haven, West Virginia.

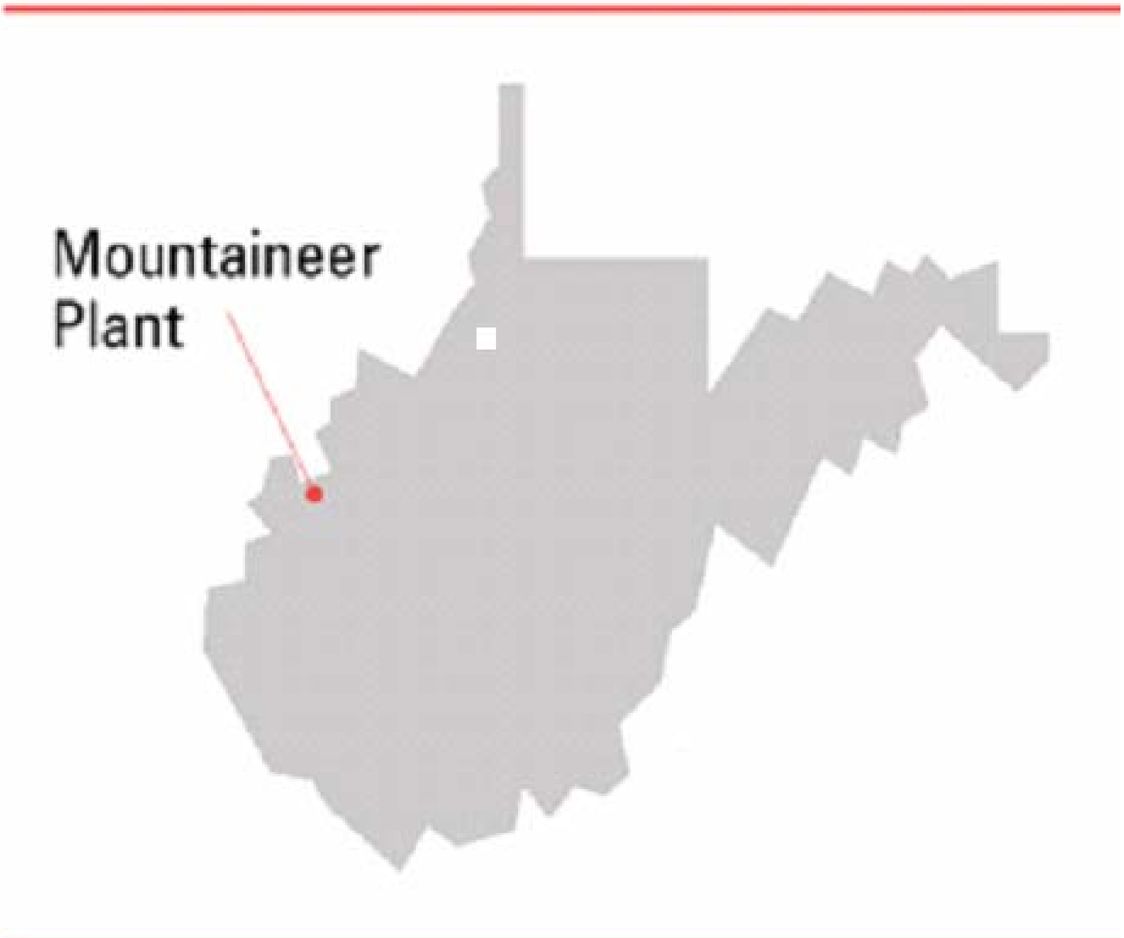


Figure 1 - Location Map for Mountaineer Plant, New Haven, WV

The 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) and rail. The plant is equipped with air emissions control equipment, which includes: (1) an electrostatic precipitator (ESP) for particulate control; (2) selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control; (3) a wet flue gas desulfurization (WFGD) unit for sulfur dioxide (SO_2) control; and (4) a Trona injection system for sulfur trioxide (SO_3) control.

1.2.5 Historical Evolution to Current Project

AEP has been actively involved in the development of CCS technology over the past eight years. AEP's initial involvement in the development of CCS began in 2003 with the Ohio River Valley CO_2 Storage Project. DOE's National Energy Technology Laboratory (NETL) sponsored the project under Contract No. DE-AC26-98FT40418. The project included the drilling, sampling, and testing of a deep well combined with a 2D seismic survey to characterize local and regional geologic features at AEP's Mountaineer plant. The project provided an evaluation of deep rock formations and led to the development of practical maps, data, and characterization of some of the issues that needed to be considered for CO_2 storage projects in the Ohio River Valley. Site characterization information was also used to feed into a systematic design feasibility assessment for a first-of-a-kind (FOAK) integrated capture and storage facility at an existing coal-fired power plant in the Ohio River Valley region, an area with a large concentration of power plants and other emission sources. Subsurface characterization data were used for reservoir simulations and understanding of issues relating to injection, monitoring, strategy, risk assessment, and regulatory permitting.

In March 2007, AEP signed an agreement with Alstom to further demonstrate the CAP technology via scale up to a 20-MWe Product Validation Facility (PVF). Alstom had previously constructed and operated a 1.7-MWe pilot scale CAP capture facility at the We Energies Pleasant Prairie Power Plant. The flue gas volume of the slip stream for the PVF is equivalent to the flue gas generated from a 20 MW coal fired power plant. The PVF was designed to capture and store approximately 100,000 metric tons of CO_2 annually. The PVF also included CO_2 storage, building upon the $7 million investment by DOE/NETL into the Ohio River Valley CO_2 Storage Project, which laid the groundwork for site selection of the PVF based on its very detailed geologic characterization study.

Captured CO_2 from the PVF was injected via two onsite wells into two geologic formations (Rose Run sandstone and Copper Ridge dolomite) located approximately 1.5 miles below the plant site. One injection well and three deep monitoring wells were drilled within the power plant property between 2008 and 2009. The characterization well, previously drilled in 2003 under the DOE Contract No. DE-AC26-98FT40418, was re-worked and transformed into a second injection well. The PVF provided critical data to support the design and engineering of the MT CCS II project.

In August 2009, AEP submitted an application to DOE to demonstrate the commercial viability for retrofitting the Mountaineer plant with a 235-MWe nominal carbon capture and storage facility, building on the work of the DOE supported Ohio River Valley CO_2 Storage Project, and including the non-DOE funded PVF. In December 2009, DOE announced the selection of the Mountaineer Commercial Scale Carbon Capture and Storage Project for funding under Round Three of the DOE's CCPI.

2.0 Plant Retrofit Technology Overview

2.1 Overview of Capture and Storage Systems

The CO_2 capture system proposed for the MT CCS II project is similar to the Alstom CAP system utilized at the Mountaineer Plant PVF, but about 12 times the scale. The proposed facility is expected 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-MWe net (260-MWe gross) scale facility. As with the PVF, the process uses an ammonia-based reagent to capture CO_2 and isolate it in a form suitable for geologic storage. The captured CO_2 stream is cooled and compressed to a supercritical state for pipeline transport to injection well sites located as far as 12 miles (approx. 19 kilometers) from the plant. In general terms, supercritical CO_2 exhibits properties of both a gas and a liquid.

2.1.1 Chilled Ammonia System

The CAP uses an ammonia-based reagent to remove CO_2 from the flue gas. With reference to Figure 2, the first step in the process is to cool the flue gas with chilled water 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 is then pumped to a regeneration vessel. In the regeneration vessel, the solution is heated under pressure with steam from the power plant, and the reactions are reversed, resulting in a high-purity stream of CO_2. The regenerated reagent is then recycled back to the absorption vessel to repeat the process. The CO_2 stream is scrubbed to remove excess ammonia, then compressed, and transported via pipeline to injection wells.

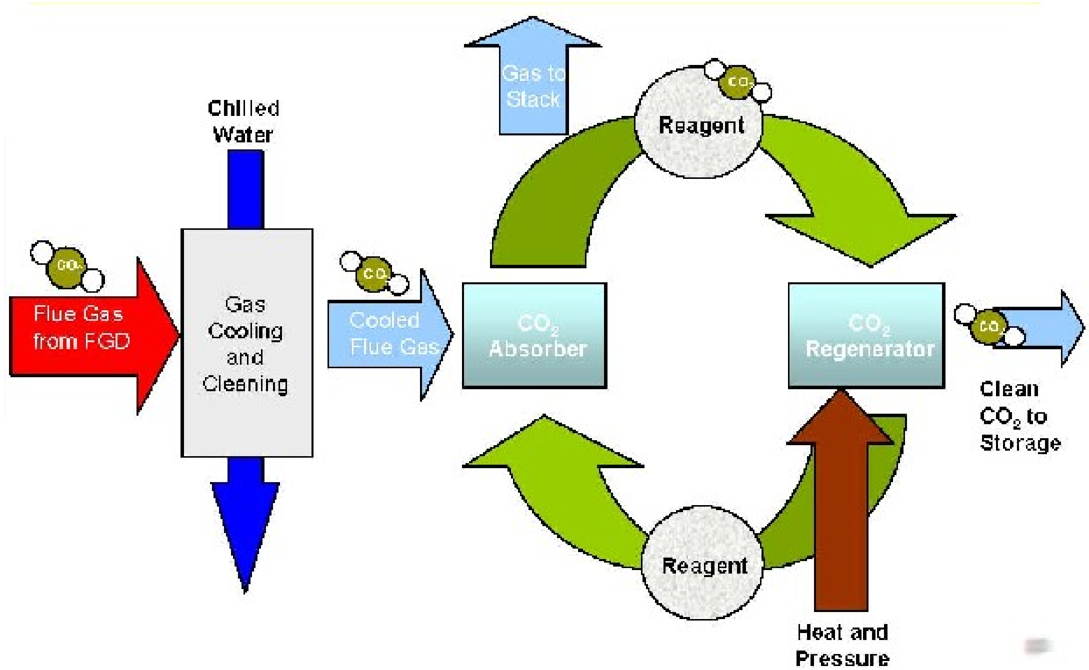


Figure 2 - Depiction of Chilled Ammonia Process

2.1.2 Storage System

The high-purity (>99.5%) stream of CO_2 exiting the CAP is compressed to either a subcritical or supercritical condition followed by cooling and pumping to the final CO_2 pipeline pressure for transport to two planned injection wells. CO_2 injection is targeted to for the Copper Ridge geological formation, over 1.5 miles below ground surface. Injection pressures in the 1200 psi – 1500 psi range are expected early in the life of the injection wells, based on operating experience with the PVF. The maximum expected injection pressure is approximately 3000 psi.

The specific testing and monitoring requirements for the commercial-scale project are not known at this time because an Underground Injection Control (UIC) permit has not yet been issued for the project. The current planned injection and monitoring system for the MT CCS II project is however based on experience with previous deep wells and the injection system that was operated for 18 months at the PVF. The current planned system for MT CCS II is comprised of two injections wells, four intermediate and nine deep monitoring wells, and eight groundwater monitoring wells. The injection and monitoring wells for the MT CCS II project are designed for the injection and monitoring of the CO_2 plume and pressure front during and after injection. Proper well design and use of appropriate injection equipment, monitoring tools, and sampling equipment protects the underground sources of drinking water (USDW) from contamination during drilling and operation of the wells.

The U.S. EPA, in December 2010, issued the Geologic Sequestration (GS) Rule, which establishes a new class of injection well, Class VI, for wells that will be used to inject CO_2 into deep geologic formations for long-term storage (sequestration). The GS rule sets minimum federal technical criteria for Class VI wells for the purpose of protecting USDWs and mandates comprehensive monitoring of all aspects of well integrity, CO_2 injection and storage, and groundwater quality during the injection, operation, and post-injection periods. A Class VI UIC permit will be sought for the commercial-scale project; therefore, testing and monitoring requirements in the new GS Rule were considered in developing the testing and monitoring plan.

3.0 Retrofit Approach

Prior to a discussion of the various system designs, it is important to understand AEP's approach to retrofit integration and the philosophy on which technical and design basis decisions were made.

The chilled ammonia process for CO_2 capture, like other post-combustion CO_2 capture technologies, is a complex chemical process with a certain energy demand. As such, the power plant, operating with CO_2 capture capabilities, resembles a chemical plant with process equipment (e.g. regenerating columns, packed absorber columns, stripping equipment, etc). Much of this equipment, while not dramatically different in scale or appearance from equipment found in a modern conventional coal-fired power plant, is still unique and often must be approached differently with respect to design, engineering, operation, and maintenance.

AEP began the MT CCS II commercial scale application of the chilled ammonia technology with the philosophy that is typical for retrofit of major equipment across the AEP fleet. That philosophy is built upon over a century of power plant design and operating experience that has been incorporated and documented in engineering specifications, design criteria, and operating procedures which form a standardized technical basis for the engineering, design, installation and operation of any new equipment or system. However, AEP had less knowledge and experience with respect to the chemical process equipment that comprises the CAP. Much of the knowledge that went into the design basis for the MT CCS II project was obtained through operation of the PVF, interface with Alstom process engineers and operators, supplier interaction, and a core team of AEP process and operations engineers dedicated to understanding how this FOAK technology can be integrated into a power plant.

The outcome of AEP's experience with the PVF and efforts to better understand the CAP's application in a power plant setting resulted in two key findings:

1. Power plants and chemical plants have different operating philosophies.
2. Integration philosophy drives process efficiency, but also process complexity.

3.1 Operational Philosophy

Chemical plants are generally designed to produce a product to meet certain specifications, and the raw materials or feedstock required to produce the products in a chemical plant are generally supplied to the process in a uniform fashion with minimal variability. Process upsets can and do occur, but generally the processes and products within a chemical plant are held within specified tolerances, and consistent production schedules. Variables are minimized to reduce the impact to processes and products.

Mountaineer Plant, first and foremost, is a power generating station. It is designed and operated to generate reliable electricity to meet consumer demand. The demand for electricity is not constant, but often cyclical based on seasonal weather, time of day, or other factors. To meet this changing demand, generating units like Mountaineer must adjust their operating load. Load adjustments can be infrequent with the unit "base loaded" at a constant load for days or weeks; or frequent with the unit increasing and/or shedding hundreds of megawatts of its load in as little as an hour.

While Mountaineer's primary product (electricity) is consistent with respect to quality, its feedstock (the coal fuel), and the feed rate of that feedstock can vary dramatically (e.g. region of origin, chemical composition, heating value, moisture content, etc). Furthermore, variable fuel characteristics, coupled with variable operating loads, produce varying flue gas characteristics (e.g. temperature, moisture content, CO_2 content, chemical composition, etc). The flue gas leaving the plant ultimately becomes the feedstock for the post combustion CO_2 capture system. The challenge then becomes operating a complex system of chemical processing equipment, typically designed with a chemical plant operations philosophy of high consistency and low variability, with a continuously variable feedstock of flue gas, to produce a highly consistent, high purity (> 99.5% CO_2) product.

Lessons learned through the operation of the PVF continuously pointed to this difference in operating philosophy. Operation of the PVF proved that process variability could lead to upset conditions. Based on years of power plant operational experience, AEP incorporated “levers” into the technology and design of integrated systems such that if variability in one system arises, a “lever” is available that allows operations to adjust the process, and alleviate the problem before it becomes a significant issue and threatens unit operability or availability. Alstom and AEP, equipped with such lessons-learned from the PVF, approached the design and integration of the commercial scale project with the intent of ensuring that sufficient margin or “levers” existed in the system’s design to handle many of the variables that might be encountered. To achieve the necessary margin in the design, AEP worked closely with Alstom to develop a design that could accept as much process variability as practicable. This was accomplished by effective communication to develop:

- Detailed flue gas specifications with expected ranges for significant characteristics like temperature, moisture content, CO_2 content, SO_2 content, etc. which can vary based on fuel or unit operating parameters.
- Expected quality and temperature range of makeup water (which can vary significantly season to season) to properly identify equipment sizing, treatment needs, and heat exchanger capacities.
- Expected quality and quantity of available steam (which can change significantly in the heat cycle based on unit load changes and ambient conditions) to accurately identify the steam source, maximize efficiency, and minimize complexity of operations.
- A suite of material and energy balances depicting not only the main generating unit’s variability with respect to changes in load and ambient conditions, but also the CAP’s modeled process variability with respect to these conditions, which impacts sizing of equipment and auxiliary support systems.

The effort outlined above was the result of approximately four (4) months of collaborative effort between Alstom and AEP process engineers to take what was learned from the PVF, apply it to the ongoing engineering and design efforts of Alstom’s dedicated process engineering team, and produce a CAP design that both AEP and Alstom agreed could be successfully implemented and operated at a power plant on a commercial scale.

3.2 Integration Philosophy and Areas of Focus

AEP approached integration of the CAP at Mountaineer Plant from a conservative perspective. As mentioned previously, AEP has a long history of power plant design, engineering, operation and innovation. Over the years AEP has consistently pushed the industry limits to achieve higher efficiency, lower emissions, and enhanced performance and reliability across its fleet of generating units. These efforts have earned AEP a sense of what can practically be accomplished within the boundaries of the power plant with respect to safety, efficiency, performance, complexity, operations flexibility and return on investment.

The chilled ammonia process is a complex array of systems and components working together to capture and generate a high-purity stream of CO_2. It demands energy (in the form of heat and electricity) to accomplish this task. As a result there are several areas in the system and around the power plant that deserve to be explored to potentially recover that energy and reduce the CAP's overall energy demand. Areas considered for integration of heat and/or energy during Phase I of the MT CCSII project were:

- Flue gas heat recovery, upstream of the WFGD system.
- Heat of compression recovery from the CO_2 compression process prior to injection.
- Steam extraction from the Mountaineer steam turbine and condensate return from the CAP to Mountaineer's feed water heating system for heat recovery.
- Rich/Lean heat exchanger network design by Alstom to maximize the CAP efficiency (not discussed in detail due to Alstom intellectual property concerns).

AEP engineers considered the heat recovery options, and screened each option qualitatively and then quantitatively if the option appeared promising from a qualitative perspective. For example, the option for flue gas heat recovery to reduce CAP inlet temperature was immediately dismissed because of space constraints and the operational risks imposed to the main unit. Additional screening criteria employed by the team were:

- Qualitative complexity related to location of the equipment, required piping runs, control parameters, and additional equipment/components required to achieve proposed energy recovery.
- Qualitative assessment of impact of heat recovery to other systems/equipment.
- Quantitative assessment of maximum energy recovery potential (Btu or kJ), availability of energy with respect to time (e.g. is the benefit only seasonal, etc.) and average $/Btu based on Mountaineer-specific economic evaluation factors.
- Quantitative assessment of additional capital cost to achieve proposed energy recovery versus operating cost benefit of recovering the energy, and the payback period.

It must also be understood that in addition to the screening criteria above, AEP's integration assessments involved the recurring element of risk associated with the incorporation of FOAK technology in a slip-stream application. The team was reluctant to integrate systems to improve efficiency without a firm grasp of how the system was ultimately going to function. As with any technology, the level of integration will significantly improve as functionality and operations are better understood. This is evident in the power generation industry, as unit efficiencies have improved significantly over the years, while the premise of the technology remains essentially unchanged. CCS technology will experience similar improvements in its innovation over time. For the MT

CCS II project, AEP chose not to prematurely add to the complexity of "scaling to demonstrate and assess the technology," by attempting to over-integrate.

4.0 System Designs

4.1 Carbon Capture

4.1.1 Chilled Ammonia Process and Proprietary Information

Many design details for Alstom's CAP are considered proprietary information and are not included in this report. Examples of proprietary information, developed for the project, but not included herein are: process stream mass flows, temperature, pressure, and stream constituents at significant points in the process. Non-proprietary and/or generic discussions of the CAP process, its systems and interface with balance of plant systems, are presented herein.

4.1.2 Process Chemistry

The Chilled Ammonia process chemistry comprises gas/liquid phase mass transfer followed by chemical reactions in the liquid phase. The overall chemical reactions associated with the Chilled Ammonia Process carbon capture technology are depicted below:

$$CO_2\ (g) \Leftarrow\!=\!=\!\Rightarrow CO_2\ (aq)$$

Equation 1

$$NH_3\ (g) \Leftarrow\!=\!=\!\Rightarrow NH_3\ (aq)$$

Equation 2

$$NH_3(aq) + CO_2\ (aq) + H_2O\ (aq) \Leftarrow\!=\!=\!\Rightarrow (NH_4)HCO_3\ (aq)$$

Equation 3

$$(NH_4)_2CO_3\ (aq) \Leftarrow\!=\!=\!\Rightarrow (NH_4)NH_2CO_2\ (aq) + H_2O\ (aq)$$

Equation 4

The chemical reactions in the Chilled Ammonia Process are all reversible and their direction depends on pressure, temperature and concentration in the system. At low temperature, Equation 1 to Equation 4 are exothermic reactions from left to right direction requiring removal of heat from the process in order to maintain the desired absorption temperature. At high temperature Equation 1 to Equation 4 are endothermic reactions from right to left direction that require energy to release gaseous CO2. In addition chemical reactions associated with the removal of residual SO_2 from the flue gas in the absorber occur as described below.

$$SO_2\ (aq) + 2NH_3\ (aq) + H_2O\ (aq) =\!=\!\Rightarrow (NH_4)_2SO_3\ (aq)$$

Equation 5

$$(NH_4)_2SO_3\ (aq) + 1/2O_2\ (aq) \implies (NH_4)_2SO_4\ (aq)$$

Equation 6

The majority of SO_2 and other components, e.g. chlorides and fluorides, particulates are removed upstream of the absorption section.

4.1.3 Process Equipment

The CAP equipment can be divided into the following systems:

1. Flue gas cooling and cleaning
2. CO_2 absorption
3. Water wash and CO_2 / NH_3 stripping
4. Refrigeration system
5. High-pressure regeneration and compression

An overview of the CAP is illustrated in the process flow diagram shown in Figure No. 3 and a general arrangement of the CO_2 facility is depicted in Figure No. 4. The figures provide a frame of reference for the discussions contained in the following sub-sections.

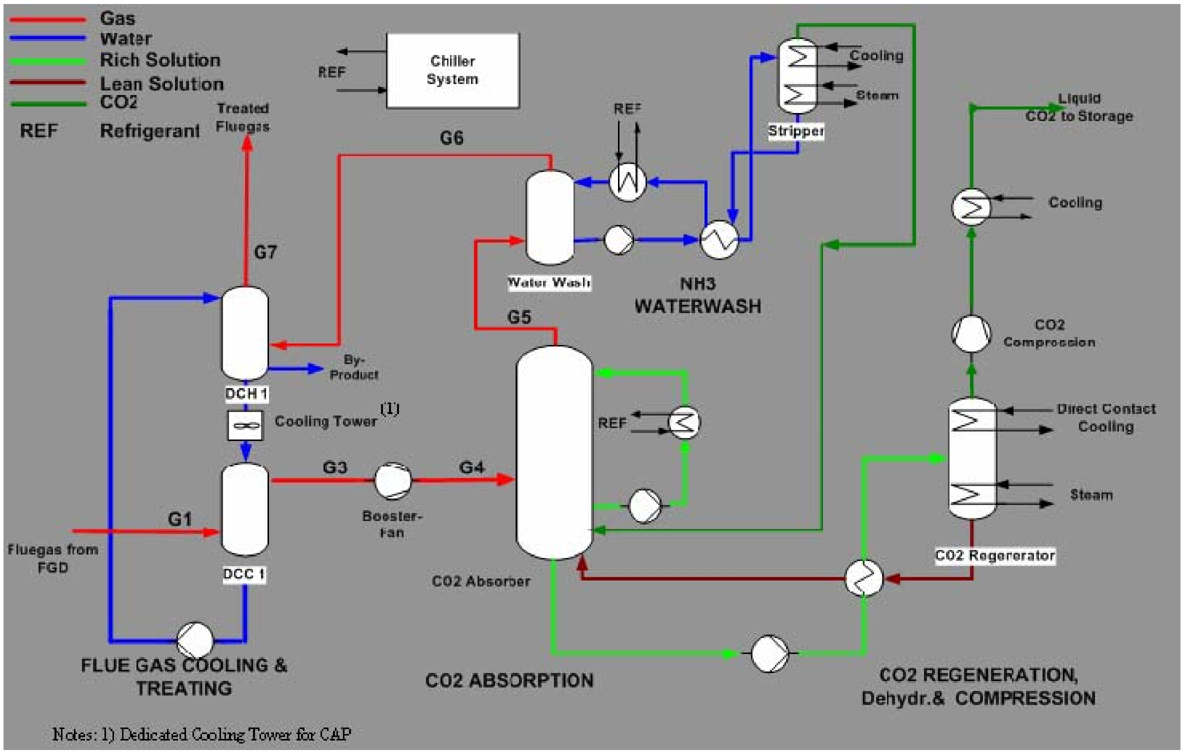


Figure 3 - Chilled Ammonia Process, Process Flow Diagram

Generic Process Description

A part of flue gas (G1) leaving the wet flue gas desulphurization (WFGD) is diverted by means of a dedicated ductwork to the CAP plant. Chilled flow gas from the Direct Contact Cooling Column (DCC1) (G4) enters the CO_2-Absorber and flows from there to the Water Wash Column for gaseous ammonia slip control. The flue gas stream (G6) returns to the Direct Contact Heating Column (DCH1) to scrub the remaining ammonia from the flue gas and to re-heat the treated flue gas. The residual (treated) flue gas (G7) leaving DCH is sent via a stack to atmosphere. The CO_2 rich solution from the CO_2 Absorber is heated by means of steam in the Regenerator to desorb primarily CO_2. Lean solution from the Regenerator returns to the Absorber. The CO_2 product is further treated to meet the pipeline specification and then compressed and pumped to the required delivery pressure.

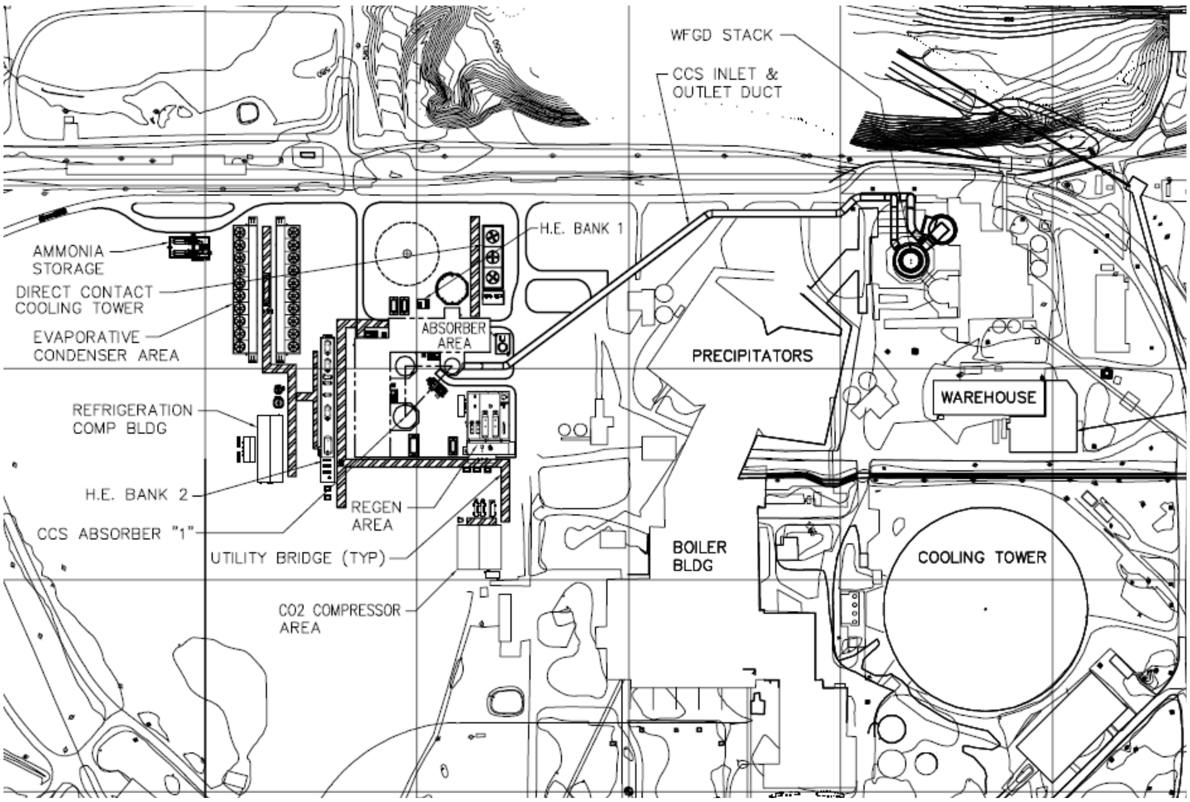


Figure 4 - General Arrangement of CO_2 Capture Facility

4.1.3.1. Flue Gas Cleaning and Cooling

The incoming flue gases enter the Direct Contact Cooler Column (DCC) at the bottom and pass through several contact beds. Treated flue gas from the Water Wash section is sent to the Direct Contact Heater Column (DCH). The main functions of both columns are to:

- reduce the flue gas temperature to the required temperature for the absorption process;
- condense the major part of the water vapor contained in the inlet flue gases to minimize the water ingress to the absorber system. At the same time the volumetric gas flow is significantly reduced and the CO_2 concentration increased,
- remove residual trace components, primarily SO_2 and other acidic components in the DCC ; and

- adjust the ammonia slip below 5 ppmv and to reheat the exiting flue gas from DCH.

The Direct Contact Cooler column (DCC), Figure 5, is a conventional packed tower with liquid recirculation through DCC and DCH followed by a back cooling system. Flue gas enters the DCC column inlet at the bottom and flows upwards through three packed beds. In the lower bed, SO_2 is absorbed by a separate circulating water loop. The SO_2 reacts with injected ammonia to form ammonium sulfate at a slightly acidic pH level. Other acidic components like chloride and fluoride are also removed. Anhydrous ammonia is added continuously to the water phase to maintain the optimum pH level. A surplus by-product water stream is pumped from the DCC sump to the DCH sump to adjust the ammonium sulfate concentration. As such, the DCC can remove acidic gaseous components, which are typically present in flue gases downstream of wet or dry flue gas desulphurization (FGD) systems without the need for additional upstream SO_2 control technology.

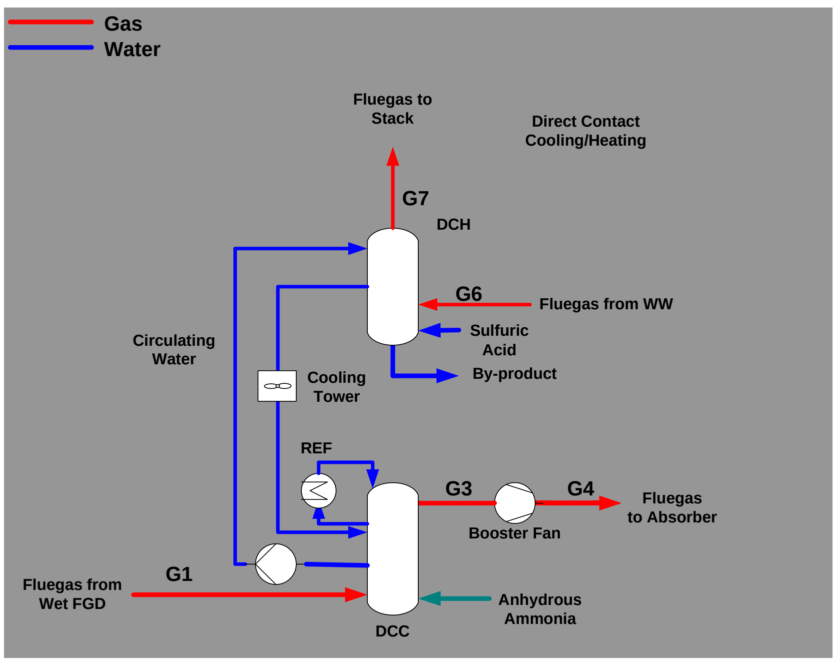


Figure 5 - Process Schematic of the Flue Gas Conditioning System

As the flue gases travel further up, it is contacted with cold circulating water sprayed on top of the mid bed of DCC to reduce the temperature and to condense the majority of the water vapor. The condensed water from the mid bed along with the condensed water from the top bed is sent to the DCH and then to the Cooling Tower system. As the gas flows further upward it is cooled in the top bed to about 6°C by means of a chilled water loop. Heat is rejected from this section to refrigerant from the chiller system. The water content of the flue gases leaving the DCC is less than 1 wt%. The flue gases from the DCC are first passed through a booster fan, which increases the pressure to overcome the total pressure drop of the overall flue gas path, before it is sent to the Absorber.

A Direct Contact Heating Column (DCH) consists of two packed beds and is used to reduce the ammonia level in the cold treated flue gases coming from the absorber/water wash section. The treated flue gas enters the bottoms bed of DCH at a temperature of about 7-10 °C. The inlet ammonia content of less than 200 ppm is reduced to about 5 ppmv at the outlet of the DCH by maintaining a low pH level in the bottoms circulating water loop. The pH level is adjusted by injecting sulfuric acid, which reacts with the ammonia to form ammonium sulfate. A bleed stream containing primarily dissolved ammonium sulfate at a concentration of 20-35 wt% is purged from this section for disposal or possible commercial use as fertilizer. A sulfuric acid storage and dosing system is provided.

Another purpose of the DCH is to raise the temperature of the treated flue gases to above 40°C before sending them to the stack. The treated flue gases are reheated in the top bed by direct contact with warm circulating water from the DCC. The cooled circulating water from DCH is sent after preheating to the Cooling Tower before it is returned to the DCC.

4.1.3.2. CO_2 Absorption

The flue gases entering the CO_2 absorber system, shown in Figure 6, contain less than one percent water vapor and low concentrations of SO_2, HCl, and particulate matter (PM). The CO_2 absorbers are designed as packed columns, which absorb CO_2 by means of an aqueous ammoniated solution. As the flue gases flow upwards, the downwards flowing solution absorbs the CO_2 and leaves the system as a CO_2 rich solution to the regenerator. Lean (low CO_2 concentration) solution from the regenerator is returned to the absorber to absorb CO_2.

A small amount of anhydrous ammonia reagent is added to replenish ammonia losses from the absorber section and is used to control the ratio of ammonia to CO_2 in the solution. An anhydrous ammonia unloading storage tank and feed system are provided to provide the reagent make-up.

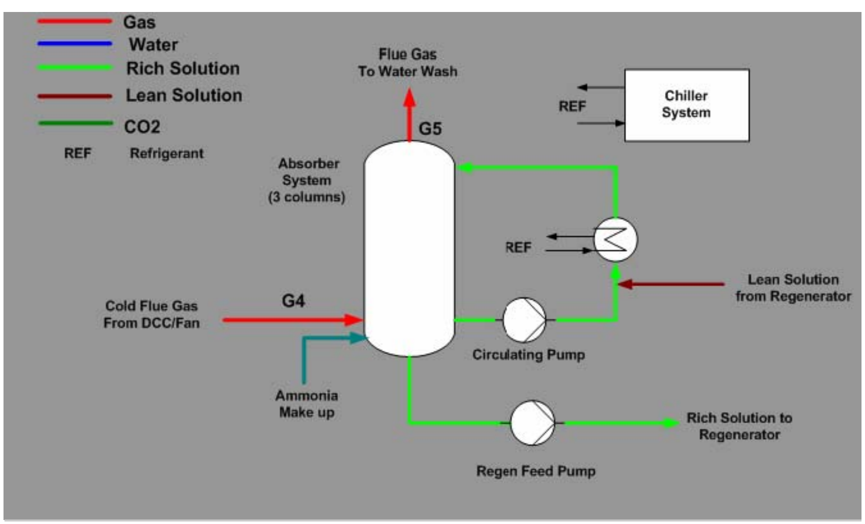


Figure 6 - Process Schematic of CO2 Absorption

The CO_2 absorber system consists of three packed columns. The optimized ALSTOM proprietary design minimizes the packing height while maintaining the ability to form ammonium bicarbonate and minimizing the ammonia slip from the absorber system. The absorber stages 1 and 2 absorb 85-90% of the CO_2 at a temperature of about 20 to 23 °C. The heat released by the exothermic reactions is removed by separate external circulating cooling loops for each absorber stage. The heat is rejected to the refrigerant from the chiller system.

The purpose of the third packed absorber stage is to reduce the amount of ammonia leaving the absorber section. This is accomplished by sending cold rich solution at a temperature of about 5 to 7°C to the top of the third column. The low ammonia equilibrium pressure at this temperature favors the absorption of gaseous ammonia into the liquid phase. The solution from the third absorber is returned to the bottom of Absorber 1. The flue gas leaving the third absorber stage is sent to the Water Wash Column. Rich solution is withdrawn from the bottoms of the first Absorber Column and pumped to the Regenerator. Lean solution from the Regenerator is returned to absorber system

4.1.3.3. Water wash and CO_2/NH_3 Stripping

The flue gases from the CO_2 absorption system is further treated in the water wash system to minimize the ammonia losses and keep the ammonia in the absorber system.

The flue gases from the third absorber enter the Water Wash Column, shown in Figure 7, at the bottom at a temperature of about 7°C. This flue gas is counter-current contacted in two packed beds with chilled stripped water, which is fed to the top of the water wash column. The inlet temperature of the chilled water is about 5-7°C, which favors the absorption of gaseous ammonia achieving a Water Wash outlet flue gas concentration of less than 200 ppm of ammonia. Some CO_2 is also co-absorbed. The NH_3 enriched water from the Water Wash Column is preheated with hot stripped water and sent to the NH_3 Stripper.

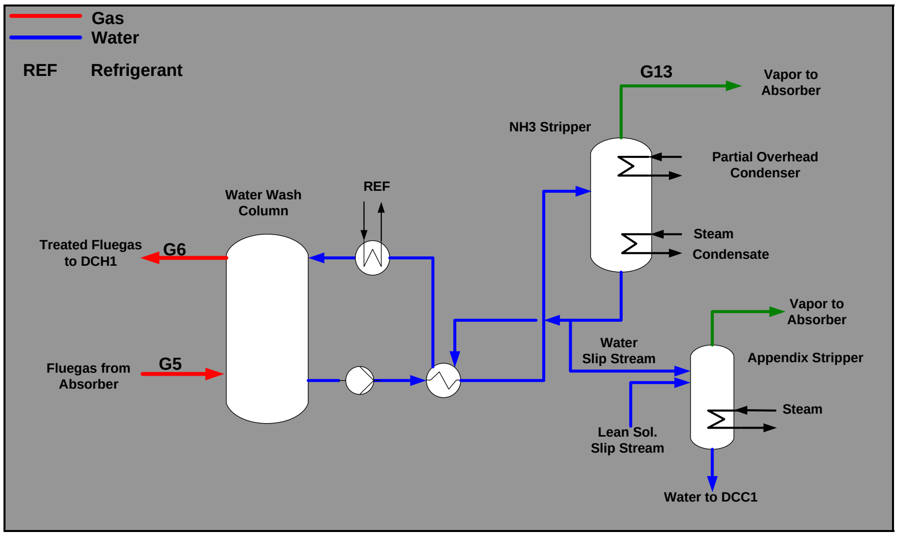


Figure 7 - Process Schematic of the Water Wash and CO_2/NH_3 Stripper System

The NH_3 Stripper is also a packed column consisting of a reboiler and a partial overhead condensing system. Heat is added to the reboiler by steam to raise the temperature and to generate sufficient vapor to strip off the ammonia and CO_2 from the wash water. The overhead vapor is partly condensed in the overhead condenser against cooling water or cold boiler feed water. The condensed water is returned as reflux to the Stripper. The stripper off gas containing water vapor, ammonia, and CO_2 is sent to the absorber system to recover the ammonia.

The hot stripper bottom flow is nearly free of ammonia and is first cooled in the cross heat exchangers against cold wash water from the Water Wash Column, before it is chilled against refrigerant provided by the chiller system.

A second stripper (Appendix Stripper) (not shown in Fig 3) is provided to balance the water inventory of the Absorber/Wash Water system and to remove any accumulated ammonium sulfate from the system, which is a heat stable salt and does not decompose at the prevailing temperature levels. The Appendix Stripper processes an intermittent slipstream of cold lean solution or a small amount of stripped water. Heat is added by means of a reboiler using steam. The ammonia rich overhead vapor stream from the Appendix stripper is sent to the absorber system. The ammonia sulfate enriched bottom stream is sent to the Direct Contact Cooler.

4.1.3.4. Refrigeration System

The Chiller System is a closed mechanical refrigeration system, consisting of two cascaded compressors to remove heat from different users of the process below the normal cooling water temperature. The circulating refrigerant is vaporized in the chillers at low pressure to cool the process and is afterwards compressed and condensed in an evaporative condenser if cooling water supply temperature is too high. The system provides chilling at two process temperature levels (+20 and/or +5 °C respectively). The evaporative condenser is a special air cooler where water is externally sprayed across the tube bundles to lower the condensing temperature and hence saving compression energy.

The chiller system utilizes ammonia as refrigerant. Ammonia is the most efficient refrigerant as it results in the lowest energy consumption. It has also very low global warming and ozone indices compared with other refrigerants. The chiller system is designed to allow a high flexibility regarding turndown conditions and discharge pressure of the compressor, in order to take advantage of changing ambient conditions.

4.1.3.5. High Pressure Regeneration and Compression

The CAP regeneration system, shown in Figure 8, consists of the lean rich heat exchanger network, the Regenerator Column and the CO_2 Wash Column.

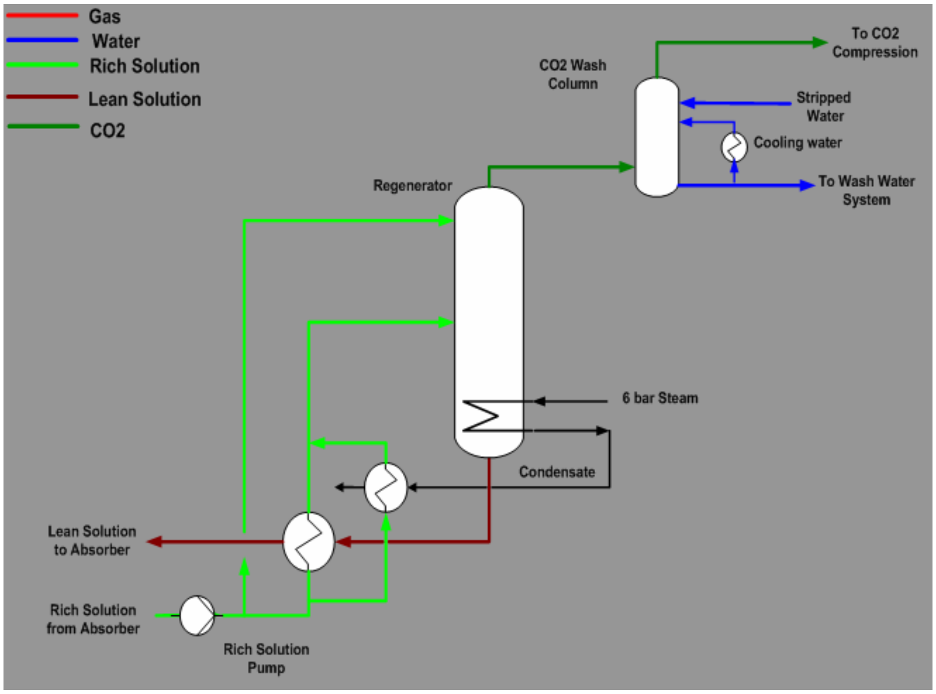


Figure 8 - Process Schematic of the Regenerator & CO_2 Wash

Rich solution, from the absorber system, is pumped by the Regenerator Feed Pump through a series of heat exchangers, where heat is recovered from the hot lean solution returning from the Regenerator bottoms and other heat sources, e.g. steam condensate.

The preheated rich solution is fed at elevated temperature to the lower section of the Regenerator column which at this temperature, part of the bi-carbonates decomposes to carbonate to release CO_2 vapor. The remainder of the rich solution is contacted with rising hot vapor, which is generated in the Regenerator Reboiler. At increasing temperature, more bi-carbonates decompose, releasing primarily CO_2 and small amounts of NH_3 and H_2O to the vapor phase. The Regenerator Reboiler is designed to maintain a temperature at the Regenerator bottoms of about 135 to 150°C, as required to achieve the specified low CO_2 loading of the lean solution. A small cold rich solution stream is sent to the top of the regenerator to provide reflux to the top packed bed.

The CO_2 rich gas from top of the Regenerator column is sent to the CO_2 Wash Column where it is cooled to about 40°C by direct contact with cold circulating water. Cold stripped water from the stripper column, enters the CO_2 wash column at the top to condense any residual moisture and ammonia. As stripped water flows down the column, it contacts with the rising CO_2 rich gas. Warm wash water from the CO_2 wash column is pumped through a heat exchanger that uses cooling water as cooling medium, to cool the wash water before circulating back to the CO_2 wash. Excess water from the bottom is sent to the Water Wash Column where it enhances the absorption of ammonia.

The cooled CO_2 stream is normally leaving the Regenerator/CO_2 Wash System at 20.5 bar. A pressure controller in the CO_2 product line controls the pressure and manipulates the inlet guide vanes at the CO_2 compressor inlet. The pressure of the CO_2 product leaving the Regenerator and CO_2 Wash Column is higher than for other post combustion carbon capture technologies resulting in a significant reduction of electrical power associated with downstream CO_2 compression.

The CO_2 compressor system consists of an integrally geared centrifugal compressor with two stages driven by an electrical motor, intercoolers and separators, a CO_2 Chiller/Liquefier, and a liquid CO_2 Pump. Liquefied CO_2 product from the surge drum is pumped to the required battery limit pressure.

4.1.4 Balance of Plant Systems

The Balance of Plant (BOP) discussions focus on the key systems/areas that needed to be integrated between the CAP and Mountaineer plant. The discussions also touch on design basis considerations for their integration to the plant. Systems to be addressed include:

- **Steam supply to the CAP & steam condensate return**
- **Flue gas exhaust from the CAP**
- **Process makeup water to the CAP**
- **Process wastewater**
- **CAP By-product stream**
- **Electrical power supply to the CAP**
- **Control systems**

Each of the BOP systems/areas listed above presented unique challenges and opportunities to the engineering and design team. Often determination of an interface point led to in-depth evaluation of design parameters, performance effects, and economics. The remainder of the BOP discussion will summarize options considered, as well as briefly discuss any issues encountered or gaps to be considered in Phase II detailed engineering.

4.1.4.1. Steam Supply and Steam Condensate Return

The Mountaineer Plant was put into service in 1980 and consists of a B&W boiler and an Alstom turbine set. With reference to Figure 9 below, the turbines are arranged in a “cross compound” arrangement due their large size. The arrangement consists of two turbine shafts, one consisting of the high pressure (HP) turbine and two low pressure (LP) turbines connected to one Generator, the other shaft consisting of the intermediate pressure (IP) turbine and the remaining two LP turbines connected to a second generator.

In order to efficiently supply the CAP with the required steam to be utilized as heating media, the water steam cycle of the Mountaineer Plant was investigated and modeled.

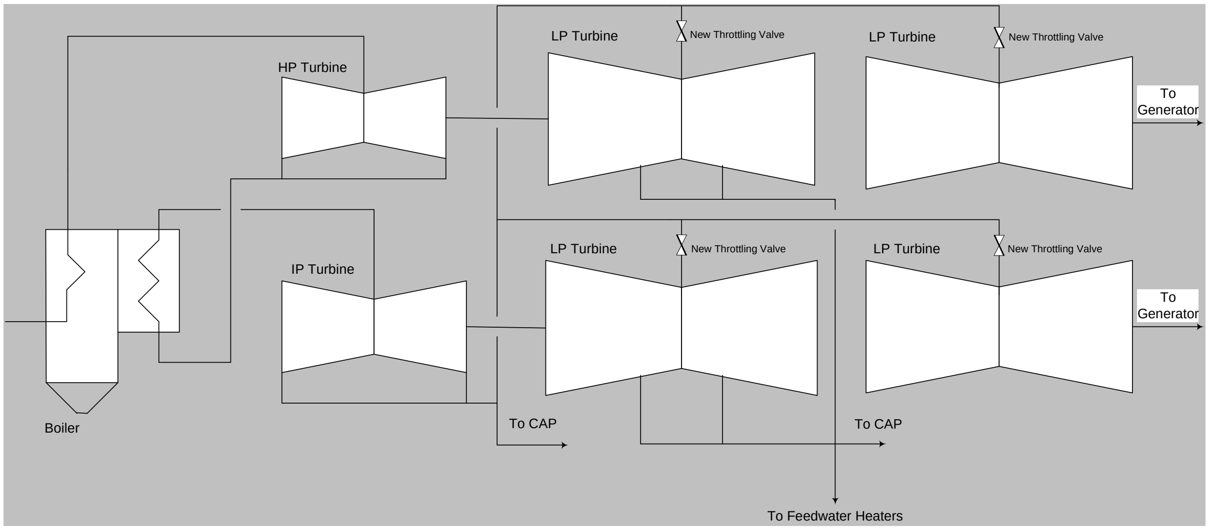


Figure 9 - Simplified Schematic of Mountaineer Turbine Arrangement With CAP Integration

The extraction of steam can be done in several locations; however the extraction philosophy and selection has significant impact on the final energy penalty of the capture plant addition. To illustrate this difference, a comparison was made for extraction from various locations in the steam cycle. The analysis included extraction from the cold reheat (CRH), compared to extraction from IP turbine, as well as from the cross-over (XO) between the IP turbine and the LP turbine. The results clearly indicate the advantage of choosing an extraction point with a pressure that is as close as possible to the required operating pressure. Figure 10 shows the effect based upon an appropriate thermal load chosen to determine the input on the steam cycle.

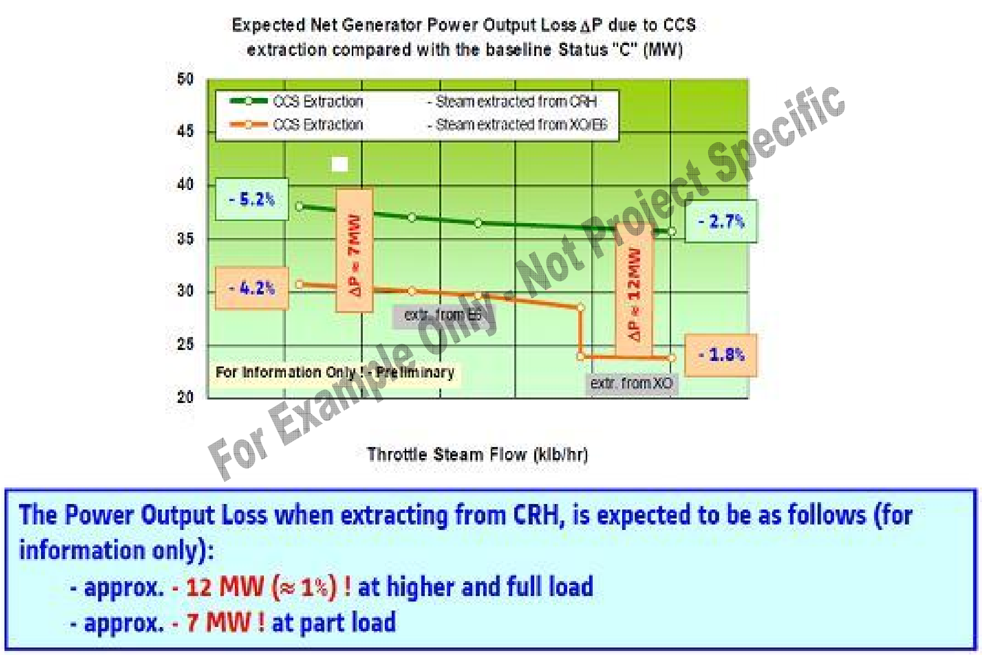


Figure 10 - Steam Extraction Location and Energy Penalty

Because this application is treating a slipstream of the flue gas, the capture plant is expected to operate at, or close to 100% of its capacity over the entire range of power plant loads from 55-100%. Due to the variance in available pressure at each extraction point during normal unit operation in this range, a single extraction point could likely not provide the required steam conditions to the CAP. The first approach investigated transferring to another steam extraction point at a certain unit load when the pressure in the IP/LP cross-over falls below the required value.

The advantage of this multiple extraction method is that it can be designed without any additional throttling devices in the steam line, and hence exhibits excellent performance at the design point. Disadvantages are the capital expense of multiple extraction ties, potential for turbine modifications to better match steam conditions, and the controls required to provide smooth transitions during load swings or other unstable events. As an alternative, the team considered the installation of throttling valves in the IP/LP cross-over line to eliminate the need to change extraction points with load changes. Correctly sized, these valves can provide minimal pressure drop at the design point when they are fully open and gradually close at part load in order to keep the extraction pressure constant.

Based on the desire to minimize extraction ties, eliminate significant turbine modifications, and keep the operation of the steam supply as simple as practical, it was decided to continue evaluation using throttling valves in the cross-over line between the IP and the LP turbines. Another factor that contributed to this decision is the fact that the AEP cross compound fleet of turbines are managed on a fleet basis, and any significant change to the Mountaineer turbines would make Mountaineer no longer interchangeable with the other turbines on the fleet.

In the end it was decided, based on steam cycle evaluation and process optimization, to extract steam at two different pressure levels: higher pressure steam for regeneration from the IP/LP crossover utilizing throttling valves, and also a lower pressure to supply steam for process stripping. Both extraction points are able to supply the required steam for the expected range of main unit operating loads 55% - 100% without moving to an alternate extraction location (with minimal impact on energy consumption). Condensate leaving the CAP boundary is returned to the Mountaineer feed water heating system to reclaim the condensate as well as offset a portion of the overall energy demand. To minimize contamination concerns, condensate storage “buffer” tanks are included in the design, which is continuously monitored for contamination.

Any retrofit installation requires a balance to be struck between practicality, performance, and cost effectiveness. For the MT CCS II project, the team spent considerable effort evaluating various methods of steam supply and condensate return and, as mentioned above in the explanation of process extraction alternatives, sometimes opted for operations simplicity/practicality over maximizing efficiency. Furthermore, the team investigated and identified areas where capital improvements could be made to existing equipment to reduce overall energy demand of the CAP. The most prominent example of this involved the existing boiler feed pump turbine control valves at Mountaineer.

The boiler feed pump turbine (BFPT) at Mountaineer plant is equipped with inlet control valves that have an unusually high pressure drop. This is problematic during summer conditions when the plant is operated at maximum load; the valves are wide open allowing for little to no control of the feed water flow. This limits the operation of the unit, as it limits the flow of feed water to the boiler, hence also limiting steam flow. In order to increase unit load under these conditions, steam to the BFPT can be taken from the cold reheat line instead of from the IP/LP cross-over pipe, which negatively impacts unit efficiency. The situation will worsen when combined with the steam extraction needs of the Mountaineer CO_2 capture plant. Heat balance analyses at peak summer conditions (cooling water inlet temperature 103°F) were performed, and demonstrated that without an upgrade of the BFPT valves, the throttle valves in the cross-over pipe will have to be further throttled to compensate for the pressure drop over the BFPT control valves. As Figure 11 illustrates, an upgrade of the BFPT valves could result in a considerable improvement of performance and efficiency during summer operation. AEP has been unable to justify an upgrade to these valves in the past because the savings during peak summer conditions (when the upgrade is most effective) could not offset the capital expenditure. AEP will likely carry out additional economic evaluations in Phase II to determine if the reduced energy demand of the CAP as a result of new BFPT valves would justify the upgrade.

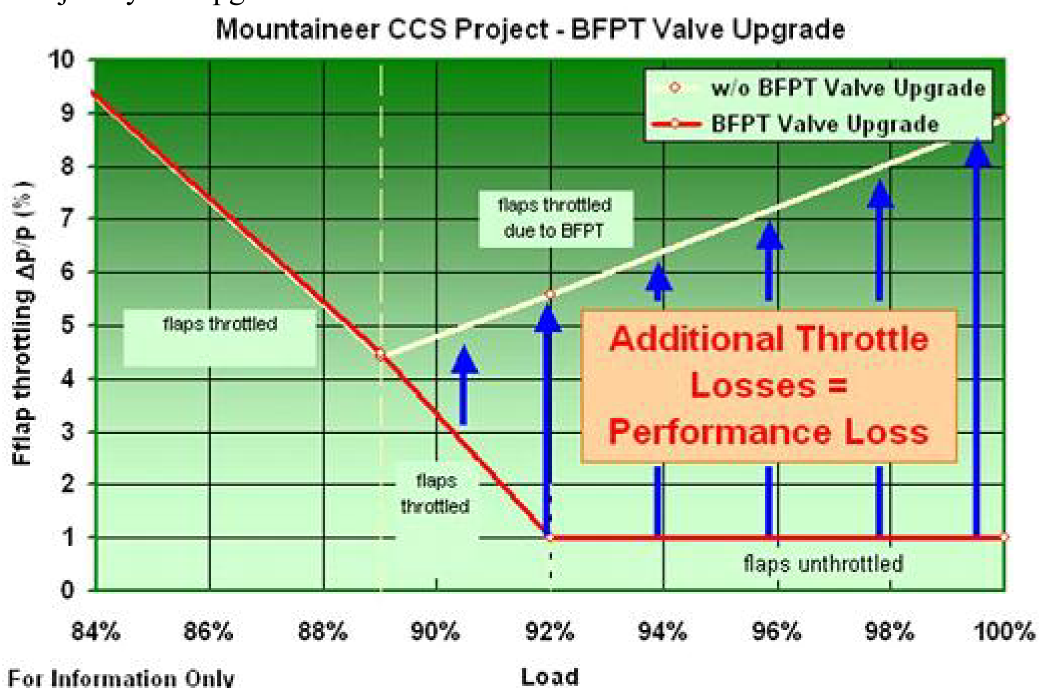


Figure 11 - Throttling of Crossover Valves with and Without BFPT Valve Upgrade

4.1.4.2. Flue Gas Exhaust

The team evaluated options for exhausting treated flue gas from the CAP. The three options considered were:

- Option 1 – CAP exhaust to existing Mountaineer stack,
- Option 2 – CAP exhaust to newly constructed stack close-coupled to the process island, and

- Option 3 – CAP exhaust to existing Mountaineer hyperbolic cooling tower.

AEP recommended early in the project that Option 3 be eliminated from consideration based upon technical and environmental risk factors associated with discharging flue gas in a cooling tower. Therefore, this option was not evaluated in detail.

With reference to Table 1, a cost comparison is shown for CAP flue gas exhaust Options 1 & 2. The major differences between options are as follows:

- Option 1 requires approximately twice the duct length as compared to Option 2. For Option 1, the CAP exhaust ductwork returns the flue-gas to the existing stack, whereas in Option 2, the exhaust is sent to a new dedicated stack in close proximity to the CAP facility. The estimated installed cost of the two options was nearly equal; Option 2 having a slight cost advantage of approximately 0.6%, which is negligible with respect to the accuracy of the estimate.
- Option 2 also offers an operating cost benefit over Option 1 due to lower auxiliary power consumption of the existing Inlet Duct Fans and the new CAP Booster Fan as a result of eliminating the return duct to the existing stack. Option 2 would operate at a lower static pressure to exhaust the flue gas out of a new, closely-coupled stack.

Description of Scope Items Evaluated	**Option 1**	**Option 2**
Flue Gas Ductwork Support Steel	Base	-41%
Flue Gas Ductwork Foundation	Base	-21%
CEMS allowance	Base	+121%
Modifications to FGD exhaust transition duct	Same	Same
Modifications to existing stack Base		Not Required
New Stack w/ FRP Liner & Foundation	Not Required	+850%[1]
FRP Ductwork (Supply Duct – 17’ Diameter)	Same	Same
FRP Ductwork (Return Duct - 15' Diameter)	Base	-95%
Expansion Joint (Supply Duct)	Same	Same
Expansion Joint (Return Duct)	Base	-83%
Insulation and Lagging (Return Duct)	+$1M	N/A
Vents and Drains system for Supply Duct	Same	Same
Vents and Drains system for Return Duct	Base	-94%
TOTAL	**Base**[2,3,4]	**-0.6%**[1,2,3,4]
Notes:		
1) New stack capital cost was based on vendor quote.		
2) Duct supply lengths are 1524 linear feet for each option except that return duct lengths are 1825 and 100 linear feet, respectively for Options 1 and 2.		
3) Cost for drain system includes FRP piping, pumps and tanks, with heat tracing, & insulation.		
4) Mercury monitor is included in CEMS allowance.		

Table 1 - Cost Comparison of CAP Flue Gas Exhaust Options

Based on the economic results of this evaluation, the project team recommended Option 2, where the CAP exhaust is sent to a new dedicated stack. However, uncertainties associated with modeling and permitting a new stack restricted AEP from considering this option for the Phase I conceptual design, and it was determined that selecting Option 1 was the more conservative approach. Option 2 could be revisited in Phase II (detailed engineering and design) and ultimately implemented, depending on the regulatory requirements at the time of implementation.

With the Option 1 configuration, there was concern with introducing cooler CAP gas back into the saturated FGD exhaust gas stream. This was analyzed during Phase I and determined that the change in mass flow through the stack for this option is negligible. The flue gas temperature decrease in the existing stack due to the cooler CAP flue gas re-entry also has minimal, if any, effect on the flue gas buoyancy in the existing stack. The volumetric flow through the existing stack for Option 1 is based on the mixture of 84% higher temperature untreated flue gas and 16% lower temperature treated flue gas. The decrease in stack velocity is considered to be negligible. The existing stack drainage system is adequately sized to handle the additional moisture that will condense in the stack due to flue gas cooling. Estimated stack condensation was calculated using ASPEN process modeling software to determine the effect of mixing the two saturated gas streams at different temperatures, and is based on a flue gas moisture content of approximately 10% to 15% by volume.

The proposed supply and return ducts are round fiberglass reinforced plastic (FRP) based on its cost effectiveness and resistivity to corrosion. No insulation is included for the supply duct since heat loss is not a concern. Unlike Option 1, the exhaust duct for Option 2 will not be insulated, as the run of ductwork to the new stack is no more than 100 feet. It should be noted that, based on feedback from FRP vendors, shop fabrication may be possible for the 15’ diameter FRP which would yield substantial cost savings.

For Option 2, the new stack height considered in the Phase I evaluation was 593.5’ based on “Good Engineering Practice" (GEP) stack-height. The basic stack components include a concrete shell and a 15’ diameter FRP flue liner. During Phase II of this project, a dispersion model should be performed to determine the necessary stack height, which may be lower than the estimated GEP height, potentially reducing the cost of Option 2.

In addition, a more-detailed computational fluid dynamics analysis is recommended to determine any modifications required to existing duct work and/or flow distribution devices in the existing stack. A flow model analysis is also recommended to optimize the drain collection system within the ductwork and stack for any potential impacts related to the design. A transient analysis is also recommended during Phase II to minimize the duct design pressures and potentially reduce costs for either option.

4.1.4.3. Process Makeup Water

The Makeup Water System for Mountaineer CCS II Project is designed to receive raw water from the Ohio River using the plant’s existing river water makeup system and to treat the water for use by various consumers (shown in Table 2) including evaporative condensers, pump seal water, washdown hose stations, process water makeup, and direct contact cooling (DCC) makeup. The primary demand for makeup water is the CAP refrigeration system. Three (3) existing pumps rated at 20,000 gpm each furnish river water makeup from the Ohio River. River water makeup pump capacity is considered to be more than adequate to supply the additional makeup required for the CAP process. The entire makeup water stream for the capture plant is treated by chlorination for biological control and by chemical precipitation and clarification, primarily for removal of total suspended solids (TSS) that might interfere with operation of the evaporative condensers and other equipment requiring makeup water. Treatment will reduce the concentration of iron and other heavy metals that might be present in the water. The makeup water treatment plant required for the capture plant at Mountaineer will consist of the following principal components:

- Rapid mix tank
- Reactor tank
- Clarifier/thickener
- Sludge recirculation pumps
- Sludge blowdown pumps
- Chemical storage tanks
- Chemical feed pumps

Item	Flow Rate (% of CAP Total Makeup)
Evaporative condenser evaporation	51%
Evaporative condenser blowdown	26%
Pump seal cooling water	4%
Washdown hose stations	4%
Process water makeup (clarified water)	3%
DCC makeup (RO product)	7%
Filter backwash and RO concentrate	3%
Makeup water clarifier sludge blowdown	2%
Total makeup requirement	100%

Table 2 - Mountaineer CAP Makeup Water Usage

The portion of the makeup water used for DCC makeup requires additional treatment to produce relatively high purity water. The existing plant condensate system can not support the maximum demand of the CAP. Therefore, makeup to the DCC will receive treatment by additional multimedia filtration and a new two-pass reverse osmosis system. The multimedia filtration and reverse osmosis system will consist of the following principal components:

- Multimedia filters, including filter feed pumps, filter vessels and media, filter backwash pumps, and filter air scour blowers,

- Reverse osmosis system, including two-pass reverse osmosis system, cartridge filters, and RO booster pumps
- Chemical feed systems, including antiscalant, sodium bisulfite, and caustic soda
- RO cleaning system, including solution tank, cleaning pump, and cartridge filter
- RO permeate tank and forwarding pumps

The Ohio River water used for makeup is relatively high in concentrations of total dissolved solids (TDS), conductivity, sulfate, and total hardness. The typical Ohio River water quality is provided in Table 3 below.

Parameter	Nominal	Range
Iron, Fe (mg/l)	3.29	-
Copper, Cu (µg/l)	5.39	-
Sulfate, SO_4 (mg/l)	131	56 - 169
Total Hardness, as $CaCO_3$ (mg/l)	197	95 - 210
Chloride, Cl (mg/l)	60	14 - 60
Total Dissolved Solids (mg/l)	-	300 - 500
Conductivity @ 25 ºC (µmho)	600	300 - >1000
Total Suspended Solids	30	<100
pH @ 25 ºC	7.7	6.4 – 9.1
Alkalinity, Total (mg/l as $CaCO_3$) -		80 max.
Calcium, Ca (mg/l)	-	7 - 50
Magnesium, Mg (mg/l)	10	7 - 17
Sodium, Na (mg/l)	-	11 - 35
Potassium, K (mg/l)	-	2 - 4
Manganese, Mn (mg/l)	-	<0.5
Total Organic Carbon (mg/l)	-	2 - 17
Total Kjehldahl Nitrogen (mg/l)	-	0.3 – 1.41
Total Phosphorus, P (mg/l)	-	0.03 – 0.24
Silica (mg/l)	-	0.7 – 6.3
Temperature, ºF	60	33 - 90
Pressure, psig	-	20 - 50

Table 3 - Typical Ohio River Water Quality

4.1.4.4. Process Waste Water

The CAP is designed to minimize wastewater production, as liquid streams generated by the process are either usable (as in the case of the ammonium sulfate by-product to be discussed later), or returned, to the extent practical, back to the process. The most significant non-usable liquid streams generated from the cooling of the flue gas and capture of CO_2 are 1) condensed moisture from the flue gas entering the CAP and 2) evaporative condenser blowdown from the CAP refrigeration system.

Moisture condensing out of the flue gas as it enters the CAP via the supply duct will be collected and sent back to the main stack drain system which flows to the plant's wastewater ponds and eventually to an outfall. The supply duct will have a dedicated drain system, which will be separate from the drain tanks of the return ductwork. The flue gas condensate collected in the flue gas return duct will be sent to a local drain tank. As the liquid in the drain tanks reaches the high level, the condensate will be pumped back to the CAP Island to be re-used in the process.

The separate drain systems are a site-specific requirement and are provided as a precaution in the event that a CAP upset increased the ammonia concentration in the return flue gas condensate, which could potentially impact the plant's ammonia discharge limits. It is expected that as the CAP technology is demonstrated, a common drain system can be employed.

The design and optimization of gutters and liquid collectors in the ductwork and stack flue are dependent on the duct/stack geometry, gas velocity, and flow patterns. Therefore, a flow model study is recommended in Phase II to determine the optimum location and configuration of the gutters and liquid collectors within the ductwork and stack.

Evaporative condenser blowdown will be discharged to the existing plant wastewater ponds. A blowdown sump and two (2) 100% capacity blowdown sump pumps will be added to pump the evaporative condenser blowdown to the interface point with the existing line. Clarifier sludge blowdown, multimedia filter backwash and RO concentrate will be discharged to the water treatment building sump, from which the wastewater will be pumped to the wastewater pond. Solid waste from the sump will be collected and taken to the landfill.

Sanitary wastewater will be collected from all CAP facilities that use potable water (with the exception of some emergency showers) and will be connected to the existing plant sanitary wastewater collection system, which discharges to the New Haven, West Virginia municipal system through a duplex pneumatic lift station.

4.1.4.5. CAP Byproduct Stream

The CAP produces a byproduct stream rich in dissolved ammonium sulfate. This stream must be treated before release from the plant. Possible treatment solutions for this waste stream include ammonium sulfate recovery for commercial end-use, reaction of ammonium sulfate to a secondary byproduct that can be either sold commercially or disposed of in a landfill, and reuse of the ammonium sulfate solution within the Mountaineer boiler gas path for additional emissions controls (enhanced NOx and/or particulate removal).

The CAP byproduct stream is proposed to be a 25 weight percent (wt%) (typical) aqueous solution of dissolved ammonium sulfate. In order to accommodate a large range of composition for the CAP bleed, the CAP byproduct treatment options were designed to accommodate a stream as low as 15 wt% total dissolved solids (TDS). Based on the need for operational flexibility, a total of four additional tanks were provided to handle dilute CAP by-product that may be less than 15 wt%. As such, for any upset or maintenance periods when TDS is below 15 wt%, the treatment option would accommodate design flow while the residual would be routed to the storage tanks. When operation of the CAP returned to normal operation and the CAP byproduct stream was greater than 15 weight percent TDS, the low and low-low purity storage tanks would be drawn down, mixed with higher purity byproduct and processed through the treatment option to the extent possible. As the CAP technology matures, it is expected that the additional ammonium sulfate tank capacity for dilute by-product handling may not be required.

Options for re-injection into the Mountaineer boiler gas path were eliminated from consideration. With a variable byproduct concentration, unknown impacts to existing equipment, and other uncertainties, this option presented too high a risk to integrate at the current time. As the CAP is operated and the byproduct stream characteristics and flow rate are better understood, the team might consider integrating this stream back into the plant for additional means of emissions control. The following options were evaluated for treatment and handling of the byproduct stream:

- Concentration of the stream to a crystallized ammonium sulfate for resale as a fertilizer product (Base Case Option).
- Concentration to a 40 wt% ammonium sulfate solution for resale as a fertilizer product (Option 1).
- Alternate process referred to as “Lime Boil” to react ammonium sulfate with lime to recover ammonia and produce gypsum that could be combined with Mountaineer’s gypsum waste product from the FGD (Option 2).

The project team contacted Original Equipment Manufacturers (OEMs) to assist in the development of heat and material balances, Process Flow Diagrams (PFD) and Process & Instrumentation Diagrams (P&ID), equipment lists, and utility consumption values. These items were used, in turn, to develop capital and operating cost estimates for each option so that they could be assessed from an economic perspective. AEP contacted potential end-users of the fertilizer products to insure that the product would meet agricultural specifications and could in fact be considered for beneficial use. Potential end-users in the region indicated that either a crystallized product or a 40 wt% liquid product would be desirable. Estimated constituents of the byproduct were within acceptable agricultural specifications, so AEP proceeded with a design basis that relied upon beneficial use of the byproduct stream in lieu of disposal. AEP must take steps in future project phases, however to ensure a long term purchase contract can be established and that byproduct specification estimates do not change significantly. The estimated costs for the three treatment options considered are summarized below in Table 4 for total capital cost (CAPEX) and first year operating costs (OPEX).

Case	CAPEX	OPEX
Base Case (Crystallized Ammonium Sulfate)	Base	Base
Option 1 (Ammonium Sulfate Solution)	-32%	+2.7%
Option 2 (Lime Boil Process)	-19%	+148%

Table 4 - Capital & Operations Cost Summary for Byproduct Handling Options

The project team decided that generation of a concentrated solution of ammonium sulfate (Option 1) is implemented as the CAP byproduct stream design basis. Generation of crystallized ammonium sulfate is also a viable alternative. Both employ some of the same equipment, so choosing the 40 wt% option as the design basis and allowing space in the equipment layout offers the opportunity at some point in the future for producing both a solid product and an aqueous solution. This provides maximum flexibility to increase marketability of the end product. As such, the conceptual design of the plant included space to add crystallized byproduct processing equipment with bagging and 15-day solid product storage capability. It should be noted that there might be occasions where the ammonium sulfate can not be sold.

The lime boil process was not selected for the conceptual design due to its expected higher operating costs, and increase in solid waste material to the plant's landfill.

4.1.4.6. CO_2 Compression

Five basic configuration options were evaluated to pressurize CO_2 from a nominal 300 psia to 3,000 psig. Two of the five options evaluated were an emerging compression technology and are not discussed in this report due to intellectual property concerns with the technology supplier. The remaining three alternatives are:

- Option 1 – Integrally-geared, inter-cooled, centrifugal compressor with after-cooler to 1,320 psig followed by pump and after-cooler to 3,000 psig.
- Option 3 – Integrally-geared, inter-cooled, centrifugal compressor with after-cooler to 860 psig followed by cooling with cooling water and liquefaction via heat exchange with a refrigerant. Liquid CO_2 then pumped to 3,000 psig.
- Option 4 - Integrally-geared, inter-cooled, centrifugal compressor with after-cooler to 3,000 psig.

Process Flow Diagrams (PFDs) were developed for each option and are shown in Appendix C. Based on the PFDs developed, equipment suppliers and OEMs were contacted in order to procure budgetary proposals, performance data and cost estimates for the equipment defined by the configuration descriptions given above.

A summary of the auxiliary power requirements to pressurize CO_2 to 3,000 psig for each of the options is presented in Table 5 below. It should be noted that the refrigeration auxiliary load for Option 3 is assessed at the peak summer condition, thus the value in the table is a worst-case auxiliary load. During other seasons, especially winter, this value would be less since at lower ambient temperatures, the refrigeration system could be bypassed and the water-cooled after-cooler would provide the necessary cooling.

Load 1		3	4
Compression, KWE	5,980	4,630	8,996
Pump, KWE	1,321	1,440	0
Refrigeration, KWE	0	1,233*	0
Cooling water pump, KwE	160	55	165
Subtotal, KWE	7,461	7,358	9,161
Total, KWE	7,461	7,358	9,161
* - Peak condition; considerably less during winter months. Calculated annual average is 440 kWe.			

Table 5 - Summary of Compression Auxiliary Power Requirements

A summary of the cooling water service requirements for each of the options is presented in Table 6 below. This cooling water is assumed to be available from Alstom's cooling tower and would be piped from the Direct Contact (DC) cooling water circuit. Alstom has verified that they can provide cooling water at the temperature required by the compression equipment.

Option 1		3	4
Cooling water, gpm	6,800	2,340	7,000

Table 6 - Summary of Cooling Water Requirements

Process equipment costs were either estimated by WorleyParsons or obtained from equipment suppliers' budgetary proposals. Compressor cost data for Options 1 and 3 were furnished by Alstom. A summary of the equipment costs for the various CO_2 compression options is shown in Table 7.

It should also be noted that each of the options could be configured for heat recovery with the CAP system or the main Mountaineer unit. However, cursory analyses indicated that the CAP and plant processes would benefit little from the heat available from integrally geared machines with inter-stage cooling. Lower injection pressures as experienced on the Mountaineer CCS validation facility also suggested that available heat of compression would be reduced from initial expectations. Furthermore, the additional capital costs for equipment to recoup the available heat (pumps, heat exchangers, piping, etc), would be significant and therefore the team did not focus its efforts in Phase I on recovering the heat of compression.

As shown in Table 7, Option 1 – compression in an integrally-geared centrifugal compressor to an intermediate supercritical condition followed by cooling and pumping to final pipeline pressure (most flexible operating condition), is the most economical solution from an equipment cost perspective followed by Option 3, which uses sub-critical compression with liquefaction. Although Option 3 is penalized from a CAPEX perspective due to the high cost of the refrigeration equipment, the lower operating costs associated with this option offset a significant portion of the capital.

In Table 7 and all other cost tables in this section, estimated costs are presented in the following manner:

- Option 1 is held as the "Base" cost option.
- All other costs for the other options identified will be represented as a percentage difference (+/-) from the Base.

OPTION	**1**	**3**	**4**
Equipment Item	INTEGRALLY-GEARED COMPRESSOR/ PUMP	INTEGRALLY-GEARED COMPRESSOR/ LIQUEFACTION/ PUMP	INTEGRALLY-GEARED COMPRESSOR/ NO PUMP
CO_2 KO Drum	Base	0%	0%
Compressor and Motor	Base	-2.5%	+107.4%
Inter-/After-cooler Base		-35.8%	+27.0%
Refrigeration, USD	n/A	+$2.9M	n/a
CO_2 Receiver	Base	+44.7%	n/a
Pump and Motor	Base	+12.9%	n/a
Pump VFD	Base	+9.0%	N/A
Pump After-cooler	Base	n/a	n/a
Total Equipment Cost	Base	+47.3%	+25.7%

Table 7 - Summary of Compression Equipment Cost

The total evaluated costs, shown in Table 8 indicate that, over the long term, Option 1, integrally-geared compression followed by supercritical CO_2 pumping is the least cost option with Option 3, sub-critical compression, cooling and CO_2 liquefaction followed by pumping, being the next least cost option.

OPTION	**1**	**3**	**4**
Equipment Item	Integrally-Geared Compressor/ Pump	Integrally-Geared Compressor/ Liquefaction/ Pump	Integrally-Geared Compressor/No Pump
Total Equipment Cost	Base +47.3%		+25.7%
Auxilliary Power Cost (First Year)	Base	-12.0%	+22.8%
Total Operating Cost, Net Present Value (NPV), over 10 Years	Base	-12.0%	+22.8%
Total Evaluated Cost (Total of Equipment & NPV Cost)	Base	+6.5%	+23.7%

Table 8 - Total Evaluated Cost Summary for CO_2 Compression

The study evaluation for the compression system generated the following key takeaways:

- All options evaluated are technically feasible
- Based on experience with injection at Mountaineer, pressures below 3000 psig are likely to be sufficient to inject CO_2 into the targeted underground reservoirs, which would result in additional power savings and reduced total evaluated costs for options having the flexibility to produce lower injection pressures. Compression to an intermediate pressure, followed by variable speed pumping to the final injection pressure offers greater flexibility and efficiency over the life of the system as compared to full compression to the maximum expected injection pressure.
- Performance and total evaluated cost for Option 1, compression with an integrally-geared compressor to an intermediate supercritical condition followed by cooling and pumping to final pipeline pressure, and Option 3, subcritical compression, cooling and CO_2 liquefaction followed by pumping to final pipeline pressure, are similar. Detailed engineering and design in Phase II of the project, focusing on these options, is recommended to determine the best option for Mountaineer plant.

4.1.4.7. Electrical Power Supply

The electrical power supply needs to the CO_2 capture plant are based on an analysis that considered estimated electrical loads, steady state load flow requirements, large motor starting scenarios, and resultant bus voltage and short circuit duty to size and determine equipment ratings. The project team recommends that two new 138kV lines to a step-down station be installed to serve CAP and associated BOP systems. The new 138 kV lines also require modifications and additions to the existing 138kV auxiliary substation at Mountaineer. A summarized breakdown of the scope of integration required to supply the necessary electrical power to the Mountaineer CCS system is as follows:

- Installation of multiple additional circuit breakers, switches, control cables and breaker foundations
- Installation of three phase metering class capacitance coupled voltage transformers (CCVTs) on 138kV bus #1 and bus #2 and single phase metering class CCVTs on each feeder. The existing CCVT structure and foundation for bus #1 CCVT will be used, with new CCVT foundations and structures required on bus#2 and all feeders.
- Expansion of the existing 138 kV substation control house by 10ft in order to fit the new panels. This involves land improvement work to restore a ditch right next to the control house.
- Expansion of the existing fence and addition of new ground grid.
- Upgrade of existing battery and charger to a larger capacity.
- Miscellaneous bus work to accommodate the two new CCS feeders.
- Installation of two steel poles inside the substation.
- Installation of fiber-optic line between 138kv mountaineer station and 765kv mountaineer station for metering data transfer.
- Installation of a fiber multiplexer and any other necessary electronics to provide as much bandwidth as needed to support the telecommunications needs of the capture plant.

4.1.4.8. Control Systems

All control and monitoring associated with process systems and equipment will generally be from the Distributed Control System (DCS) terminal located in a dedicated CCS control room located near the CAP. The CCS control room will be designed as a continuously occupied control center that will accommodate two (2) operators and a shift supervisor. The CCS control room will include all the necessary displays for safe operation of both the capture and storage systems.

Main power distribution breakers associated with the CCS plant, rotating equipment start / stop, valve positioning, and subsystem start / stop (e.g., compressor) will be initiated from the CCS control room. Sufficient instrumentation and equipment feedback status will be provided through the DCS to ensure safe and proper operation of the process. The DCS will be provided with sufficient redundant instrumentation, controls, processors, power supplies, and operator interface and data communication equipment to ensure that the critical operational or protection functions continue to operate when there is a failure of a component. The design intent was to ensure that no single point of failure above the I/O card level would limit the ability to control the CCS plant process systems.

Normal control and monitoring will be from the DCS Operator Interface Terminal (OIT). Local control will not be possible (other than E-stop functionality) until the operator has selected “local” control from the OIT. Local operator control of subsystems or individual equipment can be achieved and may be required when equipment is out of service (to perform specific maintenance operations), or it has been discussed with Plant Operations and determined that local control is necessary. Local packaged equipment provided with its own independent control microprocessor, such as an air compressor, will be capable of being placed into local control, or controlled via the DCS. Packaged control systems will be provided with a "Local / Off / Remote" selector switch. Whenever the selector switch is in the local position, an alarm will be initiated in the DCS and the packaged equipment can then be fully controlled and operated locally. With selector switch in remote position, the packaged control system will be capable of accepting high-level commands such as start / stop from the DCS; however, protection and control of the packaged equipment is supervised by the packaged control system microprocessor.

Monitoring functions for the equipment or systems will be maintained at the OIT in both the "local" and" remote" modes. The local panel will include indication that control is "local" or "remote" and monitoring functions may be available in both modes. At a minimum each OIT will have the capability to open / close breakers, start / stop motors, open / close valves, start / stop automatic sequence controllers, and position process regulating devices. Additionally the operator will be able to select automatic / manual operation of equipment, adjust set points, and perform manual signal selection, process monitoring, alarm acknowledgement, and equipment "tagout" from the OIT. The DCS OITs will be provided with multiple levels of security to control access to the above functions. OIT hardware topology will allow access to all DCS logic controllers from every OIT. Multiple OITs will be provided such that a failure of a single OIT will not result in the loss of communication with the DCS logic controllers. The total number of OITs will be based on the number of operators and process systems. Shown in Table 9 are the proposed location(s) of OITs for control and monitoring:

Control / Monitoring / Process	CCS Control Room	Local	Notes
BOP Systems	X		
CAP System	X		
By-product Handling Systems	X X		
Truck Loading / Unloading	X		(1, 2)
CO_2 Compression System	Included in CAP System	X	
Injection Well WMMS	X X		(1)
Notes: (1) Alarms in the CCS control room via the DCS. (2) Monitors in the CCS control room to display local camera video.			

Table 9 - Summary of CCS Operator Interface Terminal Locations

Graphic displays will be developed to monitor and control all process systems directly controlled by the DCS. This includes specific equipment that may only use high level control functions (e.g., compressor) and monitoring through the DCS.

The DCS will monitor data returned from the CO_2 storage Well Maintenance & Monitoring System (WMMS) PLC at each well site and compare this data to the data from instrumentation monitoring pipeline leakage. CO_2 leakage will be alarmed in the CCS control room for operator action.

A dedicated monitor in the CCS control room will be used to display status of selected Mountaineer power block systems (unit load, etc.). The monitor will be connected through the plant LAN, but will not have capability of controlling any of the main power block systems. Similarly, the CCS DCS will be connected to the plant Local Access Network to allow the CCS systems' status to be displayed in the main Mountaineer control room.

The DCS architecture will include a data historian to collect and store a history of process values, alarms, and status changes. The historian will operate on a dedicated workstation or processor and not interfere with the operation of the DCS network. The configuration will include buffered signal collection to prevent interruption of data collection during a server outage. The data collected will be time stamped to allow retrieval of information in a chronological order of events and values. The historian will include pre-configured reports, as well as, the ability to create custom reports. The historian will be accessible from any workstation on the network or a PC that has network access.

The flue gas supply to the CAP and return gas to the plant stack will be monitored by dedicated Continuous Emissions Monitoring System (CEMS) type analyzers controlled by local PLCs. The data collected by the CEMS will be communicated to the CCS control room via data link. The collected data will also be communicated and integrated into the plant stack CEMS so that proper emissions data can be reported to satisfy regulatory requirements.

4.2 Carbon Storage

4.2.1 Introduction and Background

The Phase I scope of work for carbon storage had the objective of building on the earlier work performed in the DOE sponsored Ohio River Valley CO_2 Storage Project (2003 – 2007) and the non-DOE funded work associated with the design, construction, injection and storage of CO_2 from the PVF (2007 – 2011) to determine the feasibility of annually injecting and storing 1.5 million metric tons of captured CO_2 per year. Specific storage related activities within Phase I of the MT CCS II project included:

- The drilling of the Borrow Area (BA-02) characterization well, including geologic investigation and the formation testing within the well;
- Update of the regional geologic framework assessment;
- Preliminary reservoir modeling to evaluate design scenarios;
- Development of preliminary well configurations and monitoring plans; and
- Development of storage related costs to support development of the +/- 25% cost estimate for the entire project.

The drilling of the BA-02 characterization well, shown in Figure 12 and located about 2.5 miles from the Plant, provided data to further evaluate geologic and reservoir continuity in the broader area around the Plant so that the storage feasibility for the MT CCS II project could be determined. BA-02 was drilled on Mountaineer plant property in an area referred to as the borrow area; this area is located within the permitted confines of the plant's coal combustion by-products landfill. The location was chosen because it allowed an earlier start for the drilling operation than other candidate sites, which would need environmental permits. The BA-02 well was drilled from December 2010 through March 2011; hydrologic testing was conducted in the April-May 2011timeframe; and the analysis of data and final report writing was completed in the June-September 2011 timeframe. The other wells shown in Figure 12 are the PVF injection wells (AEP-1 & AEP-2) and deep monitoring wells (MW-1, MW-2 and MW-3).

This section of the report primarily addresses the front end engineering and design associated with the storage of CO_2. Discussions of the regional geologic framework and particulars related to the characterization activities and hydrologic testing performed on BA-02 are beyond the scope of this report. However, for those readers interested in the results from the characterization activities and hydrologic testing, a brief summary report, "Mountaineer CCS II Project: BA-02 Summary Characterization Report" is attached in Appendix A. The report: contains an introduction and background for the characterization work; addresses the preliminary reservoir delineation and ranking via wire-line, flow-meter and other analyses; discusses the overall results of the geologic analyses and reservoir testing; and it includes recommendations for future work that will serve to, among other things, further develop understanding of storage system, scope of further geologic characterization and feasibility of potential alternative well injection designs.

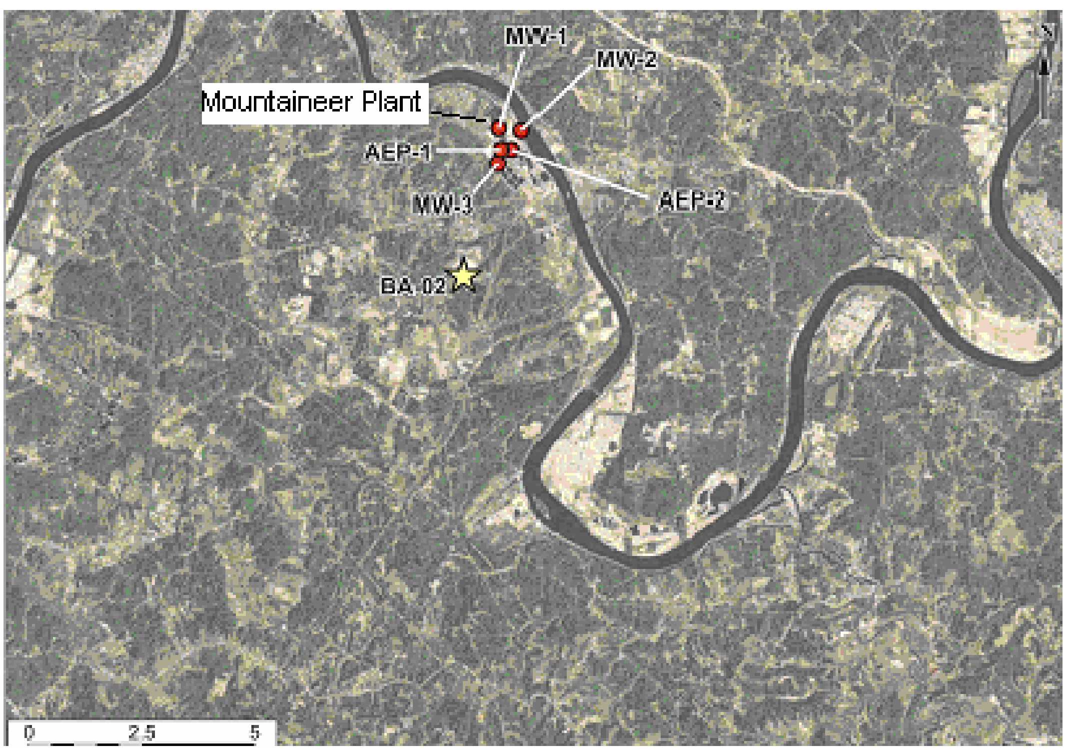


Figure 12 - Site Map for the Mountaineer Project

The system design discussions presented within this carbon storage section address: the selection of well injection sites; CO_2 transport pipelines, spanning their interface from the CO_2 compression system to the injection wells; and including the well injection and monitoring systems.

4.2.2 CO_2 Injection Sites

The selection of candidate well injection sites focused on: property owned by AEP in West Virginia, locations which required minimal right-of-way interferences for pipelines and access to the sites, and sites within relative close proximity to the Mountaineer plant. Based on the reservoir model simulations, the MT CCS II project developed a proposed layout of injection wells during the Phase I effort. Figure 13 shows the boundary of the Mountaineer power plant, the three AEP owned properties identified for the installation of injection and/or monitoring wells and the boundary of the modeled CO_2 footprint.

Again, with reference to Figure 13, the project team selected two injection well sites, BA-02 approximately 2.5 miles from the plant and Jordan Tract, approximately 10.5 miles from the plant. The injection well sites are denoted by yellow triangles. The Borrow area site is located within the property boundary of the Mountaineer plant site, as shown in a blue outline area. The Jordan tract site is shown in a red outlined area. Both proposed well injection sites are shown with estimated plume sizes, shown in yellow, extending in a 10,731 ft. radius from the wells. Additional discussion about the estimated plume size is contained in Section 4.2.4. The solid red triangles represent the proposed locations of deep monitoring wells within the Copper Ridge formation. The green and black triangles denote locations of intermediate monitoring wells. See section 4.2 for discussion about the monitoring well network.

The Sporn South site (since renamed Eastern Sporn) is shown between the Borrow and Jordan Tract sites; it is outlined in green and is considered a possible third well injection site. However, based on reservoir modeling simulations, the project team determined that a third injection site would not be needed. The site has however been designated a back-up injection well site from a project risk management standpoint, should either of the Borrow or Jordan injection sites not perform as expected.

Shown in Figure 14 is a detailed well design for the two planned injection wells. Based on the data from the PVF project, it was found that lower Copper Ridge formation has two distinct zones both of which can be used for sequestration. Thus, each injection well will have a dual completion, injecting into the upper and lower areas of the Copper Ridge Formation. The upper area of the Copper Ridge formation, designated Copper Ridge 1, is the primary zone of injection. The lower area of the Copper Ridge formation, designated Copper Ridge 2, is a secondary zone of injection. Because the higher-permeability Copper Ridge 1 zone overlies the lower-permeability Copper Ridge 2 zone, the majority of CO_2 will enter the Copper Ridge 1 zone. Additional information regarding the differences between the Copper Ridge Zones and their ability to receive injected CO_2 can be found in the Appendix A report, "Mountaineer CCS II Project: BA-02 Summary Characterization Report"

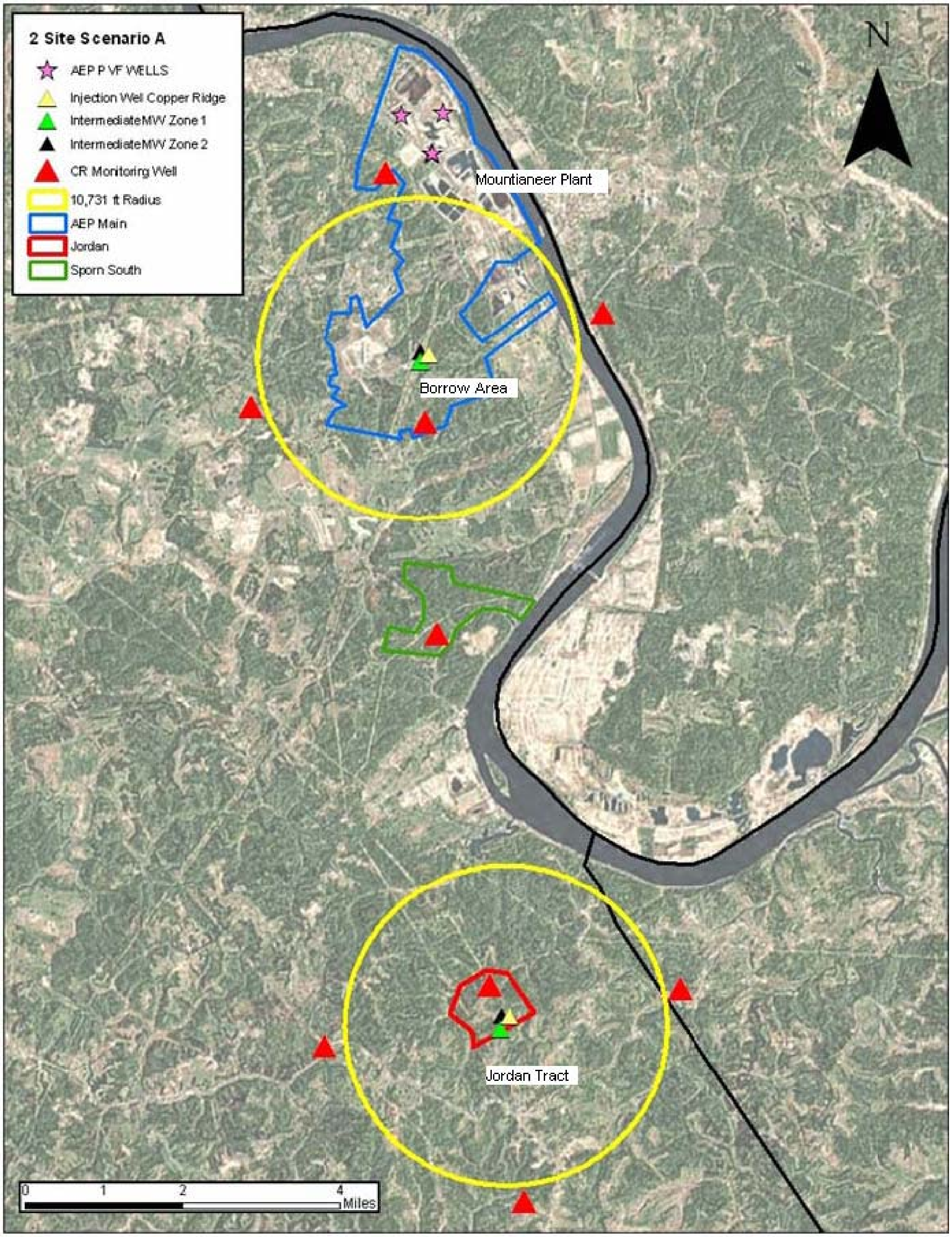


Figure 13 - Location of CO_2 Injection Wells, Monitoring Wells, Outline of AEP Property and the Estimated Plume Size

Detailed discussion regarding well design and methods and materials of construction for the injection and monitoring wells comprising the CO_2 storage system is contained in Sections 4.2.5 and 4.2.6.

Injection Well Design: Copper Ridge Formation

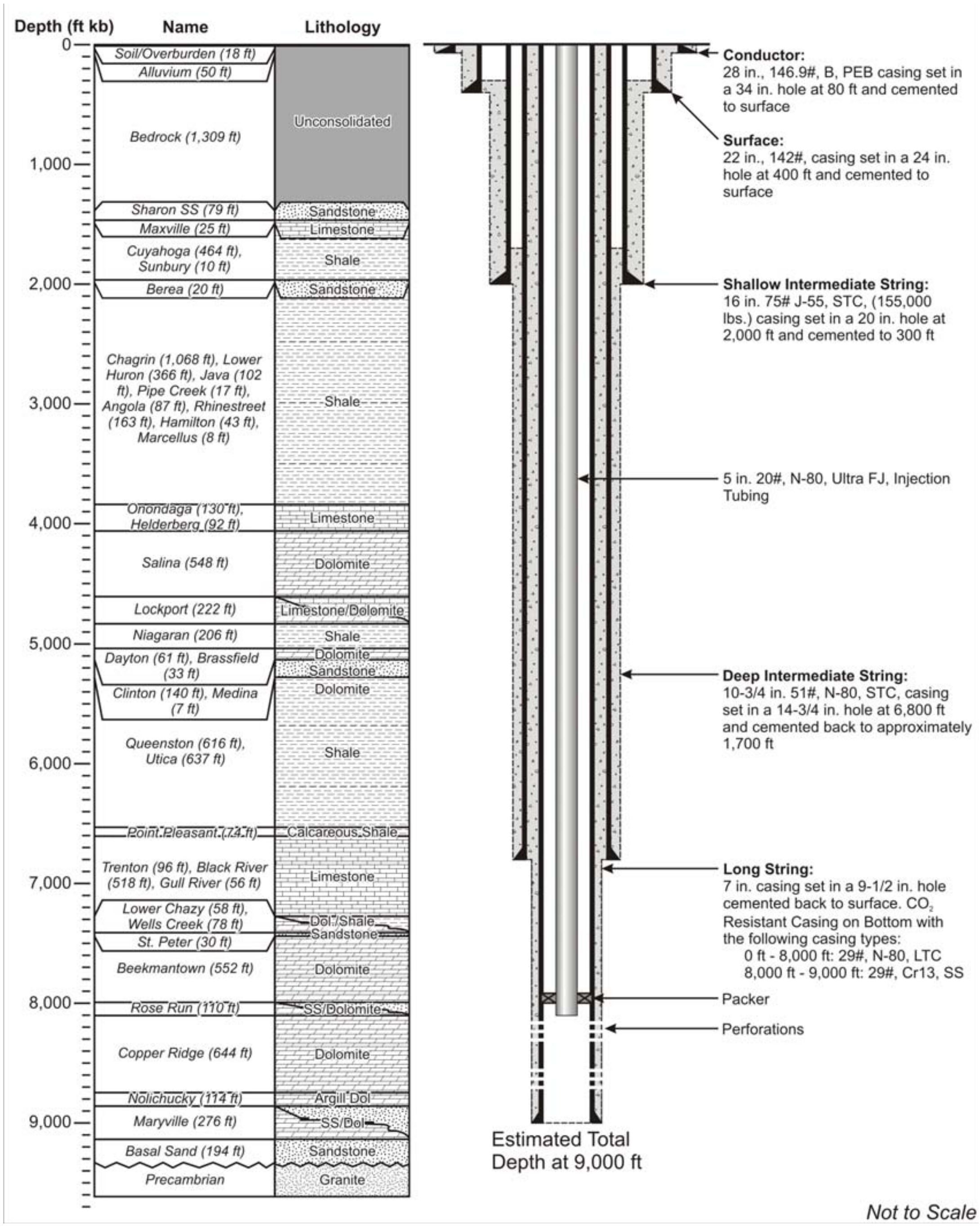


Figure 14 - Injection Well into Two Zones of the Copper Ridge Formation

4.2.3 Pipeline Routing

The CO_2 pipeline is designed to transport supercritical CO_2 from the CAP to the injection wells at BA-02 and Jordan Tract. This section identifies and/or summarizes:

- Proposed CO_2 pipeline routing,
- Pipeline technical specifications,
- Pipe interior lining,
- Pipe exterior coating,
- Pipe cathodic protection,
- Pipeline routing soil conditions for excavation, and
- Pipeline crossings

A pipeline routing and siting study was performed to identify proposed pipeline routes, characterize the soil conditions of the area in which the pipelines would be installed, identify any pipeline crossings, and develop technical specifications for the pipe, linings, coatings, and cathodic protection of the CO_2 transport pipeline for the MT CCS II project.

The pipelines were routed through AEP properties and transmission line corridors where possible to the BA-02 and Jordan Tract sites. WorleyParsons used USGS mapping to design potential pipeline routes and then walked each route to prepare the preliminary routing drawings.

With reference to the CO_2 Pipeline Plot Plan contained in Appendix C, supercritical CO_2 is pumped from the compressor building overhead on utility racks to an area beneath the Mountaineer Plant precipitators where it is routed in an open swale with the ash pipes across the plant to the south side. From this area the pipeline is routed above ground, supported from an existing gypsum conveyor (Gypsum Overland Conveyor No. 1), across Route 62 at the west end of the plant. The piping downstream of the CO_2 pump discharge is carbon steel, ASTM A106 Grade C, Schedule 160 in accordance with ASME B31.1, Power Piping. This section is above ground and is unlined, however, the standard schedule 160 used for this onsite portion includes corrosion allowance of 0.161 over the code required minimum wall thickness. The B31.1 piping code was applied since the piping was being routed through the plant site area with greater exposure to plant traffic and operations. At the point where the piping is supported from the gypsum conveyor the piping code transitions to ASME B31.4 since exposure to plant traffic is reduced and the pipe weight can be reduced for support from the existing conveyor. The pipe material is API 5L-X52 pipe with a wall thickness of 0.809 inch. This pipe section is provided with HDPE lining.

Shown in Figure 15 are the early pipeline corridors, located west of Route 62, that were considered for the Mountaineer CCS II project. Corridors are shown for four potential injections sites that originally included the Eastern Sporn site (originally known as the South Sporn site) and the Western Sporn site. With the selection of the BA-02 and Jordan tract injection sites, the Western Sporn site was dropped from further consideration. As previously noted, the Eastern Sporn site, is a designated back-up injection well site. The project, in its current form includes approximately 10 miles of pipeline located in corridors that access the BA-02 and Jordan Tract sites. The pipeline will be buried to a four foot depth.

The pipelines within the corridors are designed in accordance with ASME B31.4, "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids". The pipeline is 12-inch diameter API 5L-X65 with a wall thickness of 0.469. The pipeline is provided with an internal high density polyethylene (HDPE) lining and an external fusion bonded epoxy (FBE) coating. A flange is designed into to the pipeline every 1500 ft. for the purpose of pushing through the HDPE lining.

The pipeline will also receive cathodic protection in accordance with ASME B31.4/11 and 49 CFR 195. This will require that the pipeline be mechanically/electrically isolated from non-cathodically protected facilities, that temporary Cathodic Protection (CP) is provided until the permanent CP system(s) is available, and that the pipeline CP system performance meets the requirements of NACE SP0169.

A pig launcher is provided at the beginning of the pipeline west of Route 62 and a pig receiver is provided near the end of the pipeline at the Jordan Tract well site. Pigging is not provided for the pipeline branch to the BA-02 well site since this branch line is short. P&ID drawings for the pipelines described herein are also included in Appendix C.

The maximum operating conditions at the CO_2 Compressor Building are 3000 psig and 110^{o}F. The pipelines were designed to conditions of 3300 psig and 140^{o}F. All welds on the pipeline shall be 100% x-rayed to insure weld quality.

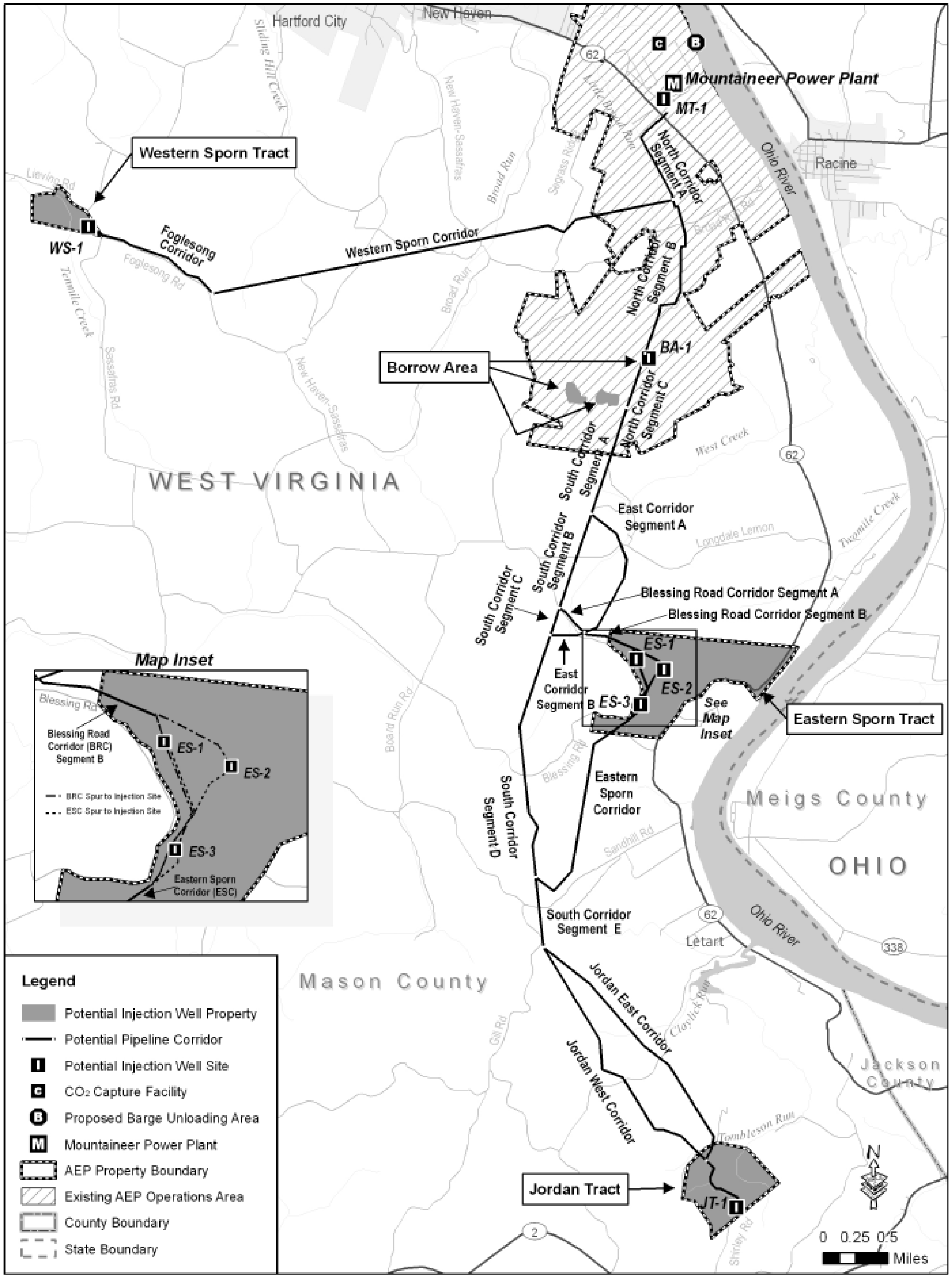


Figure 15 - Site Location for Pipeline and Injection Wells

4.2.4 Monitoring Verification and Accounting (MVA) Plans

4.2.4.1. Background and Overview

Given the UIC permit has not yet been issued for the project, the project team is taking the assumption that testing and monitoring requirements for the commercial-scale project will be similar to those for the PVF. The PVF project was authorized by West Virginia Department of Environmental Protection (WVDEP) UIC Permit No. 1189-08-53, as a Class V (experimental) permit. The Class V permit stipulates testing and monitoring requirements to verify that the experimental geologic sequestration project is operating as permitted and is not endangering USDW.

The project team has further assumed that the testing and monitoring requirements in the new Geologic Sequestration (GS) Rule will apply. The U.S. EPA, in December 2010, issued the GS Rule, which establishes a new class of injection well, Class VI, for wells that will be used to inject CO_2 into deep geologic formations for long-term storage (sequestration). The GS rule sets minimum federal technical criteria for Class VI wells for the purpose of protecting USDWs and mandates comprehensive monitoring of all aspects of well integrity, CO_2 injection and storage, and groundwater quality during the injection operation and the post-injection site care period. A Class VI UIC permit will be sought for the commercial-scale project; therefore, testing and monitoring requirements in the new GS Rule were considered in developing the testing and monitoring plan, scope of work and cost estimate.

Another driver for monitoring requirements is the Mandatory Reporting of Greenhouse Gases Rule (MRR) (74 FR 56260), which requires that all facilities that inject CO_2 for the purpose of long-term geologic sequestration to report basic information on CO_2 injected underground and imposes additional monitoring to quantify CO_2 emissions to the atmosphere.

A testing and monitoring program for the GS facility must be in place before the start of the active injection phase, which according to the original MT CCS II project plan would be sometime prior to September 2015 when operation would begin, and continues through the post-injection and site closure phase. The testing and monitoring program to be performed in the post-injection and site closure phase will be developed in Phase II. An anticipated monitoring schedule for a project having a 5-year active injection period is presented in Table 10.

The schedule and types of monitoring options, other than those required under the UIC permit, are subject to modification based on several factors, including field observations, site logistics, budgets, and potential lessons-learned at this site and others. Pre-injection monitoring is required to characterize baseline conditions that could be affected by the injected CO_2. The duration and complexity of pre-injection monitoring varies by monitoring method. For some of the monitoring techniques (e.g., Pulsed Neutron Capture logging), a single sampling event (or survey) will be sufficient to characterize pre-injection conditions. For others, such as USDW groundwater monitoring, the baseline sampling program includes multiple sampling events across seasons to characterize variability in the target analytical parameters that will be monitored.

Monitoring and Testing Methods	Base-line	Active Injection Phase				
		Year 1	Year 2	Year 3	Year 4	Year 5
Quarterly sampling and analysis of the CO_2 injection fluid	NA	X X X X	X X X X	X X X X	X X X X	X X X X
Monitoring of injection rate volume, pressure, and temperature; annulus pressure and annulus fluid volume	NA	Continuous				
Corrosion monitoring of well materials	NA	X X X X	X X X X	X X X X	X X X X	X X X X
External mechanical integrity testing (MIT)	X	X	X	X	X	X
Pressure Fall-Off Testing	NA	X	X	X	X	X
USDW aquifer groundwater monitoring	≥1 year (quarterly)	X X X X	X X X X	X X X X	X X X X	X X X X
Groundwater quality and pressure monitoring in Intermediate Zone(s)	X	X	X	X	X	X
Microseismic Monitoring for Injection Induced Fracturing	≥1 month	Continuous				
PNC and other Wireline Logging for CO_2 Detection	X	X	X	X	X	X
Injection Reservoir Fluid Chemistry Monitoring	X	X	X	X	X	X
Injection Reservoir Pressure Monitoring	≥3 months	Continuous				
Modeling	X	X	X	X	X	X
Surface emissions monitoring	1 to 2 years[a]	X X X X	X X X X	X X X X	X X X X	X X X X

X: represents single sampling/survey event.
a. Quarterly or monthly frequency

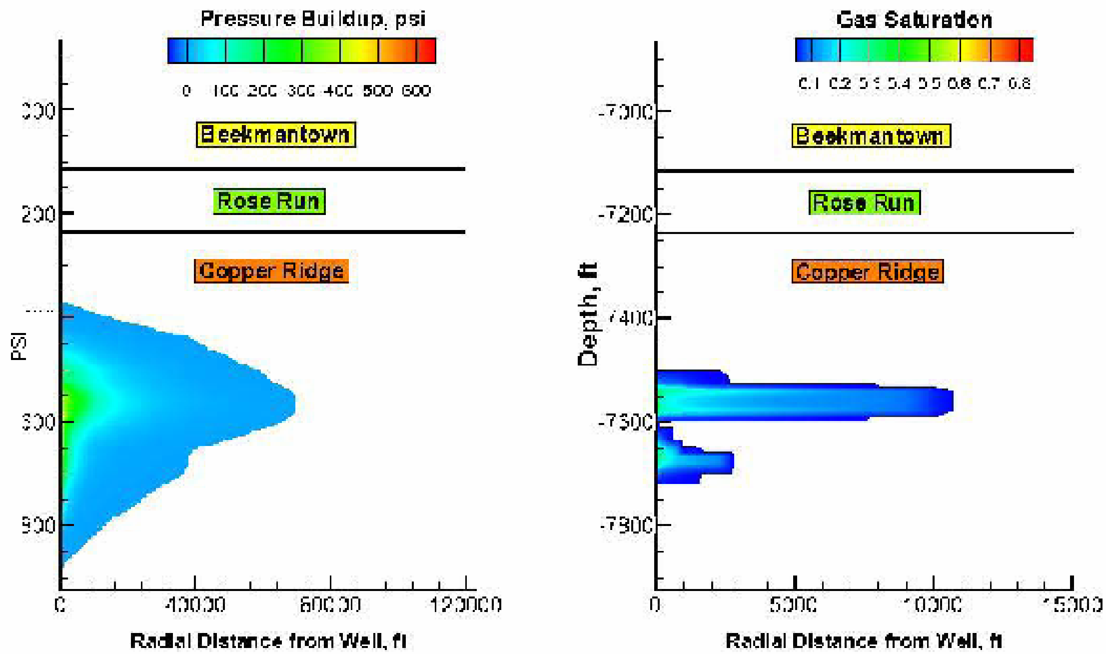
Table 10 - Geologic Monitoring Plan for CCS II

4.2.4.2. Monitoring Plan

Based on PVF experience, the primary monitoring technique for plume detection and management will be pressure monitoring (at injection wells and deep monitoring wells). Geochemical sampling at the deep wells is expected to provide the field evidence of CO_2 break through in the well. Most of the available geophysical monitoring techniques (such as cross well seismic or repeat surface seismic) will not be feasible at this site because the reservoirs are thin and cannot be resolved in the seismic data.

Over a five year operating life of the MT CCS II project, up to 7.5 million metric tons of CO_2 may be injected with one-half the amount targeted for injection in each of the injection wells. Based on modeling performed to date, and illustrated in Figure 16, estimated plume size radius (10,700 ft) and pressure affected areas (70,000 ft) have been determined for the injection wells (based on a saturation curtailed at 0.1 and a pressure front at 1psi.). As an additional point of note, the static geologic model used for the reservoir simulation on MT CCS II is based on the data obtained from the PVF project.

One of the main assumptions of the modeling is that the geology at Borrow area and at Jordan tract are the same as that of the PVF site.



(a) **(b)**

Figure 16 – Simulated Cross Section of (a) Pressure Front and (b) CO_2 Plume in Copper Ridge after Five Years of Injection

Based upon the recently issued UIC Class VI guidelines, the project developed a proposed monitoring plan and layout. With reference once again to Figure 13, the monitoring plan calls for the installation of nine deep monitoring wells and four intermediate monitoring wells (Figure 13 does not include shallow groundwater monitoring wells or microseismic monitoring wells).

The primary monitoring technique for plume detection and management will be pressure monitoring (at injection wells and deep monitoring wells). Geochemical sampling at the deep wells is expected to provide the field evidence of CO_2 break through in the well. The intermediate monitoring wells are assumed requirements based on the new UIC guidelines provided by the US-EPA for CO_2 sequestration. Most of the available geophysical monitoring techniques (such as cross well seismic or repeat surface seismic) will not be feasible at this site because the reservoirs are thin and cannot be resolved in the seismic data.

For the readers of this report that have a greater interest in more detailed discussion and treatment of preliminary monitoring plans, please see the report, "Preliminary Monitoring Plan for the AEP Commercial Scale Project," attached as Appendix B.

4.2.5 Injection and Monitoring Well Design

The injection and monitoring wells for the Mountaineer CCS II Project are designed for the injection and monitoring of the CO_2 plume and pressure front during and after injection. An injection well, as its name infers, is primarily used for injection of CO_2 into the target storage reservoir. A monitoring well will be used for monitoring the storage reservoir and the fate of the injected CO_2**.** This type of well may or may not be completed into the storage reservoir.

Proper well design and use of appropriate injection equipment, monitoring tools, and sampling equipment protects the underground sources of drinking water (USDW) from contamination during drilling and operation of the wells. The injection and monitoring well designs for the Mountaineer CCS II project were prepared by Battelle for AEP, and were built on the experience of the previous deep wells which were drilled in this area and the injection system that was operated for 18 months at the PVF. Proper well design protects the USDW from contamination during drilling and operations and enables the use of the appropriate injection equipment, monitoring tools and sampling equipment. The selection of proper casing diameters and weights, and the design of the cement system help to ensure that well integrity will be maintained for the operating lives of the injection and monitoring wells.

In addition to the detailed well design for the two deep Copper Ridge formation injection wells (Figure 14), two types of deep monitoring and intermediate monitoring wells are planned for the Mountaineer CCS II project. The monitoring wells are shown in shown in Figures 17 through 20, along with the corresponding lithology. With reference to Figure 13, showing the locations and types of monitoring wells, the deep monitoring wells will be drilled to penetrate the injection zone(s) at distances of approximately 2,500 ft. and 11,000 ft. from the injection well. Each deep monitoring well will be designed to monitor a single zone. For dual zone monitoring, larger diameter bore holes and casing strings are required to accommodate equipment for monitoring two zones of injection, should this type of monitoring be employed. The intermediate monitoring wells, one penetrating the Berea Sandstone and one penetrating the Clinton Sandstone formations will be drilled at each of the two injection well drill sites.

In terms of design and materials of construction, injection and monitoring wells both have multiple casing designs; the injection wells do however have redundant cement/grout layers between the casings in the conductor, surface, shallow and deep intermediate sections. The surface, shallow, intermediate and top portion of the deep casing strings for the Mountaineer CCS II injection wells will be comprised of suitable carbon steel. Unlike the monitoring well casing design, the bottom 1000ft of the long string casing in the injection well will be comprised of a HP1-13Cr or HP2-13Cr or similar casing grades. This casing may be subjected to wet and dry conditions during injection cycles involving contact with a brine solution void of inhibitors and oxygen scavengers, and therefore will be comprised of at least 3% nickel to protect the stainless steel from chloride attacks.

The cementing plan for the inner most casing string (long string casing) is different for the injection well and the monitoring well. The long string casing will be cemented all the way up to the surface for the injection well but for the monitoring well the long string casing will be cemented up to the end of the previous casing string (~6000ft from the surface).

The injection tubing should be comprised of a carbon steel alloy, such as L-80 grade; this grade alloy is suitable as the injection tubing will be removed from the well at least annually during well workovers. The tubing for the monitoring wells will be completed with standard carbon steel in most circumstances.

<u>Dual Zone, Deep Monitoring Well Design</u>

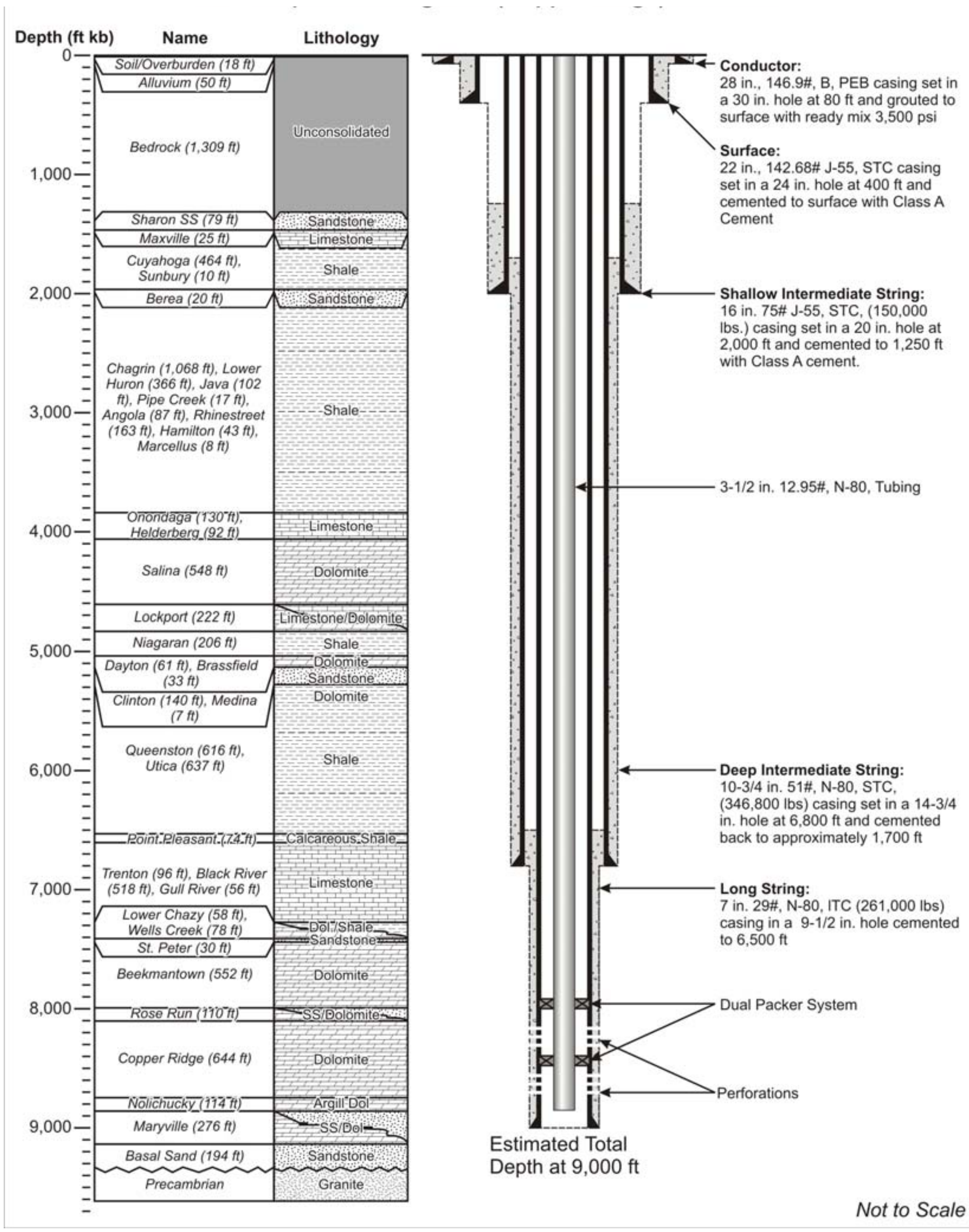


Figure 17 - Dual Zone, Deep Monitoring Well in the Copper Ridge Formation

Single zone, Deep Monitoring Well Design

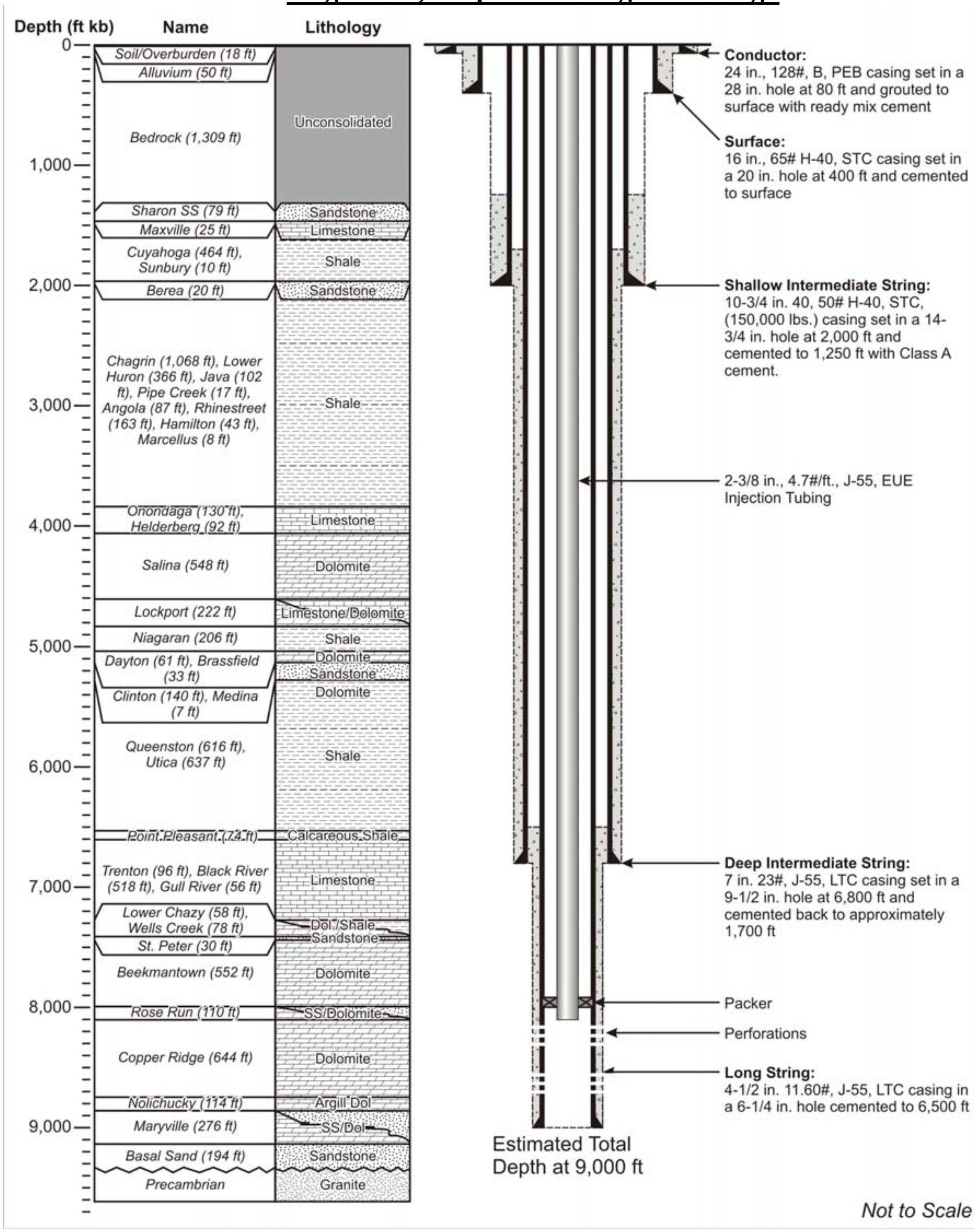


Figure 18 - Single Zone, Deep Monitoring Well in the Copper Ridge Formation

Intermediate Monitoring Well Design

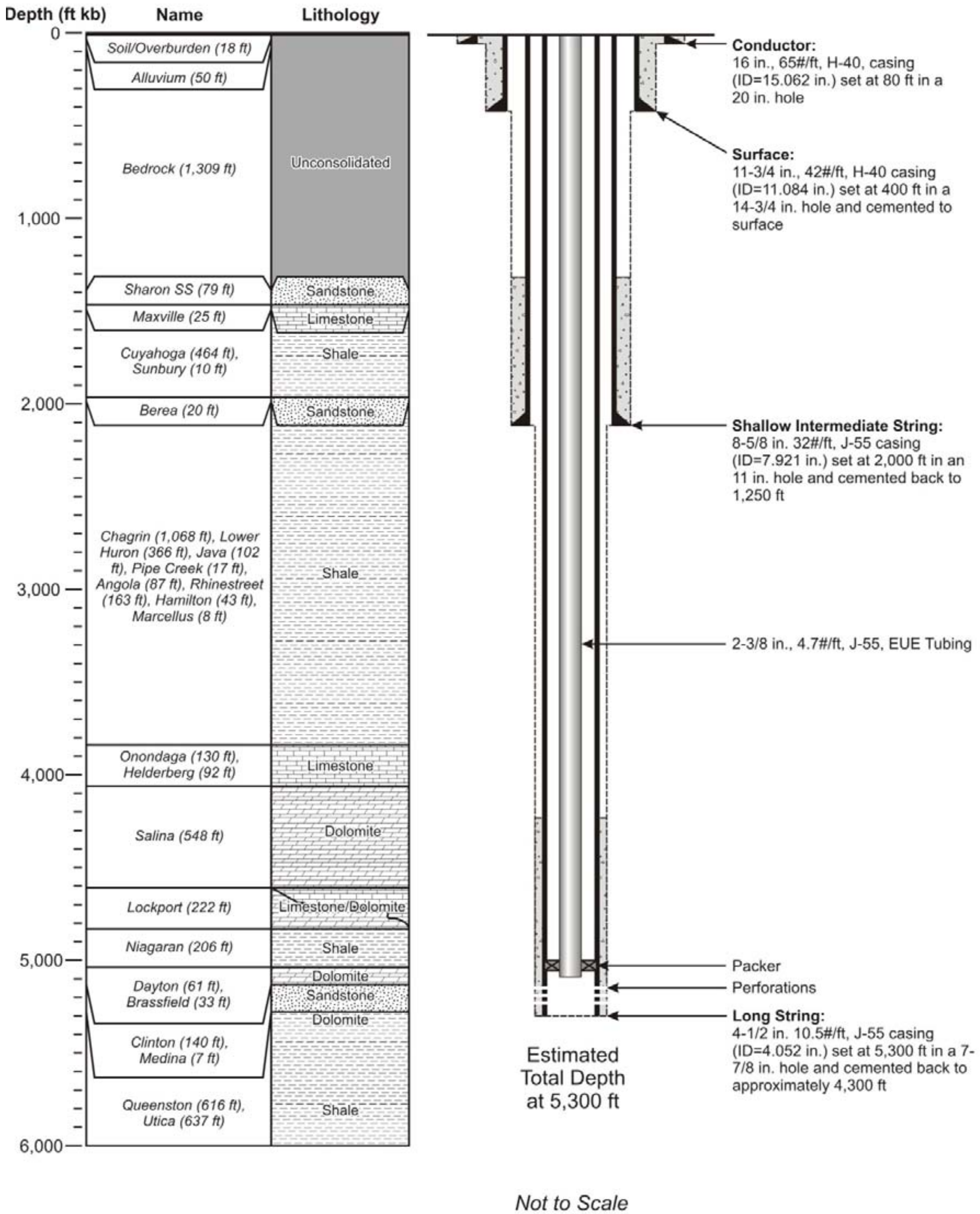


Figure 19 - Intermediate Monitoring Well in the Clinton Sandstone

Intermediate Monitoring Well Design

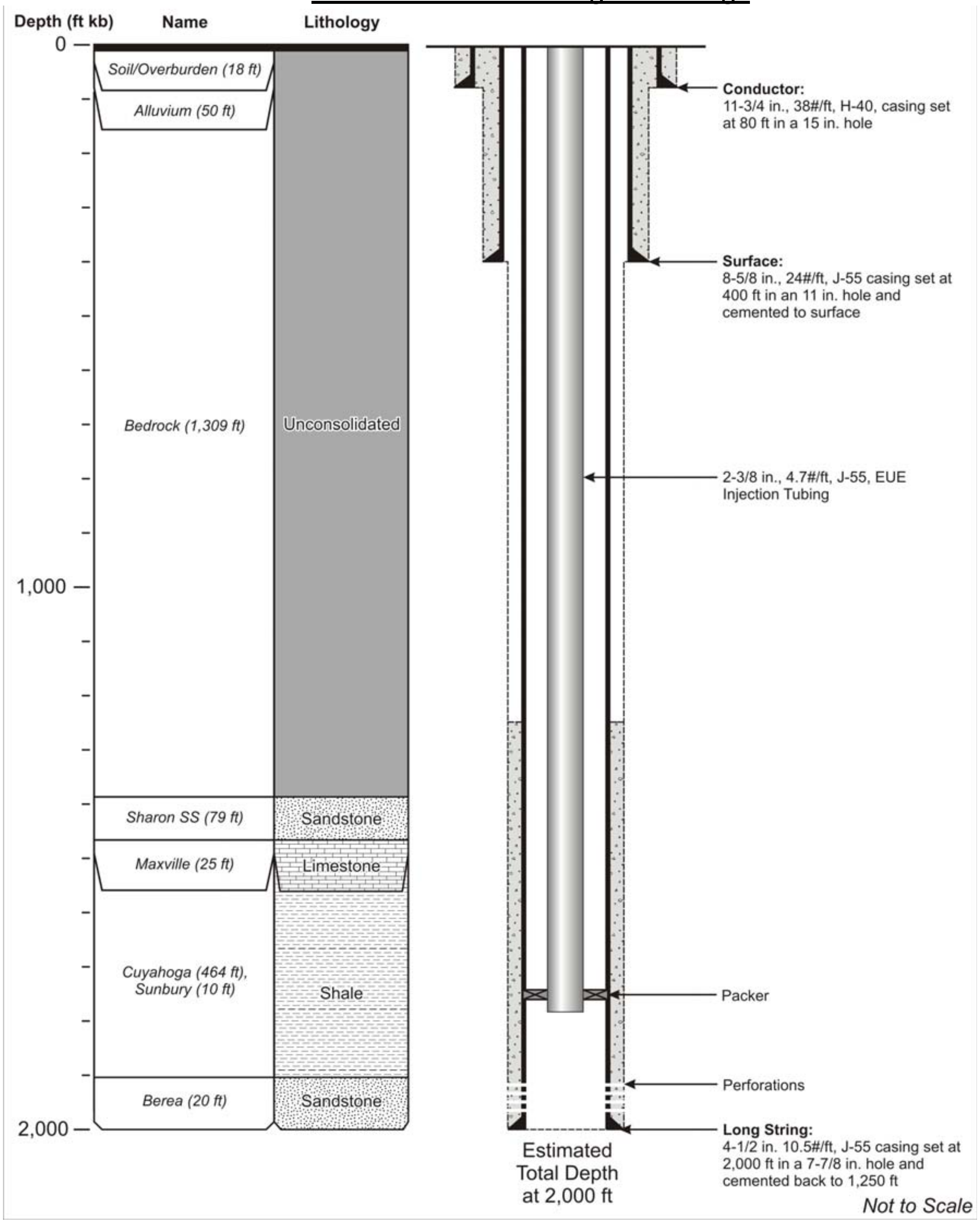


Figure 20 - Intermediate Monitoring Well in the Berea Sandstone

4.2.6 Methods and Materials of Construction

4.2.6.1. Casing Design and Construction

As shown in the well design figures, several types of materials are used. While these designs and specifications were carefully engineered, actual casing grades, weights and setting depths may vary based on actual well conditions encountered and future availability of materials.

The conductor casing is the first casing to be inserted into the well bore hole, and is set through the unconsolidated soils, sands and gravels and into the bedrock to keep the unconsolidated zones stable while the hole is drilled to deeper depths. Plans are to set the conductor casing, regardless of well design, at approximately 80 ft. The 24" and 26" casing manufactured for natural gas pipeline service meets all of the specification requirements necessary for use as conductor casing for the wells. The ends of the casing are plain with a machined bevel for butt-welding. The casing will be lowered into the bore hole one joint at a time and welded together on the rig floor by a certified welder. The conductor casing will be cemented back to the surface with a 3500 psi cement-grout mixture.

Following the conductor casing, the surface casing is installed to protect the fresh water aquifers from contamination during the drilling, injection and monitoring processes. Plans are to set the surface casing, regardless of well design, to approximately 400 ft. A guide shoe will be installed on the bottom joint of the surface casing to help guide the casing into the hole to the desired setting depth. Casing centralizers will be installed to maintain casing stand-off from the bore hole to ensure a good sheath of cement around the entire diameter of the casing. Each threaded connection will be coated with API approved, high pressure modified thread compound. Each threaded connection will be made up to the API recommended torque with power tongs. The surface casing will be cemented from the 400 ft depth back to the surface.

The shallow intermediate casing will be run through the Berea sandstone formation to seal off any natural gas, oil and water so that the next section of the well can be drilled on air. It is planned to set shallow intermediate casing, regardless of well design, at approximately 2,000 ft. A casing guide shoe will be installed on the bottom joint of shallow intermediate casing to help guide the casing into the hole to the desired setting depth. Casing centralizers will be installed to maintain casing stand-off from the bore hole to ensure a good sheath of cement around the entire diameter of the casing. Each threaded connection will be coated with API approved, high pressure modified thread compound, and will be made up to the recommended torque with power tongs. The shallow intermediate casing will be cemented back to approximately 300ft from the surface. Note that shallow intermediate casing will not be run for the intermediate Berea monitoring well.

The deep intermediate casing will be run through the Queenston/Utica shale section so that the well can be drilled to total depth without fear of deteriorating well bore conditions (e.g. sloughing, lost circulation and/or cave-ins). The deep intermediate casing will be run on the deep monitoring wells and the injection wells to a depth of approximately 6,800 ft. Casing centralizers will be installed to maintain casing stand-off from the bore hole to ensure a good sheath of cement around the entire diameter of the casing. Each threaded connection will be coated with API approved, high pressure modified thread compound and made up to the recommended torque with power tongs. The deep intermediate casing will be cemented back to approximately 3300 ft. or 300 ft. inside the shallow intermediate casing. Deep intermediate casing will not be run on the intermediate Berea monitoring wells or the intermediate Clinton monitoring wells.

The longstring casing is the deepest casing to be installed on the wells. The longstring is set through the zone(s) of interest, cemented and then perforated across the zone(s) of interest to establish communication with the zone(s) for injection or monitoring purposes. The longstring setting depth will vary depending upon the purpose of the well. The bottom ~1,000 ft of the longstring casing of the injection well will be a CO_2 corrosion-resistant stainless steel. A guide/float shoe will be installed on the bottom joint of longstring casing to help guide the casing in the hole to the desired setting depth. The float acts as a positive seal once cement is placed in the well bore to reduce the chance of the cement “u-tubing” due to the differential pressure. Casing centralizers will be installed to maintain casing stand-off from the bore hole to ensure a good sheath of cement around the entire diameter of the casing. Longstring casing on the injection wells will be cemented by circulating cement back to the surface in one or more stages. Each threaded connection will be coated with API approved, high pressure modified thread compound and made up to the recommended torque with power tongs.

4.2.6.2. Well Cementing

Oilfield cement, for cementing the well casings in place, will be delivered to the well site in dry bulk form in pneumatic trucks. The dry bulk will be mixed with the proper type and amount of dry additives at the cementing service company’s dry bulk mixing facility.

Once on location, the dry cement mixture will be transported to the mix/pump truck via compressed air and mixed with the proper amount of water. The cement slurry density will be monitored with densitometers and when it reaches the correct slurry density, it will be transferred to high pressure pumps and pumped down the casing. The cement will be pumped out the bottom of the casing and up the casing annulus until it reaches the desired height in the annulus. Mixing rates and displacement rates will vary from well to well depending upon pump pressure, casing depth, cement type and volume and thickening time. The most common oilfield cement used in the Appalachian basin is standard Portland Class A. Additives are determined as a percent of weight of the dry bulk cement or of the weight of the mix water, depending upon the additive. Cement thickening times and compressive strengths are obtained through laboratory testing. Most of the common cement blends have published thickening times and compressive strengths but less common, custom cement blends require laboratory testing on an individual basis.

Although these schedules and specifications were carefully engineered, actual casing setting depths, cement types, additives and volumes may vary based on actual well conditions encountered at site. Note that there will be multiple concentric cementing activities and the inner most cement (the cement for the long string casing, see Figure 14) will be mixed with additives, as per industry standards, to make the cement acid resistant.

4.2.7 Controls Logic and Philosophy

The carbon storage system will be controlled by Mountaineer's Distributed Control System (DCS) located inside the plant boundaries of the Mountaineer plant. The DCS performs all of the monitoring and control of the CCS processes with the exception of complex equipment (e.g., CO_2 Compressor) which is controlled by dedicated local programmable logic controllers (PLC). For complex equipment the DCS performs high level control functions and serves as the operator interface to operate and monitor the equipment.

Each injection well is instrumented, monitored, and controlled by the Well Maintenance and Monitoring System (WMMS) located at each well site. The WMMS is a PLC that communicates with the DCS back at the plant via a fiber optic data link; the fiber optic cable runs back to the plant along side the pipeline. To minimize the potential for security breaches in the CCS control system, communication between the well site and the DCS will be constrained to primarily monitoring signals. A minimal number of signals will be sent from the DCS to the WWMS to coordinate the injection wells with the performance of the chilled ammonia process (CAP) at the Mountaineer plant.

The WMMS provides protection features at the well site that are independent of the DCS. Each injection well has two (2) motor operated isolation valves and one (1) flow control valve with an Electro-hydraulic Control operator. These valves are controlled by the WMMS during operation. The CO_2 pump is controlled by a Variable Frequency Drive (VFD). The VFD receives a signal from the DCS to adjust speed of the pump to maintain the desired flow into the injection well(s).

4.2.7.1. CO_2 Pump and Pipeline Control

Preliminary control logic and DCS integration for CO_2 transport and injection is described below. This information was developed as a basis for the Phase I conceptual design, and is likely to be further evaluated and optimized in Phase II when detailed controls logic, alarms, interlock protection schemes, and communications protocols are developed.

The CO_2 pump will be operated by the DCS. The DCS provides Operator Interface Terminals (OIT) to start and stop the CO_2 transport pump, and graphic displays providing process information. The operator determines a flow set point for the CO_2 product exiting the Mountaineer plant through the transport pipeline. This set point will be determined based on injection well pressure and CAP CO_2 production, as well as on the number of injection wells in service. The DCS will control the pump VFD which will adjust pump speed to maintain the required pipeline flow.

The DCS also monitors the liquid CO_2 drum level. This level signal provides a bias to the flow control loop to adjust the pump speed up or down as required to maintain a predetermined level in the drum. The drum level bias will not be active during startup and shutdown.

The operator determines a flow set point for the CO_2 to be injected into the well. The DCS will send a signal to the well site WMMS based on this value. The flow set point will be used by the WMMS as the set point for the injection well control valve. Flow control at the injection well site will be closed loop using feedback from the injection well flow monitor to determine deviation from the set point received from the DCS. In the event that communication from the DCS is lost, the WMMS will maintain the control valve flow at the last received set point provided the injection well continues to operate within the normal operating parameters allowed by the WMMS.

If only one well is being used for CO_2 injection, the set point for the injection well control valve will be chosen to drive the control valve full open. This will allow the VFD driven CO_2 pump to perform all control required. If more than one well is being used, a flow set point will be set for one injection well control valve and the control valve for the second well will set to the full open position. In this configuration, flow to the first well will be controlled by the flow set point in the WMMS and the balance of the CO_2 to the second well will be controlled by the output from the CO_2 pump.

The DCS will send a shutdown signal to the WMMS when the operator determines that injection is no longer required and initiates a shutdown sequence, or in the event of an emergency CAP shutdown. Upon receipt of the shutdown signal, the MWWS will close the flow control and isolation valves to stop the injection of CO_2.

The DCS will also monitor process conditions, alarm Operations personnel as necessary of abnormal operating conditions related to the transport and storage systems, and initiate CO_2 pump shutdown as required preventing pump damage.

4.2.7.2. WMMS Operation

The MT CCS II WMMS hardware and software will be similar in design to the hardware and software used on the PVF project. A single processor Allen Bradley (Rockwell Automation) ControlLogix PLC with type 1756 I/O modules and a local human-machine -interface (HMI) will be used for each well site. The PLC and instrumentation will be powered by an uninterruptable power supply (UPS) sized to run for 24 hours in the event of a power outage with the intent of providing uninterrupted data until a portable generator can be brought on line at the well site. Redundant power supplies will be used for the processor and for direct current (DC) instrument power. The PLC will be networked to the Mountaineer Plant control room via fiber optic Ethernet. The local HMI will communicate with the PLC and be used for diagnostics and trouble-shooting.

The WMMS system will automatically control accumulator level and tank operation to provide pressure control of the annular fluid. Annular fluid is brine used to fill in the annular space between the injection tube and the long string casing. The UIC rule requires the annual fluid must be maintained at a higher pressure than the injection pressure. Maximum pressure will be controlled by bleeding off the annular fluid through a back-pressure control valve. Various pressure increments will cycle the pumps on and off. Control room operators will monitor operation data and receive alarms from the well site PLC. The nitrogen side of the accumulator will be filled and adjusted to reach the maximum operating pressure at 50% full. Nitrogen is used to control any leaks in the system, which are unexpected. Thus, the need for backup nitrogen cylinders will be minimized.

Pending further review during the detailed design process, the alarm conditions for the WMMS are listed below. More than one alarm point may be used for each category: low fluid annular pressure, low fluid annular temperature, low accumulator level, high accumulator level, low storage tank level, high injection point pressure, pump fault, valve fault, and/ or low nitrogen pressure.

The WMMS will be designed for fail-safe operation whereas a loss of power or control signal to critical valves will cause the valves to close. Default I/O states will be programmed into the PLC and will be set to fault in a safe position in the event of a processor fault or if the controller is offline. A PLC interlock will automatically close the wellhead valves if (a) Annular fluid pressure drops below the allowable limit (injection pressure + 50 psig), or (b) Injection pressure exceeds the allowable limit (TBD - dependent on geological characteristics).

5.0 Project Estimate

As one the main deliverables for the Phase I scope of work, DOE tasked AEP and the project team to develop a +/- 25% cost estimate for the entire project, no later than ninety days before the end of Phase I or by June 30, 2011. The estimate that was developed included all in project costs for: Phase II Detailed Engineering/Design & Permitting, Phase III Construction & Start-up, and Phase IV Operations. In addition to the Phase I cost estimate, AEP and the project team would have been required to further refine the +/- 25% cost estimate to a +/- 10% cost estimate within ninety days of the end of Phase II, or by September 30, 2012.

5.1 Approach

The project team approached the development of the cost estimate as a collaborative effort involving team members from: AEP, Alstom, Battelle, and Worley Parsons (hereinafter referred to as the entities). Early in Phase I, a kick-off meeting was held with all entities contributing to the final estimate. The purpose of the meeting was to inform participants of the various common aspects of the estimate and expectations. This initial meeting was followed up with bi-weekly meetings to: discuss progress in completing deliverables, identify timing obstacles, and make decisions to resolve issues.

The estimate was developed using a detailed Work Breakdown Structure (WBS) format that established and progressively delineated the project between and within the Capture and Storage sections of the project. The sections were further broken down to component systems and basic construction categories. The WBS evolved with the addition and changes in scope and each WBS was defined to determine what was to be included within each. The following factors were initiated and/or agreed to in advance of the estimate development and contributed to the successful compilation of the overall project estimate:

- Shared Responsibility – A matrix by WBS was published to all entities showing who supplied the quantities, material costs, labor cost and input to the consolidated estimate.
- Common Estimate Format and Template - The estimate format and template was compatible with the estimating systems of all the entities and easily consolidated into a master estimate.
- Common Coding – All entities used an agreed to estimate source coding that was developed for contracting strategy, escalation and risk factors applicable to individual line items.
- Jointly Developed Labor Unit Rates, Crews, Productivity Factors and Indirect Costs – As a result of numerous early meetings, agreement was established for uniform application of these components to the estimate.
- Collaborative Development of Escalation Factors – A composite escalation forecast was developed based on inputs by the entities (internal and external source inputs) for several high level categories such as: type of work, commodities, equipment and services. A table was developed and applied consistently with respect to the project execution schedule.
- Use of a 3-D model – Estimated quantities for the capture system were based on the model. All large bore piping 2-1/2 inches and above was accounted for in the model.
- Use of Budgetary Quotes – Budgetary quotes were obtained for over 95% of major equipment/material costs.
- Inclusion of Experienced Construction Personnel - Several meetings and discussions along with input from an erection contractor were utilized to focus on constructability of system components including delivery, on-site handling, erection and sequencing. Numerous opportunities and/or recommendations, raised by construction personnel were incorporated into the fabrication and estimated costs for components.

Once all the estimate inputs were received, several red team type review meetings (challenging, thoughtful and probing meeting discussions between a project team and a group of knowledgeable colleagues and peers) were held among the entities to review the estimate by individual WBS to determine if there were any omissions, changes or deletions based the current scope and also to validate the reasonableness of various items.

The front-end engineering and design was performed to support a bottom up approach for development of the estimate. AEP estimates that the project team expended between 10 –

15 % of all forecasted engineering hours in the development of the estimate. The overall thoroughness in executing the estimate resulted in a product that exceeded the anticipated +/- 25% accuracy and was complimented on by DOE's consultant as "the best estimate they had seen in the 19 years of working with the DOE".

5.2 Overnight Cost

The overnight project cost (i.e. the yet-to-be escalated project cost to account for future year spending) was built based on adhering the phased project approach agreed to between AEP and DOE, a 26 month construction schedule, a five days per week - eight hours per day work week, and owner election to use a multi-prime construction contracting approach (Figure 21).

ID	Task Name	Start	Finish
1	Phase II - Detailed Engineering/ Design & Permitting	10/3/11	10/24/14
2	Phase II - Detailed Engineering/ Design & Permitting	10/3/11	12/31/12
3	Engineering/ Deisgn	10/3/11	10/24/14
4	CAP System Engineering & Design	10/3/11	4/14/14
5	Mechanical Engineering & Design	11/4/11	10/24/14
6	Start Mechanical Equipment Fabrication	8/13/12	8/13/12
7	Electrical/ I&C Systems Engineering & Design	8/20/12	2/3/14
8	Permitting	6/4/12	12/31/13
9	COE 404/401 Permit	6/4/12	5/2/13
10	UIC Permit	11/28/12	12/31/13
11	Long-lead Procurement Vendor Engineering & Fabrication	4/19/12	3/21/14
12	Structured Packing (Absorber & Regenerator vessels)	4/19/12	8/29/13
13	CO2 Compression System	8/20/12	3/21/14
14	Shell & Tube Heat Exchangers	8/13/12	2/28/14
15	Recirculation Pumps	8/16/12	3/5/14
16	Plate & Frame Heat Exchangers	9/4/12	2/28/14
17	Refrigerant Evaporative Condensers	8/13/12	2/10/14
18	Refrigeration Compressors	9/4/12	2/10/14
19	Phase III - Construction & Start-up	1/2/13	8/31/15
20	Phase III - Construction & Start-up	1/2/13	8/31/15
21	Capture System Construction	1/25/13	8/26/15
22	Capture System Site Prep	1/25/13	4/4/13
23	Award Civil/ Structural Package A	5/8/13	5/8/13
24	Award Civil/ Structural Package B	11/26/13	11/26/13
25	Civil/ Site Construction	5/9/13	3/18/14
26	Structural/ Mechanical Construction	10/29/13	12/16/14
27	Electrical/ I&C Construction	4/11/14	2/11/15
28	Capture System Commissioning	9/17/14	8/6/15
29	Mechanical Completion	2/11/15	2/11/15
30	Fine Tuning	6/2/15	8/26/15
31	Storage System Construction	1/30/13	8/3/15
32	Monitoring Well Site Prep	1/30/13	4/24/13
33	Monitoring Well Construction	5/3/13	8/3/15
34	Injection Well Site Prep	1/17/14	5/22/14
35	Injection Well Construction	1/2/14	8/19/14
36	Pipeline Construction	1/31/14	2/17/15
37	Pipeline Hydrotest	9/15/14	9/29/14
38	Storage System Commissioning	2/17/15	7/2/15
39	Phase IV - Operations	9/1/15	6/28/19

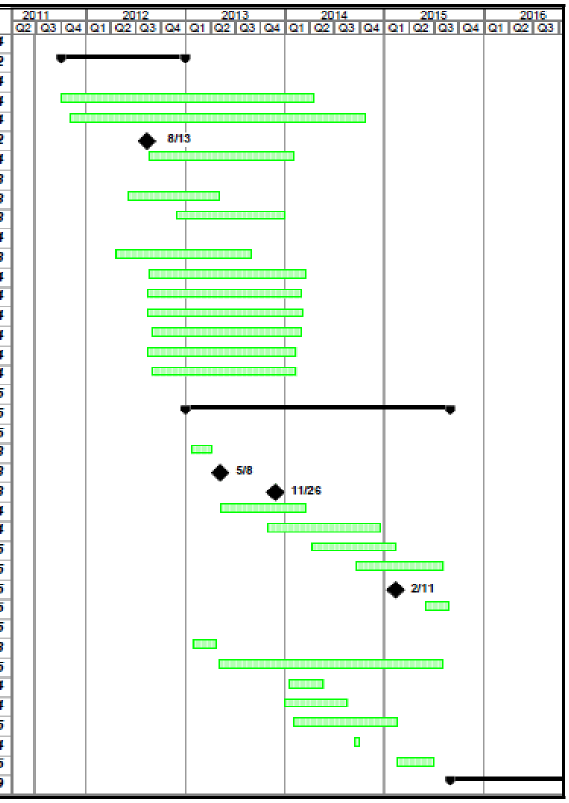


Figure 21 – Key Project Milestones & Activities

With reference to Figure 21, the scope of the overnight cost estimate includes the engineering, procurement, construction, start-up and fine tuning of the carbon capture and storage system retrofit systems; the scope of the overnight cost does not include costs for system operations in Phase IV. Detailed engineering to support permitting activities and ordering of long lead procurements would take place during Phase II. Detailed engineering to support evaluation and award of mechanical and electrical/instrumentation & controls packages would flow into Phase III construction. Phase IV operations costs are included in the overall project costs, noted in Section 5.5.

Major quantities associated with the estimate are shown below in Table 11. The quantities have not been subject to a detailed optimization review and are likely conservative from an Owner's risk management perspective. Due to the tight Phase I schedule and the need to compile/deliver the cost estimate to DOE 90 days prior to the end of Phase I, sufficient time was not available to the project team to refine the estimated quantities. However, based on the red team reviews by the entities in compiling the estimate, a number of opportunities for saving were identified for further evaluation in Phase II.

Capture System			**Storage System**	
Chilled Ammonia Process Equip., Tie-in Duct, Storage Tanks, Buildings and Compression Equip.			**Wells**	
80,000 cy.	Concrete		2	Injection Wells
9,500 tons	Structural Steel		9	Deep Monitoring Wells
118,000 ft.	Piping		4	Intermediate Monitoring Wells
127,000 ft.	Conduit/Cable Tray		8	Groundwater Monitoring Wells
1.2-MM ft.	Electrical Cable		**Pipeline**	
			10 mi.	CO_2 Transport Pipeline

Table 11 – Major Material/Equipment Quantities in Capture & Storage Systems

The calculated overnight costs for the Capture and Storage systems are shown below in Table 12. The figures shown in Table 12 do not include any contingency, nor do they have any risk allocations imbedded within any of the quantities or costs that comprise the individual WBS cost elements that roll-up to the figures shown in the table.

System (Phases I, II & III)	**Estimate ($ x million)**
Capture $665	
Storage $160	
Sub-Total	**$825**

Table 12 – Overnight Costs Capture & Storage Systems

5.3 Application of Escalation

As previously noted a composite escalation forecast was developed based on inputs by the entities (internal and external source inputs) for a number of categories and sub-categories shown in Table 13. For each of the categories or sub-categories, composite factors were developed for each of the future project years.

Category	Sub-Category
Civil Work	Concrete
	Buildings
	Labor
Mechanical Work	Structural Steel
	Fabricated Equipment
	Machinery & Equipment
	Tanks
	Piping
	Labor
Electrical Work	Equipment
	Cable
	Commodities
	Instrumentation & Controls
	Labor
Purchased Services	
Professional Services	
Travel & Entertainment	

Table 13 – Escalation Categories

The composite escalation factors for future years are not shown in the table due to proprietary reasons. Overall escalation was calculated to be $71-million dollars, averaging about 9%/yr.

5.4 Application of Risk Based Contingency

Separate meetings were held among the entities to determine which WBS line items had risk and/or opportunity potential and to what extent. A risk analysis was performed using the double triangle method advocated by the Association for the Advancement of Cost Engineering, International in their recommended practice 41R-08, Risk Analysis and Contingency Determination Using Range Estimating. The practical application of the method involved the identification of risks or opportunities that had the potential to exceed one-half percent of the cost estimate, at the lowest WBS level. WBS elements that did not contain a one-half percent risk were held to a fixed number (meaning +/- 0%) The risks and opportunities identified and modeled for analysis using range estimating and a Monte Carlo technique included:

- <u>Number of and Cost of Intermediate Wells</u> – While the project team believes that an appropriate CO_2 monitoring well system has tentatively been designed for inclusion in a UIC permit application, a UIC permit has yet to be approved in the

U.S. for such a system. Interpretations of the number of intermediate monitoring wells, including the possible need to re-drill a failed well, could lead to a substantial cost increase. The impact of the risk will only be known at the time of issuance for a UIC permit.

- 3D Seismic Survey and Analysis – Similar to the discussion above regarding first issuance of UIC permit in the U.S., the extent of required 3D seismic survey may be uncertain. Additionally landowner access is required to perform the activity and potential delays associated with securing the access adds to cost uncertainty.
- Number of Injection Wells – The drilling of characterization wells and associated geologic analysis and reservoir testing increases the likelihood that an injection well will perform as intended. However, from a risk management standpoint, certainty of injection well performance is not fully known until a well is put into service for a period of time. The likelihood of having to develop a backup injection well site cannot be dismissed. Also, given the nature of well drilling, considerable work could be performed drilling to a mile deep or more and the well may have to be abandoned and plugged due to a number of possible reasons.
- Cost of Deep Wells – As noted above, given the nature of well drilling, considerable work could be performed drilling to a mile deep or more and the well may have to be abandoned and plugged due to a number of possible reasons; productivity of drilling could also be impacted due to unanticipated impacts. Risk of having to drill an additional well and/or slowed productivity cannot be dismissed.
- Volatility of Escalation – Overall project escalation, calculated at $71-million dollars, has considerable range in the directions of opportunity or additional risk. AEP applied its proprietary view to future project escalation, considering probabilities associated with scenarios that could include a future recession to hyper-inflation. AEP considered escalation volatility associated with labor, materials and purchased services.
- Labor Overtime – The project construction schedule was built using a 5-8s work week (working five days a week - eight hours a day). Concern exists over a recent flurry of regulations that would put considerable demand on limited available qualified craft labor. The construction schedule may need to be adjusted to as much as 6-10s work weeks to attract sufficient qualified labor resources. To a lesser extent, potential permit delays could compress the construction schedule.
- Structural Steel – Structural steel was modeled as an opportunity. The red team reviews among the entities identified likely areas within the design that will likely offer savings when further reviewed in Phase II.

Shown in Figure 22 is a relative ranking of the cost impacts associated with the risks and opportunities modeled for the project. As illustrated in the figure, the largest risks to the project lie in uncertainty associated with development and installation of the CO_2 storage system, followed by escalation volatility, and potential labor overtime. Lines shown for support steel are reflective of opportunities.

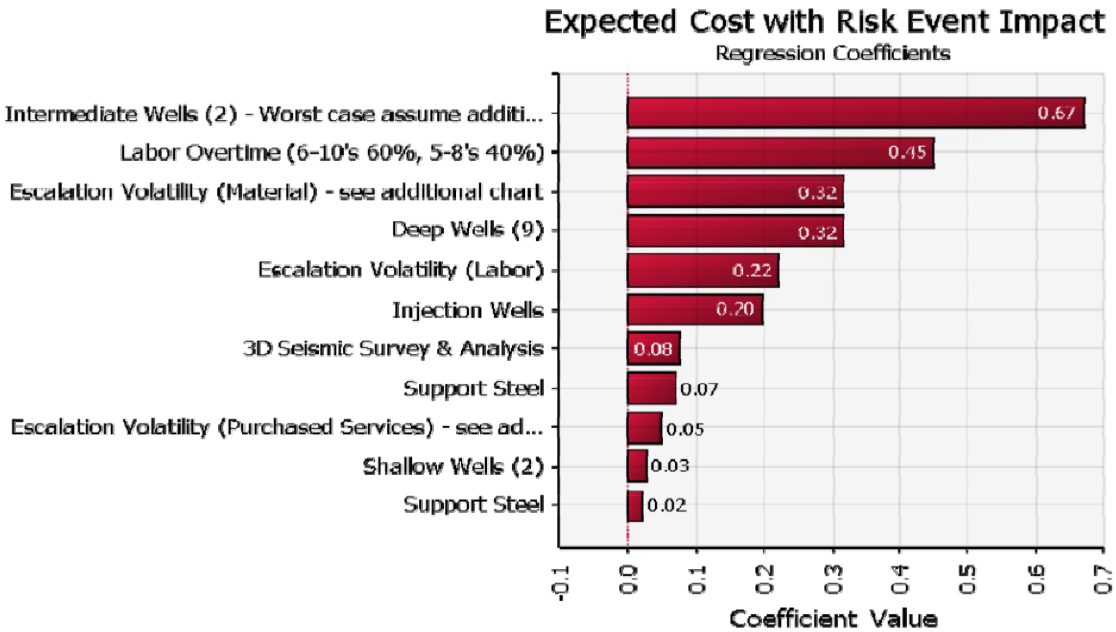


Figure 22 – Relative Ranking of Risks and Opportunities

A number of other risks and opportunities were also considered but not modeled in the analysis, as AEP felt that the probabilities and/or certainties of occurrence and impacts associated with the risks and opportunities would balance each other. Included among a number of other risks and opportunities considered, were:

- Technology Scale-up Risk – Includes unknown but expected issues that normally arise in scaling up a technology and/or process.
- Design Optimization Opportunity – The schedule for the FEED supported development the targeted deadline for compiling and completing the cost estimate did not include time for detailed engineering or time to refine or optimize the integration of various carbon capture system components. The project team feels confident that cost savings will be identified in Phase II detailed engineering.
- Installed Spares – Alstom completed their RAM study following the compilation of the cost estimate. The project team is confident that a number of installed spares can be eliminated from the design. Final decisions and the extent of installed spares that can be taken out of the design will be addressed in Phase II.
- Modularization – AEP has considerable experience with modularization of retrofit project components; a select number of opportunities will be addressed in Phase II.

AEP's risk based evaluation of the cost estimate determined a need to add up to $103-million dollars to the project estimate to insure that adequate funding is reserved, to fully fund Project Phases II - IV. The risk based contingency will be revisited as additional risks and opportunities are identified and/or near the end of Phase II when an updated +/- 10% cost estimate is due.

5.5 Total Project Cost Range

The overall total project cost includes an estimated $66-million dollars associated with Phase IV operations of the capture and storage systems over a planned four year DOE project operating life, starting September 1, 2015 and ending June 28, 2019. Shown in Table 14 is an expanded project cost estimate that includes previously discussed escalation, risk based contingency and Phase IV Operations. The $1.065-billion dollar figure represents an approximate 99.5% level of confidence that the project will under run that amount.

System (Phases I, II & III)	Estimate ($ x million)
Capture System	$665
Storage System	$160
Sub-Total (Overnight Cost)	**$825**
Escalation	$71
Sub-Total (As Spent)	**$896**
Risk Based Contingency	$103
Total Constructed Cost	**$999**
Phase IV Operations	$66
Total DOE Project Cost	**$1,065**

Table 14 – Upper Limit Project Cost, Including Four Years of Operations

Shown in Figure 23 is an output of the risk model applied to the project cost estimate showing that the project is likely to have an estimate at completion (Phases I – IV) within the range of $962-million and $1.065-billion dollars. The y-axis of Figure 23 represents the confidence level (e.g. 0.8 = 80%) that the project will not exceed the value of the curve correlating to the dollar figure in the x-axis.

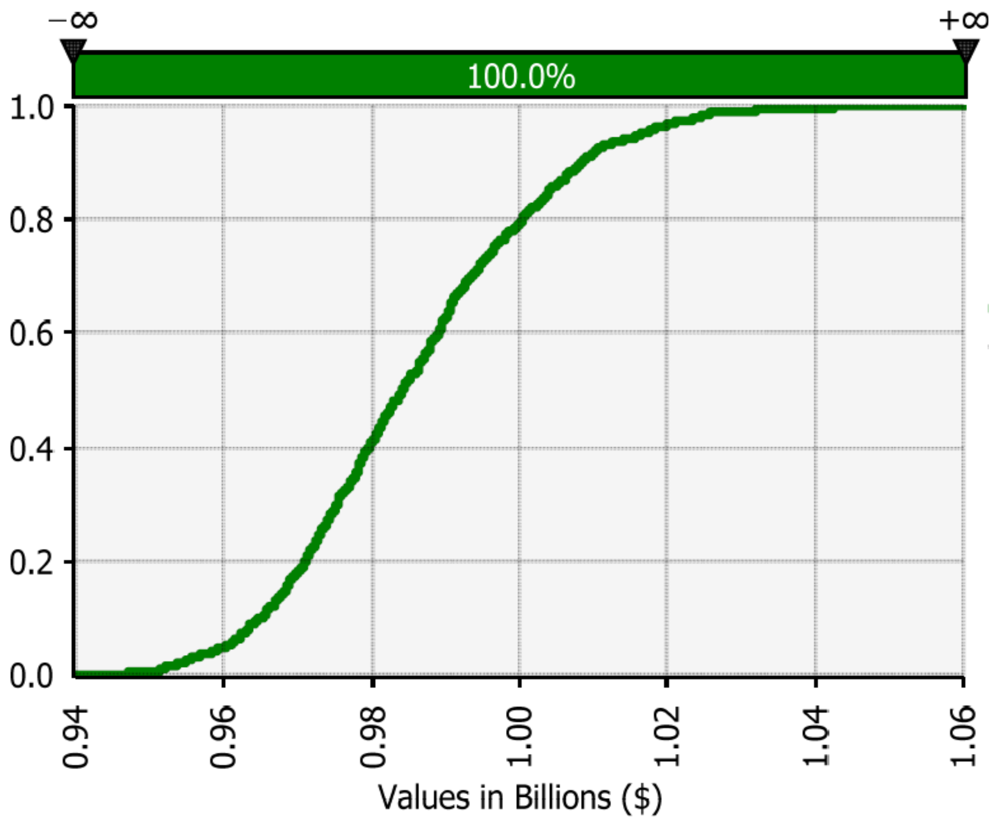


Figure 23 – Probability of Total Project Cost Under Run

The estimated range of total installed project cost (excluding Phase IV operations) is between $3,500/kW and $3,900/kW. The reader is reminded that the MT CCS II Project is a "First-Of-A-Kind" or "Serial Number One" commercial demonstration facility, intended to operate at a 260 MWe (gross) or 235 MWe (net) scale-up. The estimated cost of n^{th} of a kind version of this facility is expected to be less.

6.0 CCS Commercialization

At the Phase I decision point, AEP communicated to the DOE its plans to dissolve the existing cooperative agreement and postpone project activities following the completion of Phase I. At the time of the communication, AEP noted that when the original grant application was submitted by AEP in response to DE-FOA-0000042, AEP believed it important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations concerning CO_2 emissions at its coal-fired power plants. Various bills in Congress were introduced to limit emissions but also provide funding for early CCS projects. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP's cost share of the Mountaineer Commercial Scale Project.

Notwithstanding AEP's decision to dissolve the existing cooperative agreement and postpone project activities, AEP and its extended project team successfully completed the Phase I effort for the Mountaineer Commercial Scale Carbon Capture and Storage Project, as outlined in the cooperative agreement. Within Phase I the cooperative agreement called for:

- The resolution of outstanding conditions with the U.S. Department of Energy (DOE) cooperative agreement;
- Project specific developmental activities (i.e., front-end engineering and design);
- The initiation of the NEPA process; and
- The identification of exceptionally long lead time items.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction and operations related) from the PVF and the design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

Based on the work completed in the front-end engineering and design package, AEP and its extended project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Issued preliminary PFD and overall mass and energy balances, and
- Completed preliminary project design.

The work completed in Phase I continues to support AEP's belief that the Alstom CAP technology is ready for commercial demonstration at the intended scale. The work completed also provides AEP and DOE with a good understanding of the project's risks, capital cost, and expected operations and maintenance costs during planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere in the U.S.

7.0 List of Abbreviations and Acronyms

AEP	American Electric Power, Inc.
ASME	American Society of Mechanical Engineers
ASTM	American Society of Testing Engineers
AQCS	Air Quality Control Systems
BA-02	Name of Characterization Well drilled at Borrow Area Site
BFPT	Boiler Feed Pump Turbine
BOP	Balance of Plant
Btu	British thermal unit
CAP	Chilled Ammonia Process
CCPI	Clean Coal Power Initiative
CCS	CO_2 Capture and Storage
CEMS	Continuous Emissions Monitoring System
CO_2	Carbon Dioxide
COE	Cost of Electricity
CP	Cathodic Protection
CCVTs	Coupled voltage transformers
DCC	Direct Contact Cooling
DCS	Distributed Control System
DOE	United States Department of Energy
EAC	Estimate-At-Completion
ESP	Electrostatic Precipitator
FOAK	First-of-a-Kind
FRP	Fiberglass Reinforced Plastic
GEP	Good Engineering Practice
GS	Geologic Sequestration
HP	High Pressure Turbine
IP	Intermediate Pressure Turbine
kJ	1000 Joules
LP	Low Pressure Turbine
MT CCS II	Mountaineer Carbon Capture & Storage Project
MVA	Monitoring, Verification, and Accounting
MW	Mega Watt
MWe	Mega Watt Equivalent
NACE	National Association Corrosion Engineers
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
OEM	Original Equipment Manufacturer
OIT	Operator Interface Terminal
P&ID	Process & Instrumentation Diagram
PFD	Process Flow Diagram
PLC	Programmable Logic Controllers
PSI	Pounds per Square Inch
PVF	Process Validation Facility
RAM	Reliability, Assessability and Maintainability

SCR	Selective Catalytic Reduction
TDS	Total Dissolved Solids
TSS	Total Suspended Solids
UIC	Underground Injection Control
USDW	Underground Sources of Drinking Water
VFD	Variable Frequency Drive
WMMS	Well Maintenance & Monitoring System
WVDEP	West Virginia Department of Environmental Protection
WFGD	Wet Flue Gas Desulfurization

Appendix A - Final Report, Mountaineer CCS II Project: BA-02 Summary Characterization Report

Final Report

Mountaineer CCS II Project:
BA-02 Summary Characterization Report

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September 2011

Notice

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FIGURES

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1 INTRODUCTION AND BACKGROUND

This document reports on geologic investigation and the formation testing that were conducted in the BA-02 well at the American Electric Power's (AEP's) Mountaineer Power Plant near New Haven, West Virginia. The BA-02 well was drilled from December 2010 through March 2011 to provide geologic characterization data to support the design of a commercial-scale carbon dioxide (CO_2) capture and storage facility that would be capable of capturing and sequestering 1.5 million metric tons (MMT) of CO_2 per year. The installation and characterization of the BA-02 well were conducted as part of Phase I (Project Definition Phase) of the commercial-scale project (CSP), which is being conducted under the U.S. Department of Energy (DOE) Clean Coal Power Initiative (CCPI).

This report is focused on the preliminary integration between the geology and the reservoir testing and the further work required to create a whole geologic understanding of the area. Further information on the geology can be found in "Mountaineer CCS II Project: Phase I Geologic Characterization" (Battelle, 2011) and further information on the reservoir testing can be found in "Mountaineer CCS II Project: Hydrologic Well Testing Conducted in the BA-02 Well American Electric Power Company, Mountaineer Plant, New Haven, West Virginia" (Battelle, 2011).

In addition to the information collected during the current Project Definition Phase from BA-02 wells, the analysis and interpretation presented here relies heavily upon the work conducted under two other projects at the site. The first project included an initial site assessment work funded by DOE and other partners during 2002-2007. This phase included a seismic survey, drilling of the AEP-01 test well, and preliminary modeling and feasibility assessment for pilot-scale projects. Starting 2007, AEP contracted Battelle to conduct geologic storage assessment work under a CO_2 capture and storage project called the Project Validation Facility (PVF). This effort included drilling and completion of five injection or monitoring wells at the plant and injection and monitoring of CO_2 in lower Copper Ridge Dolomite and the Rose Run Sandstone. An objective of drilling the BA-02 well, located about 3 miles from the Plant, was to evaluate the geologic and reservoir continuity in the broader area around the Plant so that the storage feasibility for CCPI project could be determined.

Additional activities during Phase I included regional geologic framework assessment, reservoir modeling to evaluate design scenarios, development of preliminary well configurations and monitoring plans, and development of cost estimates for the entire project. Given the compressed schedule of Phase I and the fact that the data from BA-02 well only became available near to the end of this phase, the design and cost efforts were largely based on the conceptual model developed from the PVF project data. The intent of the subsequent detailed design under Phase II was to integrate all existing and new data from the facility to develop more robust reservoir models and to validate or update Phase I conceptual design assumptions.

1.1 BACKGROUND

1.1.1 Characterization Activities at the AEP BA-02 Well

An 8,875-foot deep well (BA-02) was completed two miles south of the Mountaineer Power Plant site to characterize CO_2 storage opportunities. The borehole penetrated all of the Copper Ridge formation and was drilled into the Maryville dolomite. Well construction methods were designed to facilitate the reservoir testing in the open borehole section with specific emphasis on the Beekmantown dolomite, Rose Run sandstone, and Copper Ridge dolomite Formations. Figure 1-1 is the as-built diagram of the well. A full suite of wireline logs was completed to obtain a continuous log of the rock formations in the test well. Wireline logs were used for identifying formations, casing points, reservoir potential, and selection of coring points. Over 40 rock formations were identified through evaluation of wireline logs, drill cuttings logs, and rock cores. Most of the rock consisted of dense shale, mudstone, limestone, dolomite, and sandstone. In broad terms, the geologic sequence encountered in BA-02 was consistent with the pre-drilling prognosis that was developed from PVF area wells. However, as discussed later there are some differences in the reservoir properties, which is not unexpected for exploratory stage projects.

A continuous oriented core in the Black River unit was taken for 30 feet and measured 4 inches in diameter; continuous core in the Copper Ridge Formation was taken for ~270 feet and measured 3.5 inches in diameter. In all, 67 sidewall cores were collected from key depth intervals. The rock core samples were subject to many hydraulic, geochemical, and geomechanical tests to determine the suitability of key formations for CO_2 injection and storage.

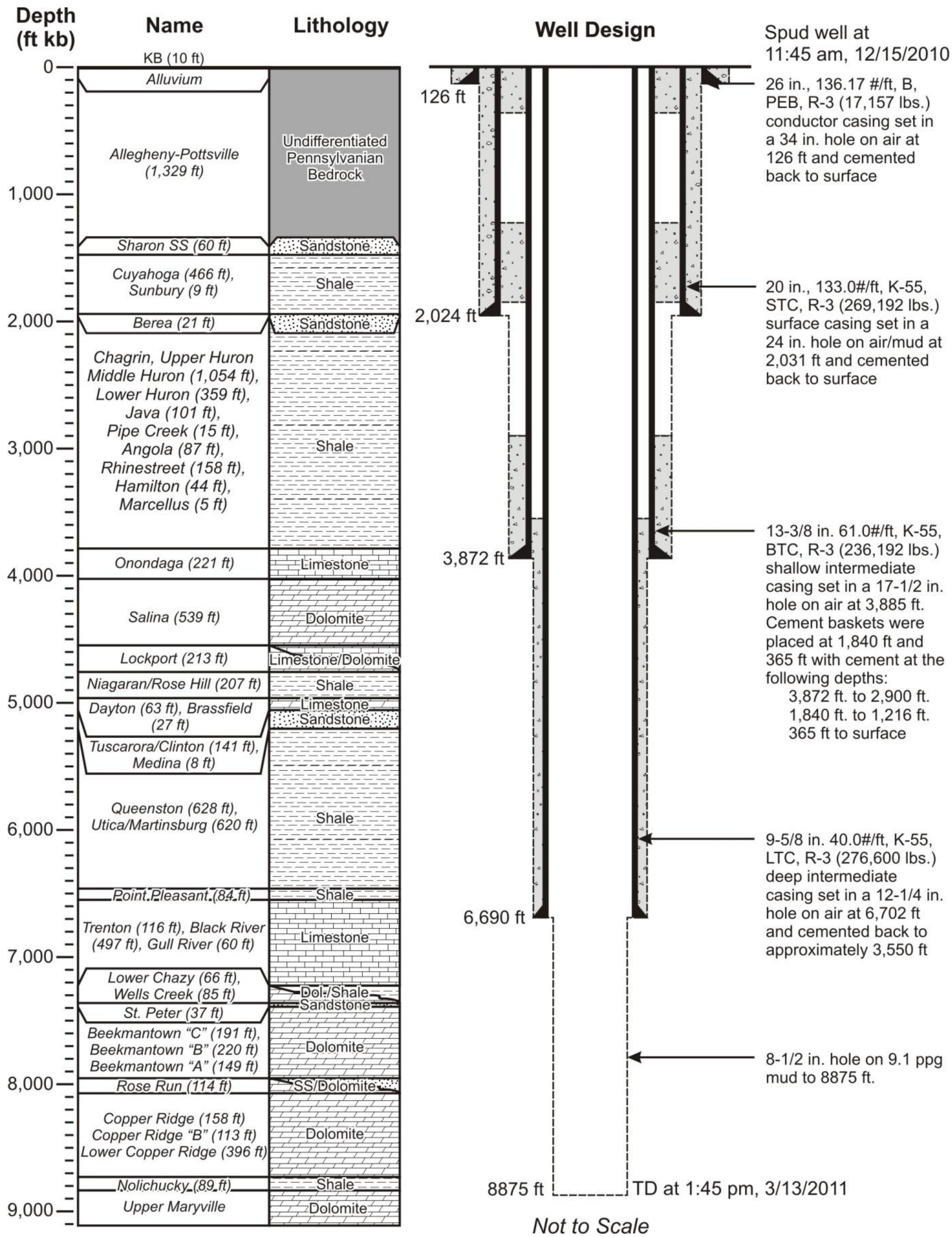

Figure 1–1. As-built diagram and geologic column for BA-02 well

1.1.2 Hydrologic Testing Performed at the AEP BA-02

The hydrologic testing program included two phases of well tests during April-May, 2011. Phase I involved conducting an initial flowmeter logging survey of the entire open borehole section to identify fluid inflow zones (zones that are capable of taking fluid) as these zones may be candidate zones for CO_2 injection. Phase II involved conducting a series of detailed hydrologic tests on selected zones that were identified as candidate injection CO_2 zones based on the results of the Phase I testing and other geologic characterization data including geophysical logs and core data. Table 1-1 summarizes the testing performed in the BA-02 well. A more complete summary of the objectives and test methods is provided in the "Data Analysis Plan for Phase 1 of the Commercial Scale Carbon Storage Project" (Battelle, 2010) and in "Mountaineer CCS II Project: Hydrologic Well Testing Conducted in the BA-02 Well American Electric Power Company, Mountaineer Plant, New Haven, West Virginia" (Battelle, 2011).

Table 1-1. General Summary of Hydrologic Tests Performed in BA-02 Well

Phase/Dates	Description
Phase I April 4-7, 2011	Flowmeter logging survey of the open borehole section from 6,690 to 8,875 ft. This phase of testing included a baseline fluid logging survey conducted under static (no injection) conditions and additional surveys conducted while injecting brine at rates of 2, 4, and 6 bpm.
Phase II May 1-26, 2011	Detailed hydrologic tests of selected candidate CO_2 injection horizons within the open borehole section from 6,690 to 8,875 ft. In all, three candidate test zones were successfully isolated and tested, including the Lower Copper Ridge Formation below a depth of 8,320 ft; a 158-ft section within the Rose Run Sandstone between depths of 7,918 and 8,076 ft; and a 158-ft section within the "B" Zone of the Beekmantown Formation, between depths of 7,670 ft and 7,828 ft. An expanded 275-ft section of the Beekmantown Formation that included the Beekmantown B Zone and a portion of the overlying Beekmantown C Zone (7,550 to 7,825 ft) were also conducted.

2 GEOLOGIC INFLUENCE ON RESERVOIR TESTING

The basic geologic interpretation was used as the initial input into the reservoir testing design. Ideally, the entire geologic interpretation, including both wireline log and core analysis data, would have been used as an input into reservoir testing design. However, due to time constraints, the preliminary analysis focusing on the triple combo log was used as a first cut. The flowmeter survey was then used to refine the testing zones. The following summarizes the process used to select the final zones.

2.1 WIRELINE ANALYSIS

Thresholds that were considered minimum reservoir values were determined for each of the cited log types consistent with the analysis of logs from PVF project wells. Because of the averaged vs. point-specific nature of log data, and because of the potential for spatial variability in reservoir character, the assignment of threshold values is based on a sum of interpretation experiences and is subjective in nature.

The values provided in the Log ASCII Standard (LAS) digital data were filtered to identify sections in the wellbore that exceeded the assigned threshold values. The results of this filtering were appended to the gamma ray-neutron-density-photoelectric log values from the AEP BA-02 well. The final ranking of potential reservoirs was based on the multiplicity of positive indicators across any given zone in the well.

Density and neutron porosity cutoffs were set at 6%. This value is generally considered a practical minimum for oil and gas reservoirs. Below about 6% porosity, permeability and bound water become critical constraints for reservoir performance.

Captured resistivity values were set up to 75 ohms. In practice, most of the values that fell under the 75-ohm limit would also come through a 30-ohm filter.

A method was required by which the entire wellbore could be broken down to parts and assigned a value for prioritizing the reservoir testing intervals. Each zone with filtered values was assigned a probable reservoir value, this being a simple scale of 1 to 3, where

1. a primary or certain reservoir, one thought to be integral to the sequestration project
2. a contributing reservoir, one whose utility to the project would be reduced somewhat for reasons of volume or rate
3. possible but unlikely reservoir, something nonetheless to be aware of.

Ten potential test sections were assigned initially.

Some examples of test section makeup might be:

- A single zone with particularly impressive character with regard to potential injectivity

- A succession of adjacent zones with similar character

- A succession of adjacent zones of mixed character, but one of which is clearly superior and will likely stand out from the others in testing

Using this approach, a list was constructed from the individual zones of interest that were identified by the filtering process. Figure 2-1 provides a breakdown of the zones of interest in graphic format, indicating interval, formation name, log values, interpreted reservoir value, and assigned test stage.

2.2 FLOWMETER ANALYSIS

Figure 2-2 illustrates the results of the dynamic flowmeter logging surveys conducted at constant injection rates of 2, 4 and 6 bpm. Figure 2-1 shows the downward flow as a function of depth for each injection rate. The downward flow rate at the bottom of the intermediate casing (approximate depth of 6,690 ft) represents 100% of the injection rate entering the open borehole section. The amount of downward flow decreases where an inflow zone is present that takes some of the injected fluid. These zones are indicated by a shift to the left in the flow curve. Figure 2-2 shows actual flow curves and a smoothed version of the actual flow curve, which has been manually drawn to facilitate interpretation of the flow curves. For all three injection rates, the most significant inflow zone occurs within the lower part of the Copper Ridge Formation between approximate depths of 8,300 and 8,500 ft. There is no downward flow past this zone, indicating that there are no other inflow zones below this depth or the injectivity of this zone exceeds the downward flow rate reaching this zone. Other apparent in-flow zones occur within the Rose Run Sandstone, the lower part of the Beekmantown B Zone, and the St. Peter Formation. In general, the results of the three dynamic flowmeter logging surveys are similar.

AEP #BA-02 Zones of Interest and Test Stages

INTERVAL	FORMATION	DENSITY Por > 6.0	NEUTRON Por > 6.1	RESISTIVITY < 75 Ohms	Mag Res PERM mD	PROBABLE RESERVOIR VALUE	10-Stage Plan	
7396-7406	Beekmantown C	-	14.4	15	10.0	1	1	Single, unlikely section
7418-7423	Beekmantown C	-	10.8	-	-	3		
7575-7576	Beekmantown C	-	9.1	-	-	3		
7577-7581	Beekmantown C	-	10.9	16	-	3		Widely scattered,
7585-7586	Beekmantown C	7.2	10.0	61	-	3	2	possible/unlikely
7590-7591	Beekmantown B	7.5	-	69	-	3		sections
7594-7596	Beekmantown B	7.1	-	39	-	3		
7600-7604	Beekmantown B	15.8	13.1	4	3.5	1		Thin, with primary and
7614-7624	Beekmantown B	-	11.5	37	3.1	2	3	contributing sections
7682-7684	Beekmantown B	11.8	-	70	-	3		
7706-7710	Beekmantown B	-	10.4	22	0.8	3		
7712-7719	Beekmantown B	9.0	11.9	14	6.0	1		Mixed potentials, but
7723-7731	Beekmantown B	7.9	-	18	0.7	2	4	contains two primary
7732-7735	Beekmantown B	7.2	9.1	12	-	2		sections
7739-7748	Beekmantown B	8.3	10.9	10	6.0	1		
7751-7756	Beekmantown B	6.2	10.1	12	-	2		
7768-7773	Beekmantown B	6.3	9.5	15	1.8	2		
7778-7786	Beekmantown B	9.5	12.7	5	6.0	3		
7786-7788	Beekmantown B	-	9.7	16	1.0	3	5	Mixed potentials, but
7792-7798	Beekmantown B	17.3	17.9	10	5.0	1		contains two primary
7799-7802	Beekmantown B	6.5	9.8	17	1.2	2		sections
7857-7862	Beekmantown A	16.0	14.1	7	4.0	1		
7936-7942	Beekmantown A	7.1	-	12	-	3		
7954-7958	Rose Run	10.9	-	13	-	3		
7961-7966	Rose Run	7.7	-	8	7.0	2		
7970-7973	Rose Run	7.3	-	32	6.5	3		Multiple thin, unlikely
7985-7989	Rose Run	11.5	-	58	0.5	3	6	reservoir sections
7994-7996	Rose Run	9.0	-	33	-	3		
7999-8000	Rose Run	9.2	-	39	-	3		
8004-8005	Rose Run	9.1	-	65	-	3		
8016-8027	Rose Run	14.1	9.7	5	33.0	1	7	Single, primary or
8066-8068	U Copper Ridge	8.7	-	-	-	3		certain section
8085-8092	U Copper Ridge	10.3	-	-	-	3		
8118-8123	U Copper Ridge	-	10.3	-	-	3	8	Widely scattered,
8186-8188	U Copper Ridge	-	9.7	-	0.8	3		unlikely sections
8351-8355	L Copper Ridge	-	11.4	-	-	3		Single contributing
8359-8368	L Copper Ridge	19.7	18.0	61	0.6	2	9	section
8375-8378	L Copper Ridge	-	10.0	-	-	3		
8384-8386	L Copper Ridge	-	10.2	54	-	3		
8391-8394	L Copper Ridge	-	11.1	-	1.2	3		
8406-8408	L Copper Ridge	-	9.8	40	-	3		
8412-8414	L Copper Ridge	-	11.4	-	-	3		
8425-8428	L Copper Ridge	-	11.9	47	-	3		Widely scattered,
8432-8434	L Copper Ridge	-	10.5	-	-	3	10	possible/unlikely
8443-8444	L Copper Ridge	-	9.4	-	-	3		sections
8469-8475	L Copper Ridge	6.4	12.5	-	-	3		
8478-8487	L Copper Ridge	-	11.7	55	1.2	3		
8489-8491	L Copper Ridge	-	10.9	-	-	3		
8629-8633	L Copper Ridge	12.9	-	28	2.5	2		
8683-8687	L Copper Ridge	7.2	-	-	0.8	2		

* 1 Primary or certain reservoir

* 2 Contributing reservoir

* 3 Possible but unlikely reservoir

BorrowTestStagesV3.xls

Figure 2–1. Characteristics of zones for reservoir potential and assigned test stage

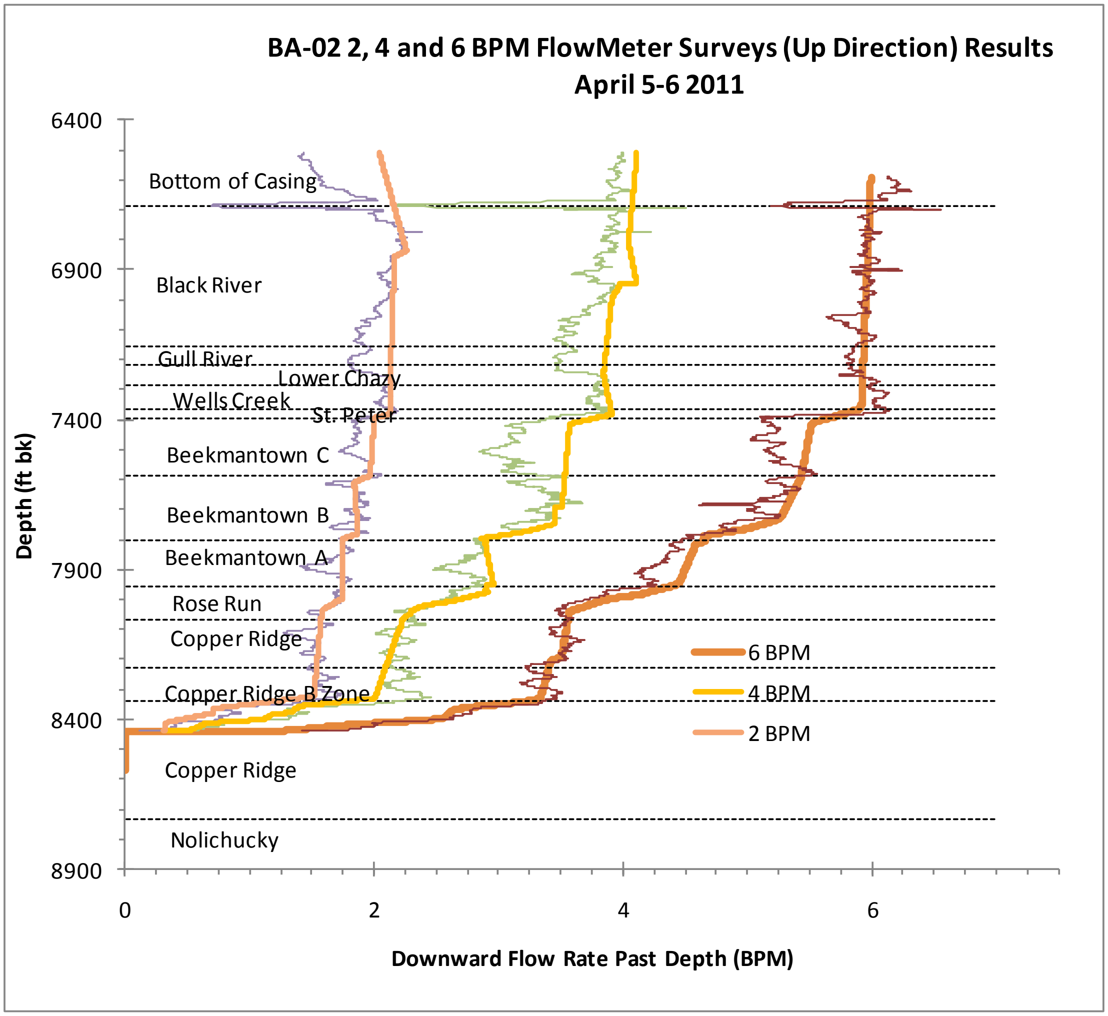

Figure 2-2. Composite Figure Showing Results of Flowmeter Data for 2, 4 and 6 bpm Dynamic Surveys

2.3 FINAL TESTING ZONE SELECTION

The final testing zone selection was primarily based upon the flowmeter data. However, as can be seen on Table 2-1, many of the zones line up very closely. Test Zone 4 is roughly equivalent to Zones 4 and 5. Test Zone 3 roughly encompasses the Rose Run, as do Zones 6 and 7. Test Zones 1 and 2 correspond to Zones 9 and 10. Some of the discrepancy has to do with packer placement.

Table 2-1. Comparison between the Geologic Test Zones and the Reservoir Test Zones

Formation	Depth (ft)	Geologic Test Zone (ft)	Reservoir Test Zone (ft)
Beekmantown C	7400	Zone 2 (7418-7596)	
	7500		
Beekmantown B	7600	Zone 3 (7600-7624)	Test Zone 5 (7550-7838)
	7700	Zone 4 (7682-7756)	Test Zone 4 (7660-7838)
Beekmantown A	7800	Zone 5 (7768-7862)	
Rose Run	7900	Zone 6 (7936-8006)	Test Zone 3 (7918-8076)
	8000	Zone 7 (8016-8027)	
Copper Ridge	8100	Zone 8 (8068-8188)	
Copper Ridge "B" Zone	8200		
Lower Copper Ridge	8300	Zone 9 (8351-8368)	Test Zone 2 (8320-8510)
	8400	Zone 10 (8375-8687)	
	8500		Test Zone 1 (8510 - TD)
	8600		

3 OVERALL RESULTS

Overall, the geologic interpretation and the reservoir testing yielded complimentary results. For example, the interval contained the vugs in the core corresponds to Test Zone 2, the best interval in the well. Figure 3-1 illustrates the location of the test zone and the vugs.

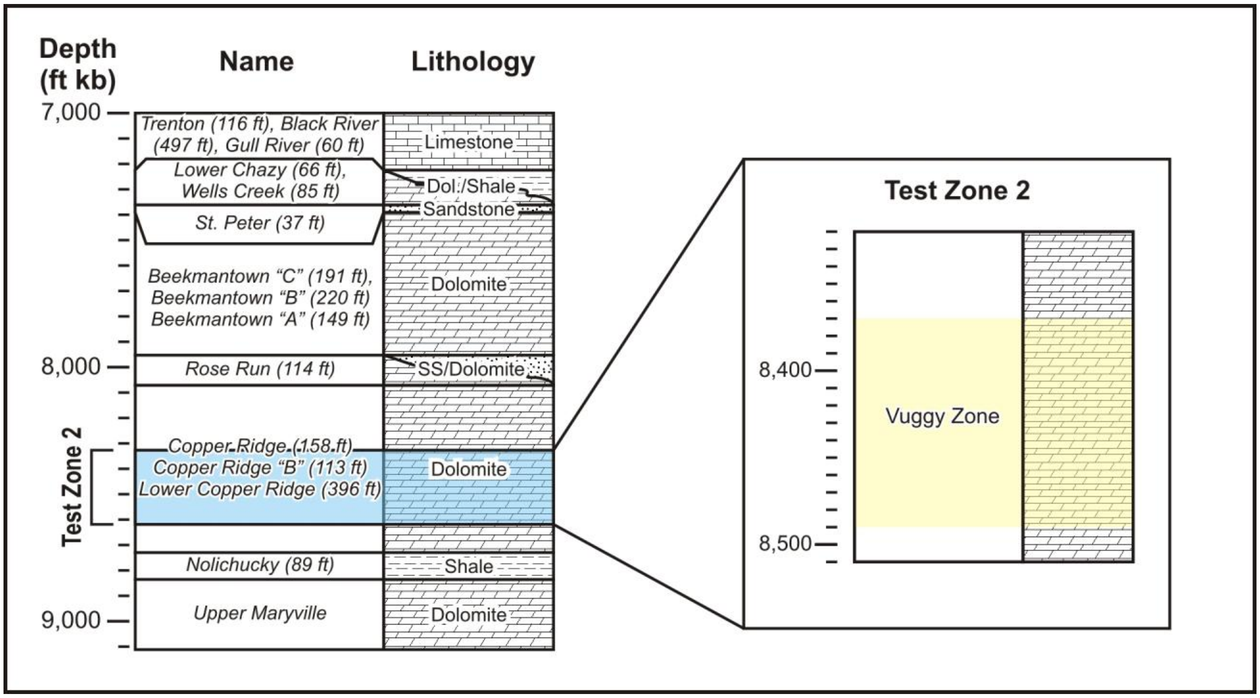

Figure 3-1. Comparison between Test Zone 2 and the vuggy interval

3.1 SUMMARY OF GEOLOGIC ANALYSIS RESULTS

Wireline logs run in the AEP BA-02 well exhibited an array of potential reservoirs, but with highly varying injection potential. Data acquired from the previous PVF well tests indicated that the reservoir is essentially contained in a single zone in the upper portion of the lower Copper Ridge Formation with significantly lower injectivity in the Rose Run Sandstone. The thinner zones of porosity observed in the Beekmantown zones in the PVF wells were not tested. Data acquired from the Borrow Area well indicate that the lower Copper Ridge Dolomite still provides the largest potential reservoir in the area. However, reservoir potential in the Beekmantown and Rose Run Formations in the BA-02 well also indicate improved reservoir character compared to PVF wells. As an overall trend, the average porosity for all potential reservoir zones tracked the closest to the porosities derived from log cross plots. Neutron porosity tended to track high across all zones, while density porosity tended to track lower. The best zones of calculated porosity, Zones 7 (Lower Rose Run) and 9 (Upper Lower Copper Ridge), correlated well with the best indications of porosity from the crossplots.

Image log analysis of the reservoir sections did not indicate large numbers of natural fractures. It does show a fair amount of drilling induced fractures, particularly in the Queenston and Utica shale sections; however this is not uncommon or unexpected. In any 10-foot section, it is rare to find more than five fractures, including drilling fractures. In this log image, the maximum count is 12 fractures in a 10-foot interval within the Queenston shale section. The Beekmantown Formation is not an overly fractured system. Overall, the dominant type of fracture is drilling-induced. Zone 3 (Beekmantown B Zone) has the highest concentration of natural fractures. This may indicate that the porosity in this interval is fracture-controlled. The Rose Run Formation has a low density of fractures compared to most of the rest of the well. It does not appear that the porosity in the Rose Run is due to secondary porosity. Although it appeared that the vugs developed along fractures in the Copper Ridge Formation, this phenomenon is not well represented in the image logs. It is likely the fractures seen in the cores were not easily interpreted within the log. There are no drilling induced fractures in the interval where vugs are present; however, there are some natural fractures, which are likely a subset of the ones represented in the core.

The AEP BA-02 well core CT scan was utilized to determine with greater precision the presence and depths of vugs within the Copper Ridge dolomite. The correlation between internal structure and observation on the whole and slabbed core was confirmed. The connectivity of the vugs throughout the core was also established by being able to see into the core with the CT scan technology. The CT scan also revealed the tendency of the vugs to track along fracture features. Finally, the highly variable nature of the vugs with respect to vertical depth was confirmed.

In the AEP BA-02 well, there is a good correlation between core identified vugs to the triple combo neutron peaks to vugs visible on the image log. A neutron cut off at 7–8% captures nearly all of the vuggy intervals that were identified in the core. Applying this same process to AEP-1 yielded similar results with neutron peaks correlating well with areas of “vuggyness” in the image log. Within the Lower Copper Ridge, an upper and lower bound to the vuggy interval was identified. This interval was approximately 130–140 feet in total thickness, which correlates well with the current depositional model. The vugs are not present everywhere throughout this larger interval. The upper and lower bounds can be distinguished by a background neutron level shift as well as correlating minor deflections in the triple combo logs. This work essentially allows the identification of the vuggy intervals by the triple combo only. Since it is positively correlated in the core in BA-02, future wells may have less need to take full core in the same intervals. Further, by tying the vuggy intervals to the triple combo, future work may be able to tie it to the 3D seismic as the gross interval of 130–140 feet should be resolvable on 3D seismic. The individual 6-foot zones will not be resolvable, but the larger zone where the vugs are present could be mapped. This could potentially yield a prospecting tool for vugs via seismic surveys, which could reduce or eliminate the need for drilling more characterization wells.

3.2 Summary of Reservoir Testing Results

The testing program successfully identified candidate injection zones within the 2,185 ft open borehole section of BA-02 and provided quantitative estimates of key hydrologic properties for the candidate injection zones. The principal hydrologic parameters quantified during testing include transmissivity, permeability-thickness product, and storativity. Four zones account for essentially all of the transmissivity observed in the open borehole section of BA-02. These zones include: a 190 ft section the lower portion of the Copper Ridge Formation between depths of 8,320 and 8,510 ft; a 158 ft section of the Rose Run Formation between depths of 7,918 to 8,076 ft (this interval includes all 114 ft of the Rose Run Formation, plus 37 ft of the overlying

Beekmantown A Zone and 7 ft of the underlying Copper Ridge Formation); a 178 ft section of the Beekmantown B Formation between depths of 7,660 and 7,838 ft (this interval includes 32 ft of the underlying Beekmantown A Zone); and, a 110 ft section of Beekmantown C and Beekmantown B between depths of 7,550 and 7,660 ft. The latter two zones are contiguous zones and therefore may be better described as a single candidate injection zone.

Transmissivity of the four zones is as follows (from highest to lowest): 37.6 ft^2/d (permeability-thickness product of 13,926 mD-ft) for the Lower Copper Ridge; 2.9 ft^2/d (permeability-thickness product of 1,071 mD-ft) for the Beekmantown B/A Formation; 0.81 ft^2/d (permeability-thickness product of 300 mD-ft) for the Rose Run Formation and 0.71 ft^2/d (permeability-thickness product of 263 mD-ft) for the upper Beekmantown B/lower Beekmantown C. The 365 ft section of Lower Copper Ridge below a depth of 8,510 ft was determined to have negligible transmissivity of 0.058 ft^2/d (permeability-thickness product of 21 mD-ft). Storativity values for the four test zones fall within a range from 1.57×10^{-5} to 8.32×10^{-3}.

In summary, within the 2,185 ft section of open borehole that was evaluated, the Lower Copper Ridge Formation between 8,320 ft and 8,510 ft appears to be a zone having significant injection potential. The actual thickness of the transmissive zone within the 190-ft tested interval is not known but may be small, perhaps on the order of 30 ft, based on well logs from the BA-02 well and information obtained from the AEP-1 well at the nearby PVF site. Other zones of secondary importance include the Beekmantown B Zone (including the lowermost 37 ft of the overlying Beekmantown C Zone) and the Rose Run Formation, although the injectivity potential of these zones is significantly less than that of the Lower Copper Ridge. The geologic formations overlying the Beekmantown B (i.e., above 7,550 ft) are best characterized as non-reservoir material, as testing shows that this section has negligible transmissivity. The same can be said of the Lower Copper Ridge below a depth of 8,510 ft.

3.3 MODELING

A reservoir modeling analysis is needed to design an injection system capable of sequestering 1.5 MMT of CO_2 per year for five years at the AEP Mountaineer Power Plant Site. The hydrologic testing program conducted in the BA-02 well provides critical data (i.e., identification of candidate injection zones and quantification of key hydrologic properties) needed to develop an accurate reservoir model. Such a modeling analysis with BA-02 will be a logical next step in evaluating injection potential and design configurations., It is nevertheless possible to draw general conclusions about the suitability of the geology in the vicinity of the BA-02 well to support the commercial scale CO_2 storage facility.

A modeling analysis conducted based on PVF system data to support a preliminary design of the CSP storage facility (Battelle, 2011) demonstrated that two injection wells completed in the Lower Copper Ridge zones are likely to be sufficient meeting the project objective of sequestering 7.5 MMT (1.5 MMT/yr x 5 yrs) of CO_2. In the modeling analysis, the Copper Ridge injection zone was assumed to include an upper 30-ft thick zone with a permeability of 1,000 mD (permeability-thickness product of 30,000 mD-ft) and a lower 25-ft thick zone with a permeability of 50 mD (permeability-thickness product of 1,250 mD-ft), or a total permeability-thickness of 31,250 mD-ft. Both zones were assumed to have a porosity of 7 %.

The modeling analysis showed that when two injection wells are used to inject 1.5 MMT/yr of CO_2, for 5 years, each injecting one half of the target injection rate, an area of approximately 14 square miles around each injection well is required to accommodate CO_2. Reservoir properties used in the preliminary modeling analysis were derived from pressure transient analyses of reservoir pressure data from CO_2 injection events conducted in the AEP-1 and AEP-2 injection wells at AEP PVF, located at the Mountaineer Power Plant Site. Results of the hydrologic testing conducted in the BA-02 well suggest that the injectivity potential of the Copper Ridge Formation is high at this location but can vary by a factor of 2 or more over relatively small distances (i.e., a permeability-thickness product of ~14,000 mD-ft at BA-02 compared to a permeability-thickness product of ~30,000 at the PVF). This study also shows that other candidate injection zones are present within the 2,185 ft open borehole section that was tested, but their injectivity potential is relatively low compared to the Copper Ridge. Therefore, future modeling efforts should aim to determine how to best utilize the injectivity and storage capacity of these diverse zones in order to maximize injection potential while minimizing the land area needed to sequester the CO_2.

4 RECOMMENDATIONS

Both the final geologic data processing and the reservoir testing were completed late in the Phase I project. The detailed design effort under Phase II that would have included more comprehensive data analysis and integrated static and dynamic model development has been suspended at this time. As presented in this and companion reports for Phase I, a significant amount of new information has been collected. Consequently, there is additional analyses that can be completed on both as well as a formal integration of the results. This integration is highly recommended as it presents a unique opportunity for advancing geologic storage assessments in Appalachian Basin. It will allow for more specific information to be fed into the geologic models being developed to predict plume movement, help refine injection system design, and develop a more robust monitoring program. Additional analyses will also help reduce some of the project uncertainties and performance risks.

Examples of questions that arose from these analyses that may be answerable with further work include:

- How does the core derived permeability match with the reservoir test derived permeability? Does a transform exist between the two?

- What is the nature of the heterogeneity within the vuggy interval in the Lower Copper Ridge? How does the heterogeneous model used for reservoir test analysis match with the heterogeneity predicted by the depositional model?

- How do the sand lobes within the Rose Run behave over distance?

- How do alternative well designs such as horizontal wells, multiple zone completions, or open hole injection impact the CO_2 plume, pressure front, and number of required monitoring wells?

- What is the minimum suite of logging, coring, and testing required in future wells to reduce cost of overall program?

- Will a robust 3D seismic program help understand continuity and reservoir parameter variability within individual zones tested here and help optimize future well locations?

Additional research to address such topics at the site and broadly in the Appalachian Basin could be undertaken in the future.

Appendix B – Preliminary Monitoring Plan for the AEP Commercial Scale Project Appalachian Power Company Mountaineer Plant, New Haven, West Virginia

Battelle
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Preliminary Monitoring Plan for the AEP Commercial Scale Project Appalachian Power Company Mountaineer Plant New Haven, West Virginia

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June 22, 2011

CONTENTS

Figures

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Acronyms and Abbreviations

2D	two dimensional
3D	three dimensional
AEP	American Electric Power
APCO	Appalachian Power Company
bgs	below ground surface
^{14}C	Carbon-14
CBL	cement bond log
CCV	continuing calibration verification
CO_2	carbon dioxide
CRDS	cavity ring-down spectroscopy
c.u.	capture unit
ESG	Engineering Seismology Group
FB	field blank
FTIR	Fourier Transform Infra-Red
IC	ion chromatography
ICP-MS	inductively coupled plasma mass spectrometry
ICV	initial calibration verification
LCS/LCSD	laboratory control sample/laboratory control sample duplicate
MASIP	maximum allowable surface injection pressure
MB	method blank
MBHIP	maximum bottomhole injection pressure
MDL	method detection limit
MIT	mechanical integrity testing
MMT	million metric tons
MRCSP	Midwest Regional Carbon Sequestration Partnership
MS	mass spectrometry
MS/MSD	matrix spike/matrix spike duplicate
MT/D	metric tons per day
PLC	Programmable Logic Controller
PNC	pulsed neutron capture
PPS	Pioneer Petrotech Services, Inc.
psi	pounds per square inch
QC	quality control

RAT	radioactive tracer
RL	reporting limit
RPD	relative percent difference
RTU	remote terminal unit
SOI	silicon on insulator
TDS	total dissolved solids
UIC	underground injection control
USDW	underground source of drinking water
U.S. EPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
WMMS	well maintenance and monitoring system
WVDEP	West Virginia Department of Environmental Protection

1.0 Introduction

This document provides an overview of the testing and monitoring that will be deployed in conjunction with the Mountaineer II commercial-scale CO_2 capture and storage (CCS) project at the Appalachian Power Company's (APCO's) Mountaineer Power Plant near New Haven, West Virginia. The commercial-scale CO_2 capture and storage facility will produce and sequester up to 1.5 million metric tons (MMT) of CO_2 per year. The CO_2 will be separated, compressed, and piped to deep wells in the vicinity of the power plant where it will be injected into one or more subsurface rock formations.

The specific testing and monitoring requirements for the commercial-scale project are not known at this time because an Underground Injection Control (UIC) permit has not yet been issued for the project. Therefore, it was assumed that testing and monitoring requirements for the commercial-scale project will be similar to those for the ongoing pilot-scale CO_2 capture and storage project at the Mountaineer Power Plant. It was also assumed that the testing and monitoring requirements in the new Geologic Sequestration (GS) Rule will apply. The pilot-scale project is authorized by West Virginia Department of Environmental Protection (WVDEP) Underground Injection Control (UIC) Permit No. 1189-08-53, a Class V (experimental) permit. The Class V permit stipulates testing and monitoring requirements to verify that the experimental geologic sequestration project is operating as permitted and is not endangering underground sources of drinking water (USDW). The U.S. EPA, in December 2010, issued the GS Rule, which establishes a new class of injection well, Class VI, for wells that will be used to inject CO_2 into deep geologic formations for long-term storage (sequestration). The GS rule sets minimum federal technical criteria for Class VI wells for the purpose of protecting USDWs and mandates comprehensive monitoring of all aspects of well integrity, CO_2 injection and storage, and groundwater quality during the injection operation and the post-injection site care period. A Class VI UIC permit will be sought for the commercial-scale project; therefore, testing and monitoring requirements in the new GS Rule were considered in developing this testing and monitoring plan.

Another driver for monitoring requirements is the Mandatory Reporting of Greenhouse Gases Rule (MRR) (74 FR 56260), which requires that all facilities that inject CO_2 for the purpose of long-term geologic sequestration to report basic information on CO_2 injected underground and imposes additional monitoring to quantify CO_2 emissions to the atmosphere. Monitoring to comply with this Rule is discussed in Section 17 of the plan.

The Mountaineer CCS II project is currently in Phase I – site characterization and preliminary design, which extends through September 2011 (Table 1-1). The primary goal of Phase I is to develop a preliminary design and cost estimate for the CO_2 capture and sequestration facility. A testing and monitoring program for the GS facility is a major aspect of the overall storage program because testing and monitoring begins before the start of the active injection phase (Phase III) and continues through the post-injection and site closure phase. The scope of the

Moutaineer CCS II project includes four phases that extend through 5 years of active injection once the facility is constructed and operational (Table 1-1).

Table 1-1. Commercial-Scale Project Timeline

Phase	Purpose	Duration	Dates
I	Site Characterization and Preliminary Design	15 mos	June, 2010 thru Sept, 2011
II	Detailed Design	15 mos	Oct, 2011 thru Dec, 2012
III	Construction	32 mos	Jan, 2013 thru Aug, 2015
IV	Operation	5 yrs	Sept, 2015 thru Aug, 2020
a.	Post Injection	Tbd	Tbd

a. Post Injection Phase is not included in the scope of the Mountaineer CCS II Project.
Tbd: to be determined

2.0 Design Assumptions

This preliminary testing and monitoring plan was developed before site characterization and preliminary design is complete. Consequently, there are many critical unknowns associated with the design of the GS facility at this time, including the depth and number of CO_2 storage zones, the number, location, and design of CO_2 injection wells required to sequester 1.5 MMT/yr, and the anticipated size and distribution of the CO_2 and pressure footprint. All these factors must be known to develop a testing and monitoring program; consequently, assumptions were made regarding each of these criteria to support this preliminary testing and monitoring plan. These assumptions are described below.

2.1 Injection Zones

At this time, the proposed CO_2-storage zone is limited to the Copper Ridge Formation, which is one of the two formations that are currently being used to sequester CO_2 for the pilot-scale project. The Rose Run Formation is the other formation that is currently being used in the pilot-scale project; however, because of its low injectivity, this formation is not included in the current design for the commercial-scale project. Within the Copper Ridge Formation, there is a primary injection zone and a secondary injection zone. Table 2-1 summarizes key parameters for each injection zone based on knowledge from the pilot-scale project area. After Phase I site characterization activities are completed, this information will be revised.

Table 2-1. Assumed Key Injection Zones for the Commercial-Scale Project

	Copper Ridge Primary Zone	Copper Ridge Secondary Zone
Depth to Top (ft, bgs)	8321 (Borrow Area) 8571 (Jordan Tract)	8445 (Borrow Area) 8695 (Jordan Tract)
Net Thickness (ft)	30	25
Porosity (%)	7 to 10	7 to 10
Permeability (md)	~ 1,000	~ 50

*Preliminary information based on PVF injection testing (October and November 2010) and BA-02 logging and coring information as of March 17, 2011.

2.2 Number and Location of Injection Wells and Plume Size

A 2-D numerical reservoir model was developed to estimate the number of injection wells required to sequester 1.5 MMT/yr. Based on preliminary modeling results, it was determined that two injection sites will be adequate, each having a single injection well completed in the Copper Ridge Formation. Moreover, each Copper Ridge injection well would inject CO_2 into the Primary and Secondary Copper Ridge zones. The location of the injection sites is constrained by the availability of AEP-owned land in the vicinity of the Mountaineer power plant. Figure 2-1 shows the boundary of the power plant site and three other AEP-owned parcels in the vicinity of the power plant that were considered for hosting injection wells. The two sites selected to host

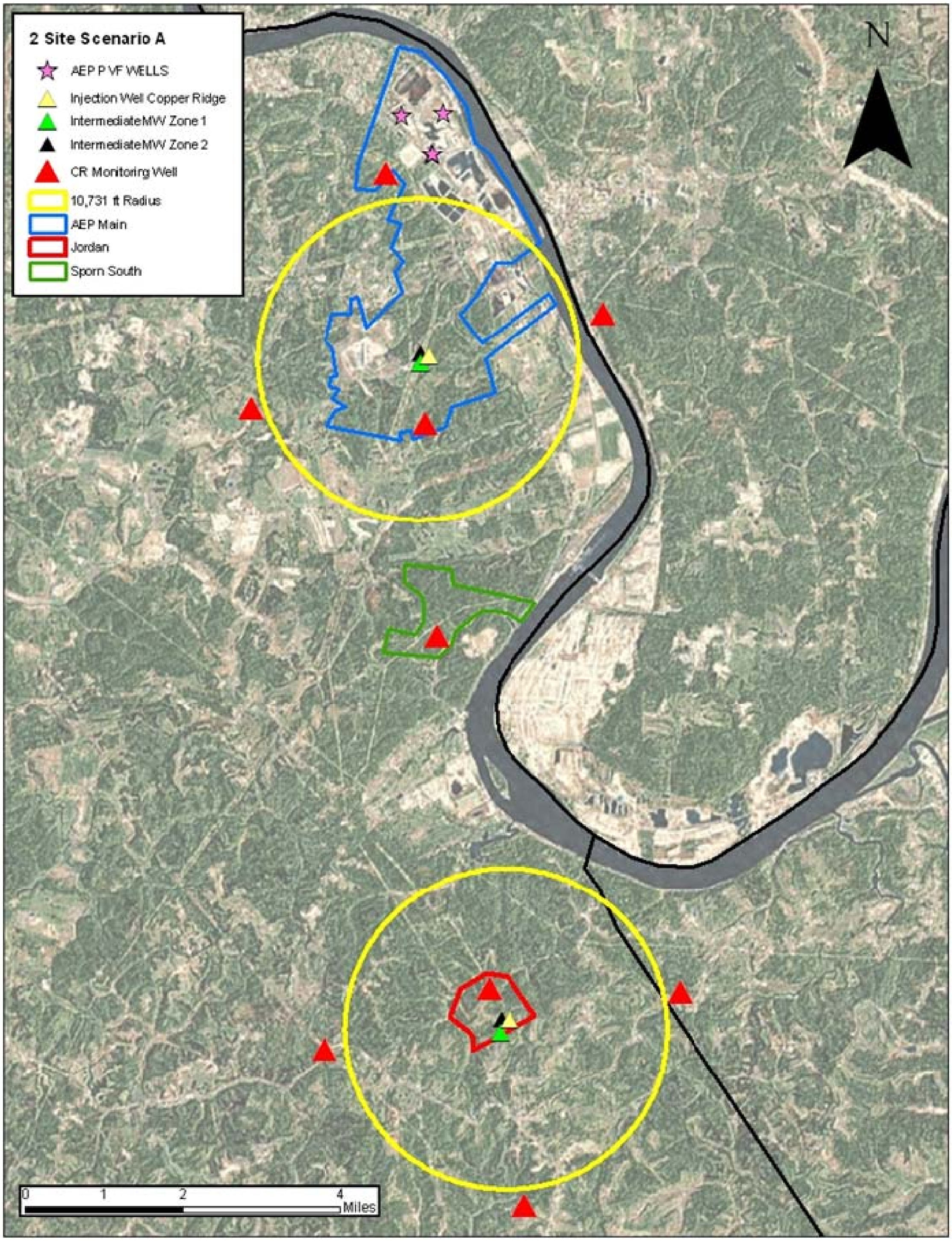


Figure 2-1. Location of CO2 Injection Sites. (Each of the Injection Sites Will Host A Rose Run Injection Well and a Copper Ridge Injection Well. Yellow Circles Corresponds to Estimated Size of CO2 Plumes in the Copper Ridge.)

injection wells include: AEP's Broad Run Landfill area (specifically the Borrow Area) and Jordan Tract. Western Sporn was originally included in the RFP and the draft environmental impact statement, but this site was not considered in this report because the site is occupied by wetlands and/or very steep topography, conditions that are not conducive for drilling. The Eastern Sporn Site was not included as one of the injection sites due to its proximity to the Borrow Area, which could have resulted in excessive CO2 and pressure overlap between the two sites.

In the simulation modeling, CO_2 was injected into the Copper Ridge Primary and Secondary Zones with a single well by assuming that the well was perforated across both zones. The amount of CO_2 that was injected into each zone was determined by the model and is a function of the permeability of the zone. Because the higher permeability Primary Zone overlies the lower permeability Secondary Zone, the majority of CO_2 enters the Primary Zone. The estimated plume size for each injection well at the end of 5 years of injection is given in Table 2-2. The size of the pressure-affected area is also given in Table 2-2. A cross-section illustrating the CO_2 plume at the end of 5 years of injection are shown in Figure 2-2.

Table 2-2. Estimated Radius of 3.75 MMT CO_2 Plume and Corresponding Pressure-Affected Area

	Assuming 2 Injection Sites	
Injection Zone	CO2 Radius[a] (ft)	Pressure Radius[b] (ft)
Copper Ridge – (Primary and Secondary Zones)	10,700	70,000

a. CO_2 radius after injecting 3.75 MMT CO_2 over a 5-year period (one half of the total CO_2 injection of 1.5 MMT/year)

b. Pressure-affected area assumes injection wells are shut down annually for two months to perform maintenance, which causes pressure front to recede slightly during this time.

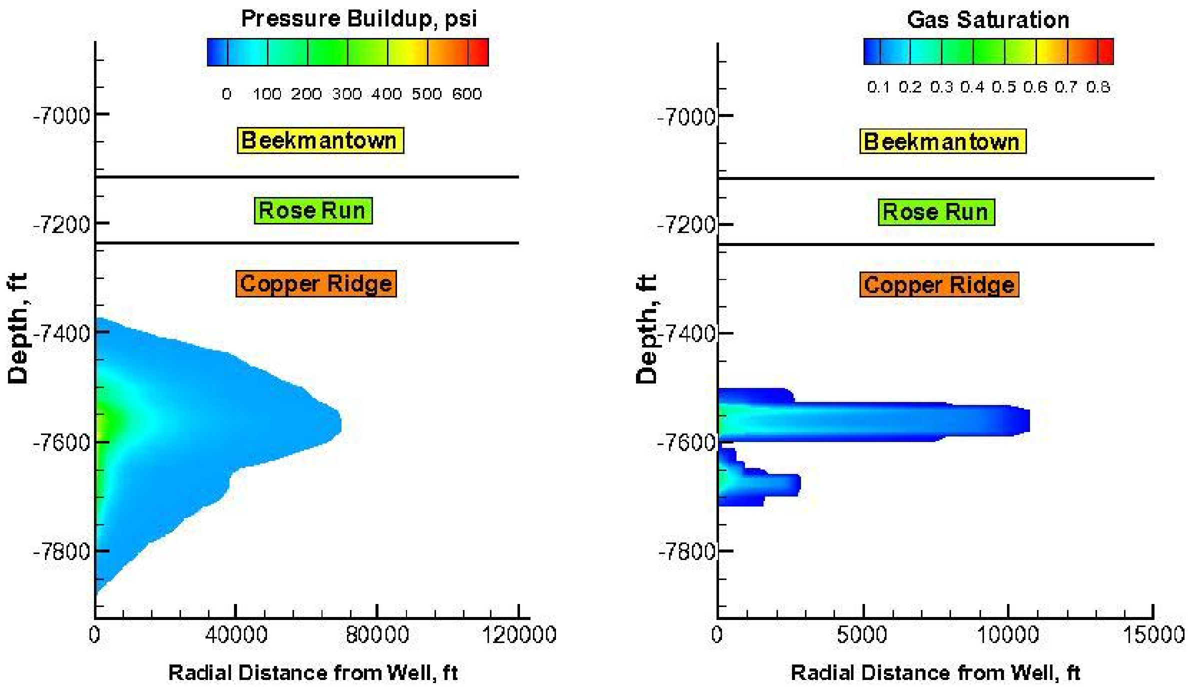


Figure 2-2. Cross Section of Pressure (left) and CO_2 Footprint (right) In the Copper Ridge After 5 years.

3.0 Monitoring and Testing Program Summary

This section provides a summary of the proposed testing and monitoring program for the planned commercial-scale project. A brief description of each monitoring method is provided in subsequent sections of this document. The terms *continuous* and *continuously* as used throughout this document are defined as a series of discrete measurements that are obtained at a frequency that is sufficient to meet the regulatory reporting requirements and/or project objectives; the frequency may vary depending on the monitoring method or technology.

3.1 Objectives and Methods

Table 3-1 summarizes the objectives and methods for a monitoring program that is based on the requirements of the UIC permit for the existing pilot-scale project.

Table 3-1. Monitoring Options and Objectives

Monitoring Objective	Method Summary	Section in This Report
Monitor the injection stream for chemical and physical characteristics	Collect periodic (quarterly) samples of CO_2 stream and analyze for composition.	Section 4
Monitor the injection operation and well annulus	- Continuously measure and record injection rate using real-time flow meters affixed to the CO_2 pipeline located just upstream of each well. - Continuously measure and record injection pressure and temperature using real-time meters affixed to each well. - Continuously measure and record pressure of the annulus fluid between the injection tubing and long-string casing using real-time meters affixed to each well. - Monitor annulus fluid volume added.	Section 5
Monitor corrosion of well materials	Monitor (quarterly) corrosion of well materials using coupons in contact with the CO_2 stream	Section 6
Demonstrate that injection wells have adequate external mechanical integrity	On an annual basis, conduct an oxygen-activation log, temperature log, or other tests (e.g., radioactive tracer survey) to evaluate external mechanical integrity of the injection wells.	Section 7
Assess long-term pressure build up in the injection reservoirs over time	Conduct a prolonged pressure fall-off test in the injection wells at least once every 5 years.	Section 8
Monitor groundwater qualify in the USDW aquifer(s)	Monitor groundwater wells completed in the Underground Source of Drinking Water (USDW) aquifers overlying the injection site(s) for chemical parameters that are indicators of CO_2 leakage and/or brine displacement.	Section 9

Monitoring Objective	Method Summary	Section in This Report
Monitor groundwater quality in Intermediate Water-Bearing Zone(s) Above the Confining Layer(s) for CO_2 leakage	Monitor deep wells completed between the confining layer(s) overlying the injection zone(s) and the Underground Source of Drinking Water (USDW) for chemical parameters that are indicators of CO_2 leakage and/or brine displacement and for pressure.	Section 10
Monitor the integrity of the caprock for injection induced fracturing that could result in CO_2 leakage across the confining layers	Monitor for induced seismicity using a monitoring method capable of detecting "micro" scale events.	Section 11
Track the extent of CO_2 and/or pressure in the injection reservoirs [a]	Conduct annual Pulsed Neutron Capture (PNC) and other wireline logging to determine the vertical distribution of injected CO_2 adjacent to monitoring wells that penetrate the injection reservoir.	Section 13
	Collect fluid samples from monitoring wells in the injection reservoir(s) and analyze for parameters that are indicators of CO_2.	Section 14
	Continuously monitor pressure and temperature in wells completed in the injection reservoir using sensors installed in the wells.	Section 15
	Conduct reservoir modeling – annually calibrate the reservoir model with results of pressure data and other monitoring results collected during the year so the model provides reliable predictions of CO_2 and pressure migration and behavior.	Section 16
Other requirements	Conduct surface air emissions monitoring to comply with the Greenhouse Gas Mandatory Reporting Requirements.	Section 17

a. Section 12 discusses geophysical (seismic) techniques that were evaluated for this purpose but determined to be not feasible or effective.

3.2 Monitoring Schedule

The monitoring program will begin with baseline monitoring that starts in Phase III (see Table 1-1) before CO_2 injection is initiated and continues through the 5-year active injection. Some monitoring would also continue after the end of the active injection phase (i.e., post-injection phase); however, post-injection monitoring is not discussed in this plan because it will occur after the DOE involvement in the project ends. A separate plan will be developed as part of the UIC permit application that addresses post-injection monitoring and site closure.

An anticipated monitoring schedule for a project having a 5-year active injection period is presented in Table 3-2. The schedule and types of monitoring options, other than those required under the UIC permit, are subject to modification based on several factors, including field observations, site logistics, budgets, and potential lessons learned at this site and others. Pre-injection monitoring is required to characterize baseline conditions that could be affected by the injected CO_2. The duration and complexity of pre-injection monitoring varies by monitoring method. For some of the monitoring techniques (e.g., PNC logging), a single sampling event (or survey) will be sufficient to characterize pre-injection conditions. For others, such as USDW groundwater monitoring, the baseline sampling program includes multiple sampling events across seasons to characterize variability in the target analytical parameters that will be monitored.

Table 3-2. Preliminary Monitoring Schedule for the Five-Year CO_2 Storage Project

Monitoring and Testing Methods	Base-line	Active Injection Phase Year 1	Year 2	Year 3	Year 4	Year 5
Quarterly sampling and analysis of the CO_2 injection fluid	NA	X X X X	X X X X	X X X X	X X X X	X X X X
Monitoring of injection rate volume, pressure, and temperature; annulus pressure and annulus fluid volume	NA	Continuous				
Corrosion monitoring of well materials	NA	X X X X	X X X X	X X X X	X X X X	X X X X
External mechanical integrity testing (MIT)	X	X	X	X	X	X
Pressure Fall-Off Testing	NA	X	X	X	X	X
USDW aquifer groundwater monitoring	≥1 year (quarterly)	X X X X	X X X X	X X X X	X X X X	X X X X
Groundwater quality and pressure monitoring in Intermediate Zone(s)	X	X	X	X	X	X
Microseismic Monitoring for Injection Induced Fracturing	≥1 month	Continuous				
PNC Logging for CO_2 Detection	X	X	X	X	X	X
Injection Reservoir Fluid Chemistry Monitoring	X	X	X	X	X	X
Injection Reservoir Pressure Monitoring	≥3 months	Continuous				
Modeling	X	X	X	X	X	X
Surface emissions monitoring	1 to 2 years[(a)]	X X X X	X X X X	X X X X	X X X X	X X X X

X: represents single sampling/survey event.
a. Quarterly or monthly frequency

4.0 Quarterly Analysis of the CO_2 Injection Stream

4.1 Purpose and Objectives

On a regular basis, samples of the CO_2 injection stream will be collected and analyzed for physical and chemical characteristics to monitor the composition of the injectate throughout the active injection phase of the project. This section describes the preliminary injection stream monitoring program.

4.2 Description

The preliminary product stream specification of the captured and compressed CO_2 is given in Table 4-1.

Table 4-1. CO_2 Injectate Specification

Constituent	Concentration – without chiller
CO_2	
Water (H_2O)	<3,000 ppmv
O_2	<250 ppm
Ammonia (NH_3)	<50 ppmv
Hydrogen Sulfide (H_2S)	-
Nitrogen (N_2)	<250 ppmv
Argon (Ar)	<10 ppmv
Temperature	90-110 degrees F
Pressure	3,000 psi

psi – pounds per square inch; ppm – parts per million mass; ppmv – parts per million, volume

Samples of the CO_2 stream will be collected quarterly and analyzed for chemical composition, including the parameters shown in Table 4-1. Samples will be collected at a location upstream of the compressor (pressure approximately 200 to 300 pounds per square inch [psi]) at a sampling station that will be installed by Alstom as part of the CO_2 capture system. The samples will be collected as a gas and either analyzed on site or shipped to a qualified off-site laboratory (i.e., WVDEP certified laboratory unless otherwise approved by WVDEP) for analysis.

4.3 Baseline Monitoring

Sampling of the CO_2 injection stream cannot begin until after the CO_2 capture and injection process is operational; therefore, there will be no baseline monitoring for the physical and chemical characteristics of the CO_2 stream. AEP will use online instrumentation and analyses of batch samples to ensure that the CO_2 product quality meets the parameters in Table 4-1 before injection commences. The data provided in Table 4-1 provide a range of baseline values describing the CO_2 stream.

4.4 Operational Phase Monitoring

During the period of active injection, sampling of the CO_2 injection stream will be conducted quarterly or at a similar frequency.

5.0 Injection Monitoring

5.1 Purpose and Objectives

Injection monitoring refers to the continuous monitoring of the following parameters associated with the CO_2 injection process: (1) flow rate and volume of the injected CO_2 stream; (2) pressure and temperature of the injected CO_2; (3) pressure of the annulus between the tubing and the long string of casing; and (4) annulus fluid volume losses.

5.2 Description

5.2.1 Continuous Monitoring of Flow Rate and Volume

Flow rate and cumulative mass will be continuously measured for each injection well using a flow computer that calculates flow rate from differential pressure measurements made with an orifice meter and temperature measurements made in the CO_2 pipeline just upstream of the orifice meter. Flow rate will be controlled with a valve that is operated remotely from the CCS Control Room or the local programmable logic controller (PLC) in the Well Maintenance and Monitoring System (WMMS) Building. Flow will be measured and controlled downstream of where the main pipeline enters the injection site well pod. Figure 5-1 illustrates the arrangement of the orifice meter, temperature indicator, and flow-control valve. The anticipated maximum daily CO_2 production (flow) rate is 4,839 metric tons per day (MT/D) (444,115 lb/hr[1]).

5.2.2 Continuous Monitoring of Injection Pressure and Temperature

Each injection well will be instrumented to continuously monitor and record the pressure and temperature of the CO_2 as it enters the well. Pressure and temperature sensor/transmitters will be located on the CO_2 pipeline near where it connects to the wellhead. Each sensor/transmitter will be connected to a remote terminal unit (RTU) that will be located in the WMMS Building. The RTU will allow temperature and pressure at each well to be viewed in real time. The temperature and pressure sensor/transmitters will also be connected to the CCS Control Room via the local PLC so that these parameters can be monitored in real time and logged into the data historian.

Injection pressure is one of the key parameters that will be used to initiate automatic shutdown of CO_2 injection if injection pressure exceeds the maximum bottomhole injection pressure (MBHIP) specified in the UIC permit. Therefore, bottomhole pressure will be monitored in real time and used to halt CO_2 injection if pressures exceed a pre-determined fraction of the MBHIP. Alternatively, if bottomhole pressure is not monitored in the injection wells, control logic will be developed that will halt CO_2 injection to a well if injection pressure (measured at the wellhead) exceeds a value that corresponds to the MBHIP. This value would be referred to as the

[1] Preliminary Design Guidelines for CO_2 Pipeline Transportation and Storage – Mountaineer Commercial-Scale Capture Project, American Electric Power, October 1, 2010

maximum allowable surface injection pressure (MASIP). Automatic shutdown will be accomplished by closing the flow valve to the well (e.g., Flow Valve in Figure 5-1) and the remotely-actuated valve on the well tree. Each injection well will be equipped with one remotely-actuated valve that can be operated from the CCS Control Room.

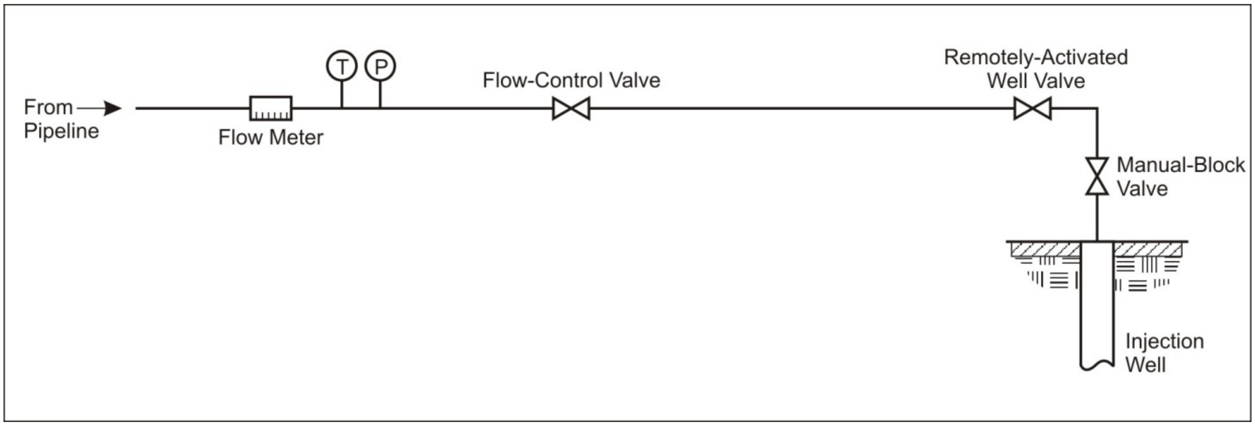


Figure 5-1. Schematic illustrating Arrangement of Flow Measurement and Control Devices for a Typical Injection Well. Orifice Meter, Pressure Sensors (pressure and differential pressure), Temperature Sensor and Flow Valve.

Anticipated operating temperatures are provided in Table 5-1. Operating pressures will depend on the desired flow rate, well characteristics, and limitations specified in the UIC permit.

Table 5-1. Anticipated Operating Temperatures and Pressures

Parameter	Design
Temperature (Compressor Outlet)	80°F to 115°F
Temperature (Wellhead)	40°F to 115[(a)]
Injection Pressure (Wellhead)	Varies with flow rate/well

(a) Low temperature is due to above ground piping between the plant/capture unit and near the Borrow Area.

5.2.3 Continuous Monitoring of Annulus Pressure and Volume

For each injection well, annulus pressure (i.e., pressure of the annular fluid between the injection tubing and the long string casing) will be continuously measured and logged using a pressure sensor/transmitter installed on the wellhead. Each sensor/transmitter will be connected to the RTU that will be located in the WMMS building. The RTU will allow annulus pressure along with injection pressure and temperature at each well to be viewed in real time. The annulus pressure sensor/transmitter on each well will also be connected to the CCS Control Room via the PLC in the WMMS Building so that this parameter can be monitored in real time and logged on the data historian.

Control logic will be developed that will trigger alarms and/or halt CO_2 injection to a well if annulus pressure suggests failure of internal mechanical integrity (e.g., tubing leak). Flow can be halted automatically by closing the flow valve to the well and the remotely-actuated valve on the well as shown in Figure 5-1. As stated previously, each injection well will be equipped with one remotely-actuated valve that can be operated remotely from the CCS Control Room.

The well annulus will contain a non-corrosive annular fluid and will be maintained at a pressure above the CO_2 injection pressure throughout the injection process. The pressure on the annular fluid will be maintained at the level(s) specified in the final UIC permit using the WMMS that has been designed for this purpose. The WMMS includes high-pressure accumulators containing the annular fluid that is connected to the well annulus via a small-diameter stainless steel line. Pressure is maintained on the fluid in the accumulators via pressurized nitrogen. Because the line connecting the high-pressure accumulators and the well annulus has no valves, the surface annulus pressure in the well equalizes to the pressure in the accumulators. The system also includes a 200 gallon backup tank that contains a reserve volume of annulus fluid in case the accumulator connected to the well becomes depleted. Fluid can automatically be pumped from the reserve tank into the accumulators when the fluid level in the accumulators falls below a pre-set level. During injection operations, the fluid level in the backup tank will be monitored; also, any time fluid is added to the tank, the volume of fluid added will be recorded. This will provide a means for monitoring annulus fluid volume.

5.3 Baseline Monitoring

Baseline monitoring activities will entail installing the equipment and instrumentation necessary to monitor injection operations, including: (1) continuous monitoring of flow rate and volume of the injected CO_2 stream; (2) continuous monitoring of the pressure and temperature of the injected CO_2; and, (3) continuous measurement and recording of the pressure on the annulus between the tubing and the long string of casing. All equipment and instrumentation will be tested to verify it is functioning properly. Collection of operational data cannot begin until after injection begins. Therefore, final testing of the system will need to occur in conjunction with the start of injection.

5.4 Operational Phase Monitoring

During the period of active injection, the operating parameters will be monitored at the frequency described previously unless otherwise required. Injection parameters including injection flow rate, pressure and temperature and annulus pressure will be monitored in the CCS Control Room by the system operator(s). Furthermore, the system has been designed with controls that will make adjustments to the injection rate and pressure, including halting injection completely if necessary, if pre-determined limits on injection pressure or annulus pressure are exceeded.

6.0 Corrosion Monitoring

6.1 Purpose and Objectives

Monitoring corrosion of well materials will be conducted using the corrosion coupon method. However, visual inspections for evidence of corrosion will also be conducted whenever the tubing is removed from the injection wells (e.g., during maintenance and/or well workovers). This section discusses the coupon method for corrosion monitoring.

6.2 Description

Corrosion monitoring of well materials will be conducted using coupons placed in the CO_2 pipeline (Figure 6-1). The coupons will be removed periodically (quarterly) and assessed for corrosion using United States Environmental Protection Agency (U.S. EPA) SW846 Method 1110A – "Corrosivity Toward Steel", or a similar standard method. This method measures the corrosivity of steel of both aqueous and non-aqueous liquid wastes. Upon removal, coupons will be inspected visually for evidence of corrosion (e.g., pitting). The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed. Corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

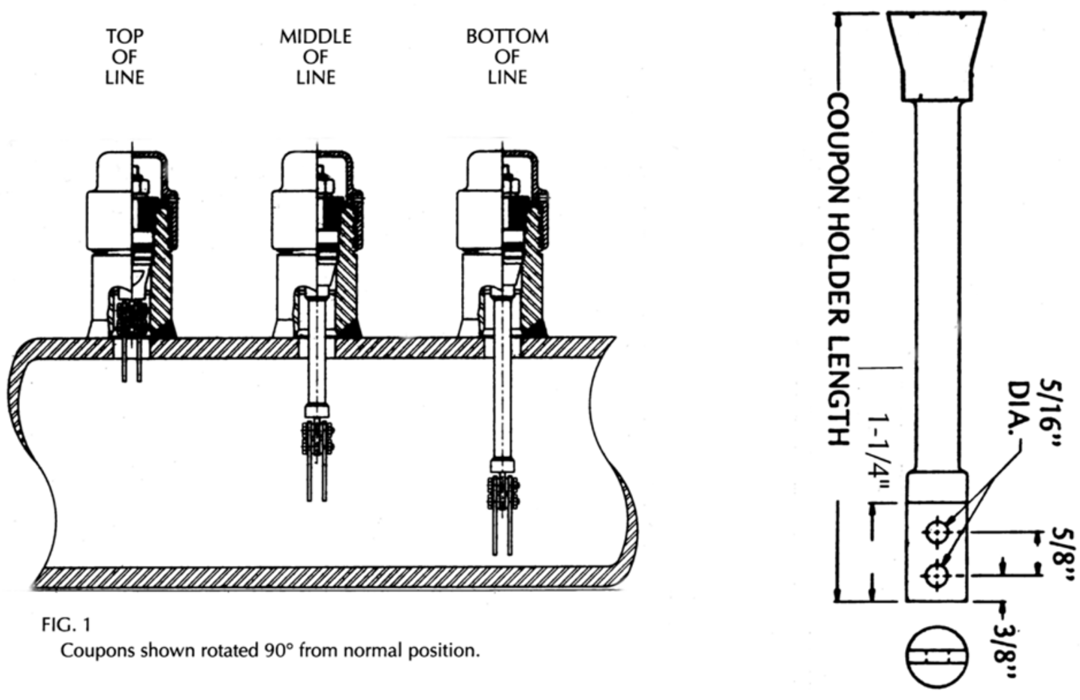


Figure 6-1. Corrosion Coupon Illustration in Pipeline (Source: Rohrback Cosasco Systems, Inc.)

6.3 Baseline Monitoring

Baseline monitoring activities will include installing the equipment (COSASCO Model 6200 two-inch system coupon holders (or equivalent) needed to monitor corrosion and preparing coupons of well materials. At least one coupon holder will be installed at each injection site to monitor corrosion of well materials. They will be installed in the CO_2 pipeline just downstream of the flow measurement and control devices (i.e., near the wellhead) to ensure that they are located where corrosion conditions are most representative of the conditions in the well. Corrosion coupons will be made from materials used for the injection tubing and/or casing in each well.

6.4 Operational Phase Monitoring

During the active injection period, the coupons will be removed at a regular frequency (e.g., quarterly) and assessed for corrosion.

7.0 External Mechanical Integrity Testing

7.1 Purpose and Objectives

An injection well is considered to have mechanical integrity if the following two conditions are met (40 CFR § 146.8) (US Code of Federal Regulations, Title 40, Part 146).

(1) there is no significant leak in the casing, tubing or packer; and,

(2) there is no significant fluid movement into an USDW through channels adjacent to the injection wellbore.

The first condition is referred to as internal mechanical integrity; the second condition is referred to as external mechanical integrity. This section describes methods that will be used to evaluate the external mechanical integrity of the injection wells.

7.2 Description

The methods that will be employed are a differential temperature survey or a radioactive tracer (RAT) survey. These two methods may be used separately or in conjunction with each other.

7.2.1 Temperature Logging

Temperature logging is a common means of identifying fluids which have moved along channels adjacent to the wellbore. In addition to identifying injection related flows behind casing, temperature logs can often locate small casing leaks. They can also be used to monitor fluid movement through the confining zone adjacent to the wellbore (inter-formational flows).

Injection of CO_2 will have a cooling or heating effect on the natural temperature in the storage reservoirs, depending on the temperature of the injected CO_2 and other factors. Natural bottom-hole temperatures in the Rose Run and Copper Ridge Formations are expected to be approximately 150°F based on temperature logging conducted in AEP-1 during drilling; whereas, the temperature of the injected CO_2 is anticipated to be on the order of 115°F at the surface (this is the design temperature of the CO_2 exiting the compressor/pump). The greater the temperature difference between the CO_2 when it reaches the injection zone and the ambient reservoir temperature, the easier it will be to detect temperature anomalies due to leakage behind casing.

The following conditions will be employed when conducting temperature surveys.

- The log will be run over the entire interval of cemented casing, logging down from the surface to total depth;

- Temperature logs will include both an absolute temperature curve and a differential temperature curve;

- Temperature logs will be run going into the well to minimize the smeared response caused by logging line and tool movement; the temperature sensor will be located as close to the bottom of the tool string as possible;

- The temperature log will be conducted through the injection tubing, if possible;

- The temperature log will be scaled between 1°F to 10°F per; the differential curve may be scaled in any manner appropriate to the logging equipment design, but will be sensitive enough to readily indicate anomalies;

- Line speed will be limited (e.g., approximately 30 ft per minute or less); the logging speed shall be kept constant for all sequential passes;

- For flowing surveys, injection will be stabilized prior to running the survey (e.g., for at least several hours prior to running the surveys); and,

- For shut-in (i.e., no injection) surveys, the well will be shut-in for several hours to allow for temperature stabilization.

7.2.2 Radioactive Tracer Survey

A RAT survey is a method for tracking the downward movement of the injected fluid through the well and determining the location(s) (e.g., perforations, leaks through casing) where it exits the well. RAT surveys can also detect fluid movement in vertical channels adjacent to the well. RAT surveys are conducted during injection (i.e., through tubing); however, the injection rate must be limited to a low flow rate so that flow is laminar and detection of the radioactive tracer is possible with the wireline tool.

A RAT survey may be conducted in one of two ways. The first way is referred to as slug tracking. In this method, a small slug (typically about 100 mls) of radioactively tagged brine (Iodide 131, a gamma-ray emitter, is the most commonly used radioisotope for this purpose) is ejected from the RAT tool and released into the well at a pre-determined depth, usually some distance above the well perforations, while the well is injecting at a low rate. Upon release, the slug begins to move downward into the well toward the perforations. As the slug moves downward in the well, the tool, which is equipped with two gamma detectors (only one is used for this type of test), is repeatedly lowered and raised through the slug to detect and track the position of the radioactive slug over time (i.e., by measuring gamma ray intensity). As the slug moves out of the wellbore through the perforations and horizontally away from the well, the vertical position of the slug will remain relatively constant until eventually the slug moves far enough away from the well that it can no longer be detected. However, if vertical flow channels exist outside the wellbore, the slug would appear to move up over time instead.

The second method for conducting a RAT survey is the shot method. In the velocity shot log, a small quantity (shot) of radioactive tracer is ejected and the time required to travel between the two detectors on the tool is measured. These time measurements are converted to fluid velocities, then to an injection profile. For an injection well, the preferable method is to have the tool arranged such that the two gamma ray detectors are below the ejector section; the time of tracer travel between detectors is then easily measured on a time drive chart.

7.3 Baseline Testing

For temperature logging an initial (baseline) temperature survey will be conducted prior to the start of injection to determine the baseline (ambient) static temperature gradient of the earth in each injection well. The baseline temperature survey will provide a basis against which future temperature logs can be compared.

There is no baseline performed for the RAT.

7.4 Operational Phase Testing

Table 7-1 summarizes the proposed test methods and their frequencies during the operational phase.

Table 7-1. Summary of Proposed Methods and Test Frequency for Demonstrating Injection Well External Mechanical Integrity

Requirement	Test Method	Frequency
External Integrity Demonstration	Temperature Logging/Survey	Annually after injection begins. A baseline temperature survey will be conducted prior to injection to establish baseline conditions.
	Radioactive Tracer Survey	Instead of or in addition to the temperature survey.

8.0 Pressure Fall-Off Testing

8.1 Objective

Increased hydrodynamic pressures are created in geologic reservoirs as a result of the injection of fluids through wells. Pressure fall-off tests are used to test wells that have been injected into for some time in order to estimate the following:

- long-term pressure build up in the injection reservoir(s) over time;
- average reservoir pressure obtained through this testing can be compared to modeled predictions of injection interval pressure, thereby allowing a means for validating models used to predict CO_2 and pressure extent;
- reservoir characteristics including transmissivity, permeability, storativity as well as changes in these parameters over time; and,
- formation damage (skin) near the wellbore, which can be used to diagnose the need for well remediation/rehabilitation.

8.2 Description

In the pressure (injection) fall-off test, flow is maintained at a steady rate for a period of time, then injection is stopped, the well is shut in, and bottom-hole pressure is monitored and recorded. Figure 8-1 is an example pressure data set from an injection fall-off test.

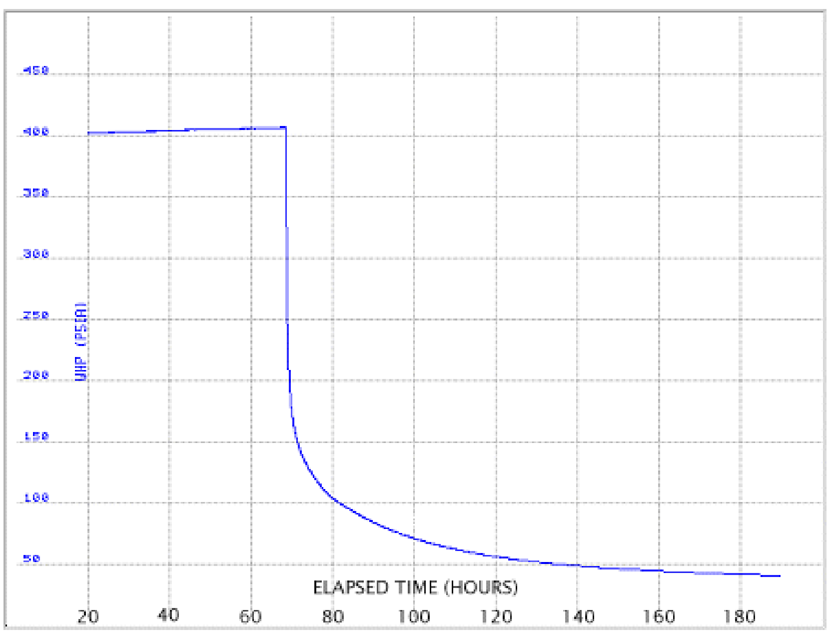


Figure 8-1. Example Pressure Fall-Off Test

A steady injection rate should be achieved throughout the pre shut-in injection period. The pre shut-in injection rate should be maintained for sufficient time (e.g., 24 to 48 hours) to ensure representative test data are obtained. The fall-off period should be sufficiently long enough to observe radial flow into the well. This would be indicated by a straight line on a semi-log plot or a flat line on a log-log plot of the pressure derivative.

8.3 Baseline Testing

Not applicable.

8.4 Operational Phase Testing

During the period of active injection, pressure fall-off testing will be conducted at least once every 5 years to provide information on the condition of the CO_2 injection reservoirs. In the years when a pressure fall-off test is required, it will be planned/coordinated to occur in conjunction with the annual monitoring and external mechanical integrity testing for that year. Fall-off tests will be conducted with CO_2 from the carbon capture system. Pressure measurements will be obtained using a bottom-hole pressure sensor installed in the injection well(s) and/or surface sensor/transmitters installed specifically for the test. If surface pressure data are used in data analysis, they will be corrected to bottom-hole pressure before using the data.

Data analysis will entail plotting and analyzing pressure data using standard well-analysis methods. Plots will include, for example: graphs on Cartesian plots of injection rate versus time and plots to clearly show pressure relationship with time; plots of the log of pressure change versus the log of time change with the log of the pressure derivative with respect to time and semi-log plots with a best-fit straight line indicating the period of radial flow. An example log-log plot is provided in Figure 8-2. In addition to radial flow regime, other flow regimes may be observed from the fall-off test, including: spherical flow, linear flow, and fracture flow. The late time responses correlate to distances further from the test well.

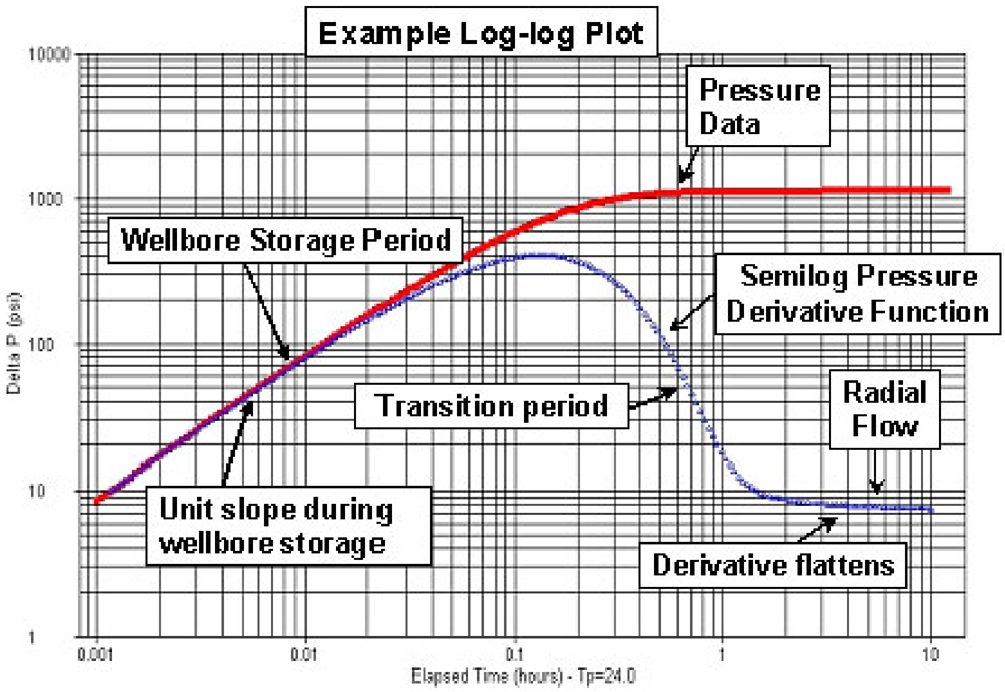


Figure 8-2. Example Log-Log Plot of Pressure Data from Fall-Off Test (Source: U.S. EPA, 2002)

9.0 Groundwater Monitoring of the USDW Aquifer

This section describes the preliminary groundwater monitoring program for the Underground Source of Drinking Water (USDW) aquifer(s) that overlie the commercial-scale project injection sites. The USDW groundwater monitoring program involves repeated collection of water samples before and after the initiation of CO_2 injection from wells completed in the USDW aquifer(s) above the injection site and analysis of the samples for chemical parameters that are indicative of CO_2 or brine invasion.

9.1 Purpose and Objectives

Monitoring groundwater wells in the USDW aquifer(s) above the injection site(s) is required for detecting upward migration of CO_2 or brine out of the injection zones and to ensure protection of the USDW aquifers. The method relies on the ability to detect geochemical changes in water quality in the shallow groundwater zone due to the presence of CO_2 or brine.

9.2 Description of USDW Aquifer(s)

In order to determine the depth of the USDW aquifers in the vicinity of the injection sites, data from 42 wells in Mason County, WV were evaluated. Figure 9-1 shows the locations of the wells used in the evaluation and the location of the proposed CO_2 injection sites. The evaluation, which is based on observational data taken from drilling logs, indicated that the depth of fresh water in this region may range from 10 to 710 feet below ground surface (bgs); and, the top of the first saline aquifer may range from 535 to 1,757 feet bgs.

The maximum depth of the base of the lowermost USDW aquifer is estimated to 700 feet bgs This will need to be confirmed when drilling wells at the injection sites.

9.3 Monitoring Well Design and Placement

The USDW aquifer(s) at each injection site will be monitored by installing four monitoring wells in the vicinity of each injection site One well will be placed in close proximity to the injection well (e.g., within 500 feet). This well will allow for monitoring of the USDW aquifer(s) near the injection well and will be used to monitor for leakage in the immediate vicinity of the injection well where reservoir pressure is likely to be highest. The other three wells will be installed in a triangular pattern, each approximately ¼ mile from the injection well. This configuration allows for more distant monitoring of the USDW aquifer and for determination of groundwater flow direction in the area overlying the CO_2 plume. Two of the wells will be placed hydraulically downgradient of the injection well, and a single well will be placed hydraulically upgradient of the injection well. This well configuration will allow for determination of the groundwater flow direction and will provide additional background data for the drinking water reservoir.

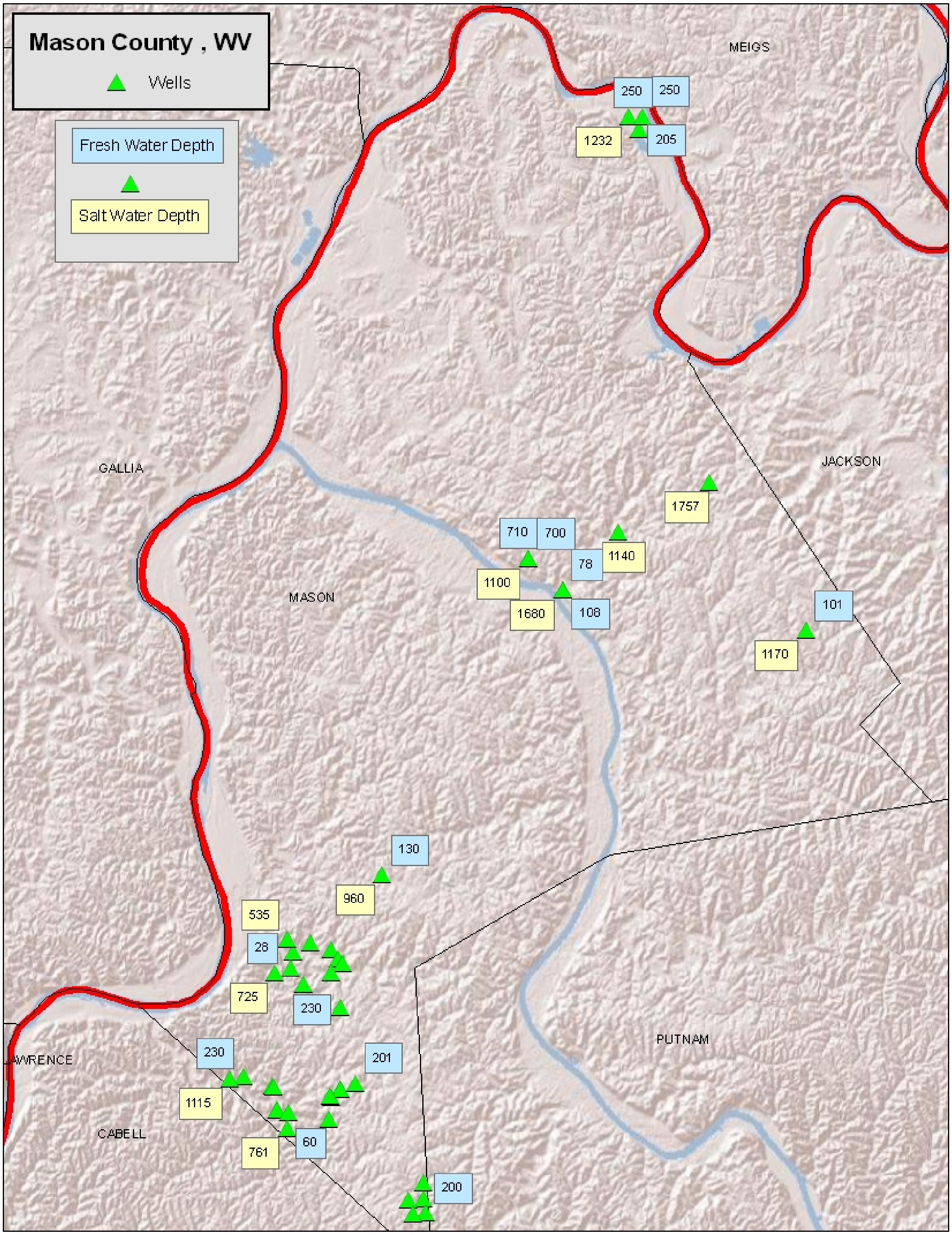


Figure 9-1. Location of Oil and Gas Wells in the Vicinity of the Proposed Injection Sites With Observational Data on the Depth of Freshwater and Saline Water.

Additional wells may be installed if necessary to monitor preferential leakage pathways, such as fractures that could intersect the injection reservoir. The USDW aquifer monitoring wells will be designed to monitor fresh water zones above a depth of 700 feet bgs.

9.4 Analytical Program

Groundwater samples will be analyzed for chemical parameters that are indicative of the presence of CO_2 or brine invasion. Table 9-1 lists the analytical parameters for inclusion in the groundwater monitoring program. Potential short-term chemical changes due to CO_2 migration that may be detectable using fluid chemistry include: decreased pH caused by dissolution of CO_2; potential dissolution of carbonate minerals (carbonate and dolomite) by acidic fluids and corresponding increase in alkalinity; mineral dissolution producing an increase in TDS due to an increase in cations such as Ca^{+2} and Mg^{+2}, and increased concentration of acid-soluble metals such as iron and manganese. The influx of brine water would be indicated by increased TDS in general, and specifically increases in sodium and chloride concentrations. Isotopes may be helpful in distinguishing the injected CO_2 from other sources of CO_2, such as biogeochemical sources.

Table 9-1. Analytical Parameters for Shallow Groundwater Monitoring

Cations	Anions	Physical Parameters	Other
Potassium Sodium Calcium Magnesium Iron Manganese Aluminum Barium Boron Lithium[(b)] Strontium Dissolved Silica	Chloride Sulfate Bromide Fluoride	pH[(a)] Alkalinity (Bicarbonate) Alkalinity (Carbonate) Total Dissolved Solids Specific gravity/ Density Dissolved Organic Carbon Specific conductance[(a)] Temperature[(a)] Turbidity[(a)]	Stable hydrogen isotopes (D/H) Stable oxygen isotopes (^{18}O /^{16}O) Stable carbon isotopes ($^{13}C/^{12}C$) Dissolved CO_2 Tracers

(a) Field parameter

9.5 Baseline Monitoring

The USDW aquifer monitoring wells will be installed at least two years prior to the start of CO_2 injection to assess background water quality data. Water samples will be collected on a quarterly basis and analyzed for the parameters listed in Table 9-1. Prior to the collection of the quarterly groundwater samples, static water levels will be measured in each of the wells to develop water table maps and monitor the groundwater flow direction.

9.6 Operational Phase Monitoring

After injection begins, groundwater monitoring will continue using the same wells and at the same frequency (i.e., quarterly) during baseline monitoring. Groundwater samples will be collected using the same methods that are employed during the baseline sampling period and will be analyzed for the same target analytes that are monitored during the baseline period. Using the same sampling and analytical methods will allow for direct comparison of the analytical results to determine if the CO_2 injection is affecting the USDW aquifers(s).

10.0 Groundwater Monitoring of Intermediate Water-Bearing Zone(s) Above the Confining Layer(s)

10.1 Purpose and Objectives

Monitoring groundwater in one or more zones between the confining layer(s) overlying the injection zone(s) and the Underground Source of Drinking Water (USDW) aquifers is required by the new GS Rule. The intended purpose of this type of monitoring is to detect CO_2 leakage out of the injection reservoir(s) before it impacts the USDW aquifers.

10.2 Description

Figure 10-1 is a stratigraphic column for the injection sites. Candidate intermediate zone(s) to be monitored for evidence of CO_2 leakage across the caprock and confining units include the Clinton Formation, Berea Formation, and the Sharon Sandstone. For the sake of this preliminary MVA plan and the Phase I cost estimate, it is assumed that one intermediate well will completed in each of the two deepest zones – the Clinton Sandstone and the Berea Sandstone – at each injection site. Each well would be perforated in the target formation and completed with a tubing and packer system to facilitate periodic fluid sampling. In addition, the wells would be completed with pressure and temperature gauges (either real-time or memory gauges) to allow continuous monitoring of pressure and temperature.

Fluid samples would be analyzed for chemical parameters that are indicators of CO_2 leakage and/or brine displacement. An example analytical suite is given in Table 10-1.

Table 10-1. Analytical Parameters for Monitoring Groundwater Chemistry of Intermediate Zones

Cations	Anions	Physical Parameters	Other
Potassium Sodium Calcium Magnesium Iron Manganese Aluminum Barium Boron Lithium[(b)] Strontium Dissolved Silica	Chloride Sulfate Bromide Fluoride	pH[(a)] Alkalinity (Bicarbonate) Alkalinity (Carbonate) Total Dissolved Solids Specific gravity/ Density Specific conductance[(a)] Temperature[(a)] Turbidity[(a)]	Stable hydrogen isotopes (D/H) Stable oxygen isotopes (^{18}O / ^{16}O) Stable carbon isotopes (^{13}C/^{12}C) Dissolved CO_2 Tracers

(a) Field parameter

(b) Analysis for CO_2 will be performed only if a sample is collected with a downhole sampling device that preserves the sample at ambient pressure. Swabbing will not provide representative results for dissolved gases.

10.3 Baseline Monitoring

Baseline monitoring will involve collection and analysis of at least one round of groundwater samples from each well before CO_2 injection begins. If time allows, additional samples should be collected. Background pressure monitoring will be conducted for at least one month.

10.4 Operational Phase Monitoring

After CO_2 injection begins, fluid monitoring will be conducted on a regular frequency – e.g., quarterly – to assess the potential for upward leakage of CO_2 out of the injection reservoir. Additional interim sampling could also be conducted if a leak is suspected based on pressure data from the wells or other evidence – such as surface seismic monitoring data (see Section 11).

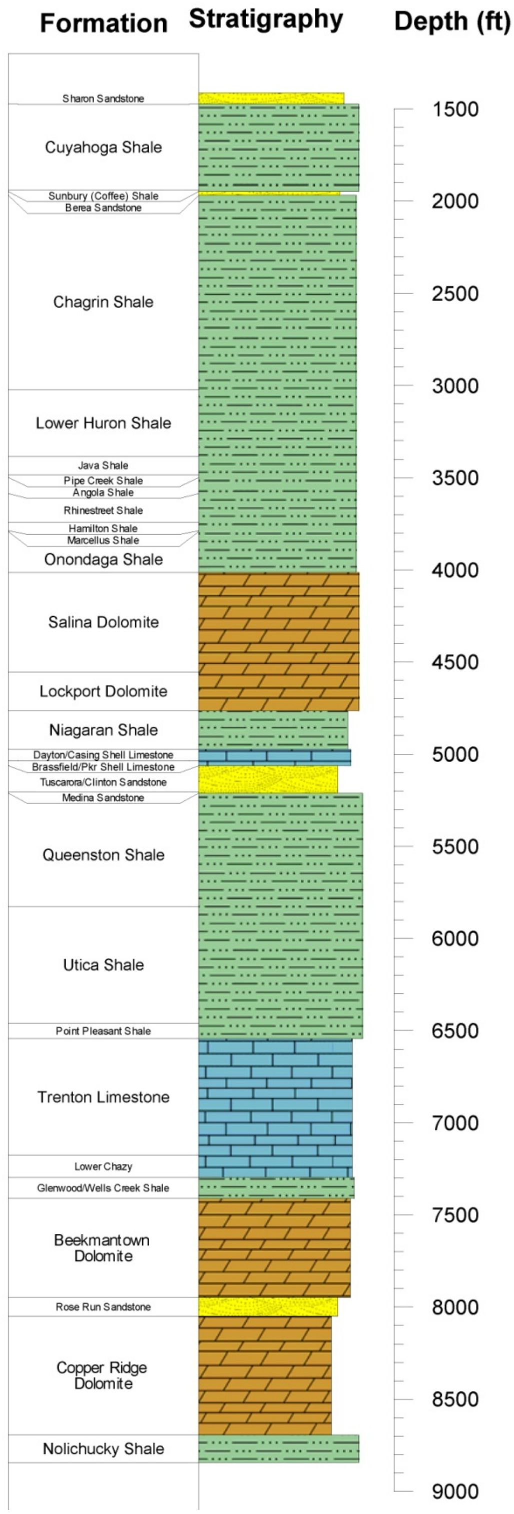


Figure 10-1. Geology of the Injection Sites (Based on BA-02 Well) Showing the Clinton, Berea, and Sharon Sandstones.

11.0 Surface MicroSeismic Monitoring

11.1 Purpose and Objectives

The objective of installing a surface microseismic monitoring system is to monitor the caprock for events that could indicate fracturing that may provide paths for CO_2 to migrate from the injection zone thru the confining layers to shallower geologic formations. By recording continuous seismic data, any events occurring in the caprock or any larger events in the injection reservoir will be detected. A secondary purpose of microseismic monitoring that will be explored is the capability to detect fluid substitution and the pressure front in the injection layer to monitor and track the CO_2 during injection. This will be done within the instrumentation detection limits.

11.2 Description

Surface microseismic is an alternative to down hole microseismic monitoring. For surface microseismic, a two-dimensional (2D) array of sensitive geophones are buried in a borehole drilled into bedrock. A typical installation has about 30 - 100 borehole sensor locations recording over the area for each injection well. Figure 11-1 shows the minimum installation grid (the violet circles filled with orange, one-mile spacing, 24 sites per well) and the maximum (adding the unfilled violet circles, one-half mile spacing, total 70 sites per well). Depending on local geology, noise and depth, this technology has the potential to measure microseismic events with a magnitude of minus 2 on the movement magnitude scale within the boundary of the sensor array. A full modeling study is needed to trade the sensor spacing with depth sensitivity for the region. The primary advantage of this approach over the deep downhole microseismic method is that a deep well(s) is not required. The monitoring equipment and installation cost for surface seismic monitoring are expected to be less than the cost of a well. Also, this method can be easily expanded and at a lower cost as the CO_2 plume grows.

By having an array of receivers distributed throughout the region, an isolated microseism will reach each receiver at slightly different times. Reconciling the arrival time differences among the various receivers in the array makes it possible to determine the location of the event. The accuracy improves when more time differences are used to solve for the location of the microseism. As a general value, an event can be located to within about ±25 feet with varying degrees of confidence.

The ability to detect low level events comes from processing a large number of signals. At each surface monitoring location, from multiple tri-axis geophones would be installed inside of a borehole for noise cancelation. For noisy environments such as the site selected, three tri-axis geophones separated by 50 feet are used to help reduce surface noise. The problems with unreliability of deep downhole microseismic instrumentation can circumvented since failed nodes can be repaired one at a time. Another advantage is that surface microseismic does not interfere with injection or well operations such as tubing removal, workover, down hole gage retrieval, etc. However, this type of system can be subject to vandalism and environmental problems such as flooding.

The boreholes for the geophones can usually be made with water well drilling equipment. The borehole is typically cased with plastic (PVC) pipe. At the surface, there would be a data recording station, with a footprint of approximately 4 feet square. Approximately 10 gigabytes of uncompressed data is recorded from a single 3 axis geophone in a week. The data for each of the sites will have to be collected and loaded onto a common data server. The data upload can be done automatically (remotely) through radio, cell phone or satellite data links or manually by collecting the data memory cards from each location on a monthly basis. Third party vendors provide processing as a service at typical engineering consulting rates with an estimate of five days per month. The amount of activity in the area will define the processing budget for both approaches.

Locating the monitoring stations is an important factor to reduce noise and vandalism. Locating a station far from roads removes the station from a large source of noise and places it out of sight from curious people. These stations require power, which can usually be accomplished using solar panels. If the monitoring locations are wooded, a clearing will be needed for solar power. A box with data recording equipment, GPS clock, and batteries will sit on the surface. A fence will surround the installation to help deter vandalism. A local contractor can be used to clear the site, provide adequate drainage, dig the sensor holes and install fencing. The seismic equipment suppliers would supervise site preparation and install monitoring equipment.

In addition to detecting injection induced fracturing, surface microseismic arrays have the potential to be used to monitor the movement of the CO_2 plume. However, this is a function of the geology of the injection layer and it is not known whether the events are caused by fluid movement or the pressure wave from injection. Either of these events will be significantly below the signals that fracture will produce and it is difficult to predict whether these events will have sufficient energy to be detectable prior to injection.

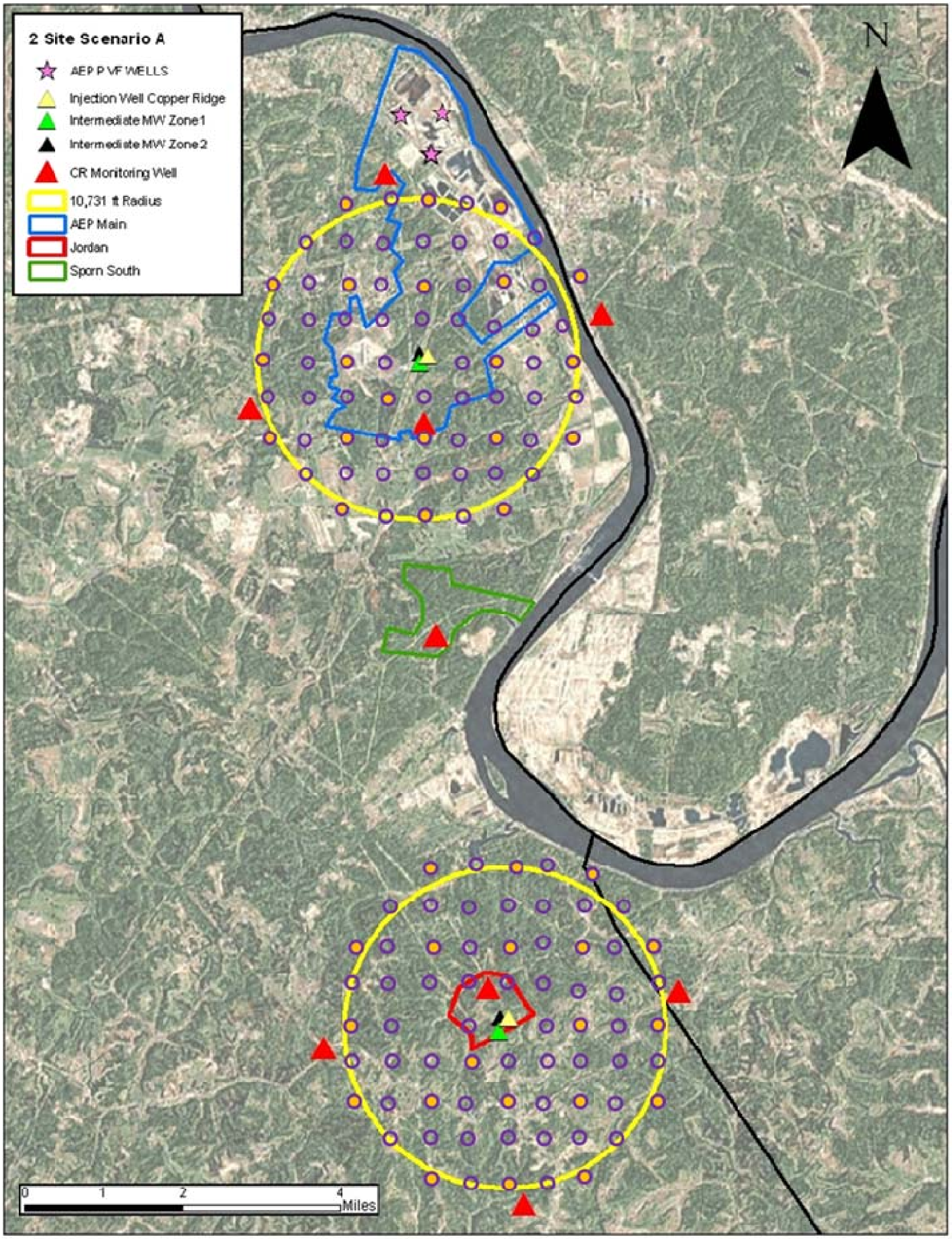


Figure 11-1. Minimum Installation Grid (Violet circles filled with Orange, One-Mile Spacing, 24 sites per well) and the Maximum (Plus Unfilled Circles, One-Half Mile Spacing, total 70 Sites per Well).

11.3 Baseline Monitoring

The key to microseismic assessment is event location, which is accomplished with array of sensors and rigorous signal processing software. The sensor array will have to be calibrated with events of similar magnitude at the critical depth. The easiest method for calibration is to use well perforation shots in the injection and monitoring wells. If perforations are completed prior to array installation, small charges (about the size of a fire cracker) in the intermediate and monitoring wells on site can be used. In the vicinity of the injection sites, there are many surface event sources as well as subsurface event sources from nearby mining operations including blasting. Mine blasts can be useful for refining location processing procedures, if the blast location is known, but frequent mine blast can increase processing costs.

Data must be collected and processed prior to the start of CO_2 injection to establish the baseline activity for the area. A typical baseline monitoring event will last one to two months, depending on how much background activity there is in the region. Additional baseline data can be collected during extended outages if necessary.

11.4 Operational Phase Monitoring

Microseismic data will be collected continuously over the entire operational phase. The processing of the signals will be performed by a third-party contractor that specializes in seismic-data processing. Processing would be conducted on a regular basis such as weekly, to detect microseismic events. Decisions about the potential fracture initiation or growth will not be made on the occurrence of a single event. A series of events in a specific region over a period of time is needed to identify areas of potential fracture initiation or growth. It is anticipated that 3 to 5 percent of the monitoring stations will require maintenance each year. This can be performed during injection periods.

12.0 Repeat Seismic Monitoring

At this time, no form of repeat seismic is being proposed for CO_2 plume tracking for the Mountaineer II CSP. Based upon results of the crosswell seismic survey at the pilot-scale project, the depth of the Copper Ridge and the thin injection intervals, it does not appear that seismic monitoring is a suitable CO_2 plume tracking technology for this site. The recommendations are based on a feasibility study conducted by Bob Hardage, a recognized expert in the area of seismic monitoring. A brief discussion is provided below for each type of seismic monitoring that was considered.

12.1 Repeat 3-D Surface Seismic

Repeat 3-D surface seismic (i.e., 4-D seismic) is not being recommended at this site for the purpose of CO_2 plume tracking. The reason for this is twofold: 1) prohibitive cost and 2) inability to reliably detect CO_2. For the size of the area that would need to be surveyed to track the CO_2 plumes at this site, the cost of each survey would be several million dollars and could take several months to acquire. Furthermore, surface cover in the vicinity of the injection sites is predominantly forest, making the survey more difficult and time consuming. The time alone would either require either extended shutdown of injection operations or the results would reflect changes occurring during acquisition, thus complicating the images.

From a technical standpoint, the combination of the great depth and small thickness of the injection target as well as the frequency of a surface source makes imaging changes due to CO_2 unlikely. A typically surface seismic source puts out energy from approximately 10 Hz to about 200 Hz. Typically, surface seismic resolution for reflection imaging may be as low as approximately 25 ft and for tomography as low as approximately 100 ft in a best case scenario. This makes imaging the thin vugular zones within the Copper Ridge that are likely to store the CO_2 unlikely. In addition, any injection related changes in these small intervals will create corresponding small changes in velocity. It is anticipated that these changes will be too small to be resolved with surface seismic.

Although surface seismic is unlikely to produce useful results for plume tracking, it remains very useful for characterization. The vugular zones in the Copper Ridge may be imaged as a composite feature when at least attempting to identify their locations.

12.2 Vertical Seismic Profiling

Although a VSP survey can be conducted in less time and for less cost than a surface seismic survey, there are still significant challenges with using it for CO_2 plume tracking. As with surface seismic, the source used will have a range between approximately 10 Hz to about 200 Hz. Again, this means the best possible resolution will be approximately 25 ft for reflection imaging and 100 ft for tomography. In other words, it is unlikely to detect a CO_2-bearing zone that is thinner than this. In VSP, because the receivers are located downhole (in the well) instead of on the land surface as is the case with surface seismic, the path length that the energy waves need to travel to reach the receivers is shorter than for surface seismic. Therefore, it is more likely that the higher frequency energy waves will reach the receivers, which increases the likelihood that the best case (maximum) resolution can be achieved.

VSP is being considered as a geologic characterization technique. By conducting a VSP prior to shooting a 3D survey, the 3D can be optimized based upon the results of the VSP.

12.3 Crosswell Seismic

Of the three seismic techniques evaluated, crosswell seismic offers the highest resolution. The crosswell source is capable of emitting energy between 100 and 1200 Hz. This allows for potential resolution to increase significantly. Depending on the well spacing and the quality of data, geologic features approximately 10 ft in thickness may be detectable. This is consistent with what has been seen in the crosswell seismic surveys conducted for the pilot-scale project, which suggest that it may be possible to resolve the thin (~ 10 ft) vuggy layers in the Copper Ridge.

Although the vuggy layers may be detectable, it appears at the pilot-scale project, that changes within the intervals are not detectable. Bulk velocity change analysis, the most direct way to image changes in the formation due to injected CO_2, was not able to detect anything. This is most likely a combination of the low CO_2 saturation as well as the small layer thickness. Further data analysis may yield changes in additional parameters, such as acoustic impedance, reflectivity, amplitude, phase, or dominant frequency, due to CO_2. This work is ongoing and the parameters may change due to injection operations. However, it is unknown whether these methods will provide useful information.

Although crosswell seismic may be able to detect changes due to CO_2, it is not recommended for plume tracking for the CSP due to implementability constraints. Specifically, based on experience at the pilot-scale project, it was observed that a well spacing of approximately 500 ft is needed. The prospect of installing deep monitoring wells through the injection zones on a 500-ft spacing is unrealistic.

13.0 Wireline Logging for Plume Tracking

This section describes the proposed cased-hole wireline logging program for CO_2 plume tracking.

13.1 Purpose and Objectives

Pulsed neutron capture (PNC) logging will be the primary logging technique used for CO_2 plume tracking. The primary objective for running PNC logs is to detect and delineate the injected CO_2 within the injection reservoir(s). However, PNC logging also provides a method to detect vertical migration of the injected CO_2 out of the injection reservoir(s) into overlying zones in the immediate vicinity of logged wells.

13.2 Description

Using PNC logs for CO_2 plume tracking requires one or more baseline logging runs and subsequent repeat logging runs over time once CO_2 injection has started. PNC logs collected after injection has started will be compared to the baseline PNC log(s) to determine if there has been a change in the measured bulk sigma values for the injection zone. Natural, baseline sigma values in the Rose Run and Copper Ridge vary from approximately 10-20 capture units (CU) at the PVF wells. The PNC tool is accurate to within +/- 0.5 CU. CO_2 displacement of native pore fluids (brine) is expected to cause a significant reduction in the background bulk sigma values as was observed in several of the wells at the PVF site (e.g. AEP-2 and MW-3). Figure 13-1 gives a selected depth interval from MW-3 which shows an overlay of the baseline and repeat logging runs. The shaded area between the baseline and repeat curves indicates the presence of injected CO_2.

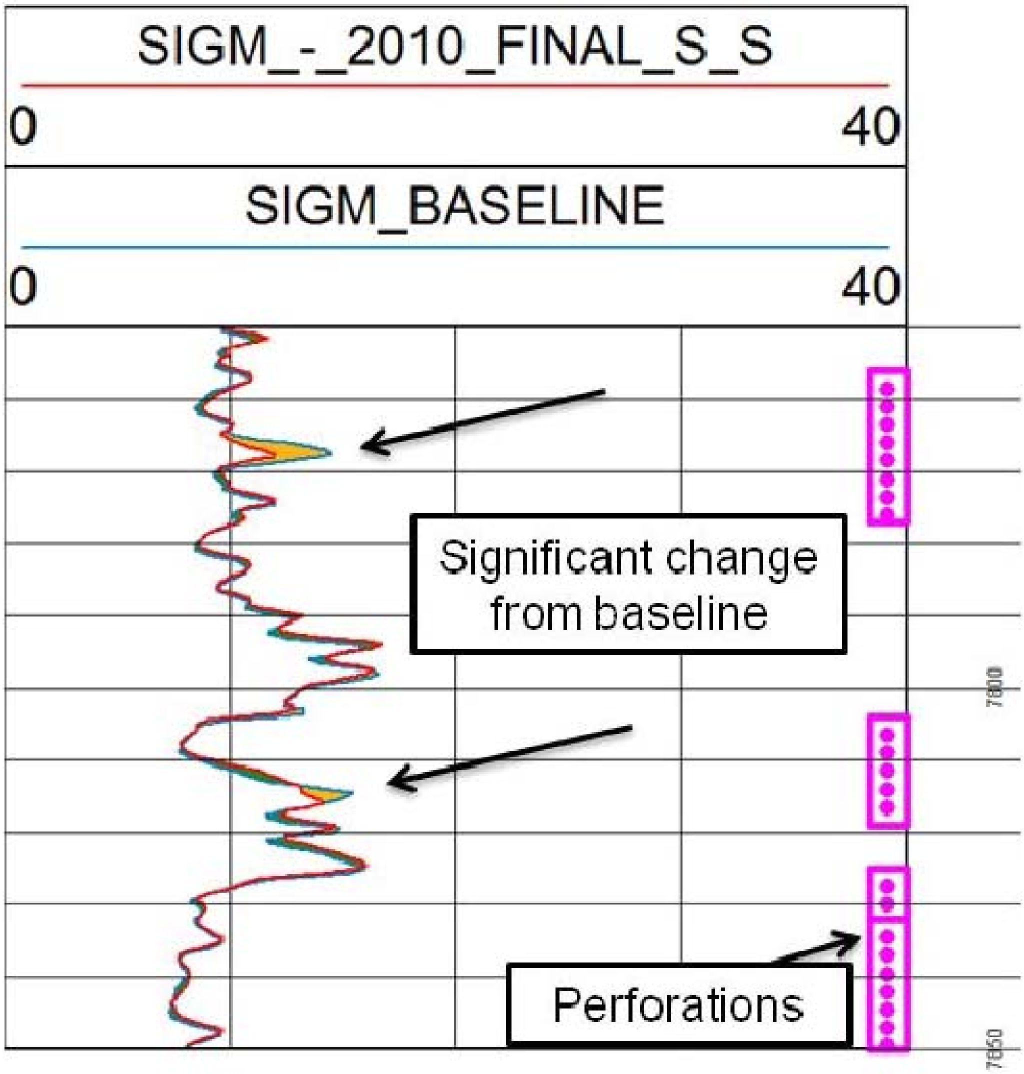


Figure 13-1. Overlay of Repeat and Baseline PNC Logs from MW-3 (Rose Run Formation) at the PVF Site. Orange Shading Between Curves Indicates Presence of CO_2.

13.3 Baseline Monitoring

Baseline logging would be conducted in all injection wells and in all deep monitoring wells, including those in the injection reservoir(s) and any wells completed in intermediate-depth zones overlying the caprock. The baseline logs would be run after the wells have been completed but before CO_2 injection begins.

The effect from drilling fluid invasion can complicate the interpretation of repeat logging runs with respect to CO_2 migration near the wellbore, as drilling fluid artificially raises the measured bulk sigma value. Therefore, logging should be conducted as long after the completion of the well as possible to eliminate any effects due to drilling fluid invasion on the baseline bulk sigma signature, as these effects seem to dissipate with time. While the effect can be partially overcome through data processing, it may also be necessary to alter the composition of the drilling fluid or conduct further borehole conditioning upon completion of the well.

It may be necessary to "kill" the well prior to logging if there is significant pressure at the wellhead (i.e. greater than what can be handled using standard pressure control equipment). Killing the well involves pumping a kill fluid (e.g., brine) into the well, which will have the undesirable effect of introducing kill fluid into the formation adjacent to the well's perforations (i.e., the injection zone) and potentially displacing any CO_2 present in this zone. Consequently, killing the well will diminish the usefulness of the PNC log for the injection zone(s). However, the data may still be useful for assessing upward migration of CO_2 out of the injection zone adjacent to the borehole. Killing isn't likely to be necessary for monitoring wells if they are located a sufficient distance away from the injection wells.

PNC logging runs will be conducted across the perforated interval(s), across the injection target(s), and across a pre-determined section of the confining layer(s).

Processing of the PNC data would be conducted by the vendor chosen to run the logs. Typical processing time for these data is roughly two months while the interpretation may add an additional month to the turnaround time. Discussions between Battelle and the vendor will take place prior to logging, after the completion of logging, and after the completion of data processing to ensure data quality and address any outstanding interpretation issues.

13.4 Operational Phase Monitoring

After CO_2 injection operations begin, repeat PNC logging will be conducted regularly in the injection and monitoring wells that are completed in the injection reservoir(s) and all intermediate-depth monitoring wells. Repeat logging in the injection well(s) will be conducted at regularly scheduled intervals, for example annually, unless logging of the well(s) cannot be accomplished without introducing kill fluid into the reservoir(s). In this case, PNC logging of the injection wells would be conducted at the end of the 5-year injection period. The frequency of repeat logging in the monitoring wells will depend on the location of the well relative to the injection well(s) and the estimated CO_2 front. For example, logging might be conducted annually in distant monitoring wells at first and monthly, quarterly or semi-annually in any monitoring wells located close to the injection well(s). As the CO_2 plume expands beyond the proximal monitoring well, the frequency of logging in this well could be decreased while the frequency of logging in the distal wells might need to be increased if CO_2 breakthrough is anticipated. Additionally, opportunistic logging runs may be possible during the operational phase which could be substituted in place of a planned logging run.

Repeat PNC logs should be run under identical conditions as the baseline logging run. For this reason, all baseline logs and repeat logs should be run through tubing, to avoid having to correct repeat logs for the presence of tubing.

14.0 Monitoring Fluid Chemistry in the Injection Reservoirs

14.1 Purpose and Objectives

The purpose of performing fluid (brine) sampling in deep wells completed in the injection reservoirs is to aid in assessing the lateral extent of injected CO_2 over time and to characterize geochemical changes caused by interaction between the injected CO_2 and the host formations. This will be accomplished by collecting samples before, during, and after CO_2 injection and analyzing samples for chemical parameters that are indicators of the presence of CO_2.

14.2 Description

Annually, fluid samples will be collected from the deep monitoring wells that are completed in the Copper Ridge injection reservoir. All brine samples will be analyzed for parameters that are indicators of CO_2 dissolution (Table 14-1). These parameters include selected anions, cations, general water quality parameters (pH, alkalinity, total dissolved solids, specific gravity), and stable isotopes of carbon, oxygen, and hydrogen.

Table 14-1. Analytical Parameters for Monitoring Fluid Chemistry of the Injection Reservoirs

Cations	Anions	Physical Parameters	Other
Potassium Sodium Calcium Magnesium Iron Manganese Aluminum Barium Boron Lithium[(b)] Strontium Dissolved Silica	Chloride Sulfate Bromide Fluoride	pH[(a)] Alkalinity (Bicarbonate) Alkalinity (Carbonate) Total Dissolved Solids Specific gravity/ Density Specific conductance[(a)] Temperature[(a)] Turbidity[(a)]	Stable hydrogen isotopes (D/H) Stable oxygen isotopes (^{18}O /^{16}O) Stable carbon isotopes (^{13}C/^{12}C) Dissolved CO_2 Tracers

(a) Field parameter
(b) Analysis for CO_2 will be performed only if a sample is collected with a downhole sampling device that preserves the sample at ambient pressure. Swabbing will not provide representative results for dissolved gases.

14.3 Baseline Monitoring

Baseline monitoring is necessary to characterize the background fluid chemistry of the injection reservoirs. Baseline monitoring will involve collection and analysis of at least one round of groundwater samples from each well before CO_2 injection begins. If time allows, additional samples should be collected.

14.4 Operational Phase Monitoring

During active injection of CO_2, all deep monitoring wells completed in the injection reservoir will be sampled on a regular basis (e.g., semi-annually) for evidence of CO_2 breakthrough. Injection wells will not be sampled during the operational phase because this would require interrupting injection, but will be sampled at the conclusion of the injection period. Fluid samples will be analyzed for the same parameters that are assessed in the baseline monitoring event (Table 14-1).

Sampling frequency may be modified as the CO_2 plume expands. For example, relatively infrequent monitoring (e.g., semi-annual) may be appropriate for a well that is located far beyond the CO_2 front or well within the CO_2 plume, but more frequent monitoring (e.g., monthly) may be required when the CO_2 front is first approaching a well in order to accurate assess CO_2 breakthrough as this information is needed to help calibrate the reservoir model.

15.0 Monitoring Pressure in the Injection Reservoirs

This section describes the proposed injection reservoir pressure monitoring program.

15.1 Purpose and Objectives

The primary objective for monitoring reservoir pressure is to provide data for calibrating the reservoir model (see Section 16) that will be used to help track CO_2 and pressure in the injection reservoirs. Additional benefits of monitoring reservoir pressure include:

- monitor the pressure buildup in the injection zone(s) that will occur as a result of injection and guard against over pressuring which could induce unwanted fracturing of the reservoir or the overlying caprock;

- evaluate the need for injection well rehabilitation; and,

- provide data for assessing reservoir properties (e.g., permeability, porosity, reservoir size).

15.2 Description

Continuous monitoring of reservoir pressure is done with pressure sensors installed in the wells to the depth of the injection reservoir. The pressure sensor includes a temperature sensor; therefore, temperature data will be collected concurrent with pressure data. Pressure monitoring will likely be done differently in the injection wells and the monitoring wells. Pressure monitoring in the injection wells will be done using real-time sensors with surface readout instrumentation. These instruments do not have to be removed from the well to retrieve the data because they are connected to a surface controller with display capabilities via a down-hole cable. Pressure monitoring in monitoring wells will likely be done using data logging gauges (memory gauges) that have to be periodically removed from the well to retrieve the data. However, if the monitoring wells need to be designed to monitor multiple zones, a more sophisticated well completion design will be needed to achieve continuous pressure monitoring (e.g., multiple packers suspended on tubing to isolate the individual injection zones and permanent pressure sensors with communication cable to surface and real-time surface readout capability).

The proposed monitoring well spacing (shown in Figure 2-1) has been designed to detect the pressure response from the injection wells over the lifetime of the injection period. Figure 15-1 shows the predicted pressure response over time at various distances from the Copper Ridge injection well, corresponding to the approximate distances of the proposed Copper Ridge monitoring wells. The short-term spikes in pressure correspond to annual maintenance events (each lasting 2 months) when one of the two Copper Ridge injection wells is shut down and 100% of the CO_2 is injected into the other well. Assuming a pressure change of $\geq$10 psi can be reliably measured by the pressure gauges, this plot shows that the monitoring wells are located properly to be able to detect the injection pressure signal within a period ranging from about one day (nearest well) to approximately 90 days (farthest well). Note that the nearest monitoring well (distance = 2,500 ft) exhibits a somewhat different response than the more distant monitoring wells because this well is located within the CO_2 plume. CO_2 breakthrough occurs at this well at approximately 100 days. Prior to breakthrough, the pressure response is dominated by the properties of brine, whereas after breakthrough, the pressure response is dominated by the properties of CO_2.

15.3 Baseline Monitoring

Baseline monitoring will entail the installation and testing of the pressure sensors in the injection wells and monitoring wells and collection of pressure data for a period of time (e.g., at least one month) prior to the start of injection. Thus, baseline reservoir pressure monitoring cannot be initiated until the wells have been installed.

15.4 Operational Phase Monitoring

During the active injection phase, continuous monitoring of downhole pressure and temperature will be continued in the deep monitoring wells and the CO_2 injection wells. The pressure gauges will be removed from the monitoring wells when necessitated by battery life and data storage capacity of the gauges (e.g., quarterly) or more frequently of necessitated by other activities (e.g., well maintenance).

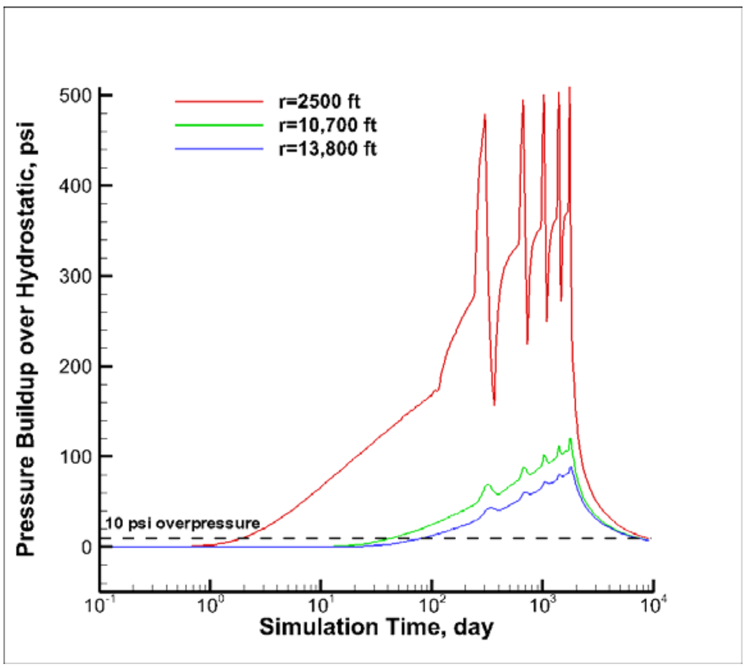


Figure 15-1. Predicted Pressure Response at Monitoring Wells in the Copper Ridge Injection Reservoir.

16.0 Modeling

This section describes the plan to develop and implement a 3-D numerical reservoir model to help track and predict the migration of the CO_2 plume and pressure disturbances in the injection reservoir(s).

16.1 Purpose and Objectives

The numerical reservoir model (also referred to as the *dynamic* model) is intended to be a representation of the subsurface geologic environment with the capability to compute CO_2 migration dynamics and pressure perturbations in the subsurface. The numerical model serves as a framework for integrating all pertinent field data – including both pre-injection geologic and geophysical investigations as well as injection rate and pressure data from the active injection period. The results of the modeling studies will provide baseline predictions of CO_2 and pressure migration in the injection reservoir(s) prior to injection. Subsequently, injection data from the active injection phase will be used to calibrate the model and update predictions of plume migration and Area of Review (AoR) calculations.

16.2 Description

The starting point for the numerical reservoir model is a geologic framework model (also referred to as the *static* model) which provides a 3-D representation of the subsurface based on information from regional geologic and geophysical studies as well as site characterization wells specific to the project. The current static model, based on data from the five PVF wells, will be updated during Phase I (Preliminary Design) and II (Detailed Design) using site characterization data collected from the two or three characterization wells (including logging, coring and reservoir testing data) that are installed and tested during these phases and a baseline seismic survey. During Phase III (construction phase), the 3D static model will be updated again (i.e., revise the geologic framework) with additional geology data obtained from the installation of the injection and monitoring wells at each injection site.

Once all relevant geology and geophysics data are integrated into the 3-D static model, the following information required for building an initial 3-D reservoir model can be extracted:

- Large-scale structural features (e.g., formational contacts)
- Description of facies / flow units
- 3-D porosity maps (per facies)
- 3-D permeability maps (per facies)
- Description of flow barriers (faults etc.)
- Alternative (geostatistical) realizations of geology conditioned to well data

Depending on the amount of information available, the static model could be a suite of models including a reference case, as well as additional scenarios that attempt to capture the uncertainty in understanding the subsurface because of data sparsity. These discrete alternative conceptual models of the geologic framework could then be used for quantifying uncertainty in dynamic model predictions.

In the next step, the static model grid will be converted into a grid for dynamic modeling – while balancing the competing goals of detailed numerical resolution (and accuracy) versus computational efficiency. This may require an upscaling of reservoir properties to account for any disparity in resolution between the static and dynamic modeling grids. Fluid properties needed for dynamic modeling (e.g., PVT properties, relative permeability characteristics, etc.) are also input into the dynamic model at this stage.

While reservoir properties in static model will be based on small-scale (on the order of centimeters) core- and log-data, the dynamic model grid will likely be much larger (on the order of 10 meters) because of computational considerations. As such, the reservoir property fields generated during the static model will need to be upscaled to provide appropriate inputs for the dynamic model. This requires appropriate spatial averaging algorithms be applied to the underlying data (e.g., arithmetic averaging for porosity, resistance-based averaging for permeability).

16.3 Baseline Monitoring

Once the dynamic model is developed, it will be used in a prediction mode (prior to the commencement of injection activities) to provide valuable information regarding future CO_2 injection performance, viz.:

- Total mass injected,
- Free versus dissolved CO_2,
- CO_2 leakage into caprock,
- Regional brine displacement,
- Spatial extent of CO_2 plume, and
- Spatial extent of pressure propagation.

These results will provide a quantitative description of CO_2 plume evolution during the injection and post-injection phase, which would serve as baseline monitoring conditions. 2-D horizontal plume maps will be useful for showing the annual expansion in the injection reservoir/formation. 2-D vertical plume maps will also be useful for understanding how the plume is spreading within each injection reservoir. Additional value of such results is in understanding the areal extent of the pressure "bubble" over time, and the fate of brine displaced by injected CO_2.

The model will also be used to evaluate sensitivity of model response to uncertain assumptions (e.g., relative permeability curves, anisotropy in permeability) in addition to the set of alternative conceptualization of the geologic framework. These additional model runs will be helpful in developing an understanding of the likely range of model predictions from the reference case, as well as the most important input affecting prediction uncertainty.

16.4 Operational Phase Monitoring

In Phase IV (active injection phase) the model will be calibrated initially, and then annually, using the reservoir pressure data and other monitoring results (e.g., seismic, PNC logging, fluid chemistry) that are obtained.

Analysis of pressure data from injection testing can provide additional information regarding large-scale permeability values which can be used to adjust preliminary permeability maps derived from the static model. History matching involves adjustment of this permeability map such that the large-scale average is consistent with the interpretation of transient pressure data, the model predicted pressure history is consistent with observations of pressures observed at the injection and monitoring wells. At this stage, modifications may also be needed in the static-model derived porosity fields as well as assumed relative permeability characteristics.

This iterative approach to refining the model based on observations of pressure and other monitoring results will result in more robust forecasts of CO_2 plume and pressure disturbance migration within the reservoir and also allow the monitoring plan to be modified (as needed) to optimize the worth of collecting additional data. The annual calibration process would also help constrain the model parameters, thus reducing the uncertainty in future model predictions.

17.0 USEPA Mandatory Reporting Requirements for Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide

This section describes the proposed subsurface monitoring and reporting to meet USEPA Mandatory Reporting Requirements for Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide.

17.1 Purpose and Objectives

The objective of this monitoring task would be to fulfill USEPA Mandatory Reporting Requirements for Greenhouse Gases from Injection and Geologic Sequestration of Carbon Dioxide. The task would focus on monitoring CO_2 leakage from the reservoir with a network of soil gas monitoring probes in the areas overlying the CO_2 plumes. Monitoring of the CO_2 injection volume and rate would be addressed in operational monitoring along the pipeline and wellhead.

17.2 Description

The USEPA rule for Mandatory Reporting of Greenhouse Gases from Injection and Geologic Sequestration of Carbon Dioxide is listed in the Federal Register (40 CFR Part 98) and was finalized December 1, 2010. In general, the rule requires monitoring the amount of CO_2 injected versus the amount of CO_2 that leaks back to the atmosphere. The subsurface requirements include:

- Develop a Monitoring, Reporting, and Verification (MRV) plan that describes the methodology for, rational for, and frequency of evaluation of the entire spatial area of the GS facility to detect any CO_2 emissions from unexpected pathways. The MRV plan would describe the monitoring technologies that will be employed at the facility, the assumed detection limits of the technologies, the monitoring locations, spatial array, and frequency of sampling. The monitoring plan would also include a survey of the area of review (as determined by reservoir simulations) for leakage pathways (i.e., leakage risk assessment). The MRV plan would be due to EPA six months after the area of review was finalized (accepted) in the UIC permit process (i.e., 6 months after UIC permit is issued).

- Implement a monitoring program focused on detection and quantification of CO_2 emissions throughout the lifetime of the injection period. The monitoring program would also need to establish pre-injection baseline conditions before the start of CO_2 injection.

- Report annually the results of the monitoring program throughout the operational period.

For the sake of this preliminary monitoring plan, it was assumed that a soil gas monitoring program will be designed and implemented to fulfill EPA monitoring requirements.

17.3 Baseline Monitoring

A number of soil-gas monitoring probe clusters would be installed in the area above the anticipated CO_2 plume. Each cluster would include two or three soil-gas monitoring probes, each installed at a different depth within the vadose zone. At minimum, a cluster of soil-gas probes would be installed adjacent to each USDW monitoring well location to provide co-located groundwater and soil-gas monitoring data. Soil gas samples would be analyzed for indicators of CO_2 leakage, including for example O_2, CO_2, N_2, CH_4, $\delta^{13}C$-CO_2, ^{14}C-CO_2 and introduced tracers (if applicable) such as perfluorocarbon compounds. Detection of leakage would rely on results of other leak-detection monitoring methods that will be implemented to comply with the UIC requirements, including USDW aquifer monitoring, PNC logging, and intermediate-depth leakage monitoring. If necessary, other near surface monitoring technologies (e.g. surface flux monitoring) may be implemented in addition to augment this surface emissions monitoring program. Baseline monitoring would include installing the soil-gas monitoring probes and conducting sampling on a monthly or quarterly basis for one to two years prior to starting CO_2 injection.

17.4 Operational Phase Monitoring

After CO_2 injection begins, soil gas sampling and analysis will be conducted on a quarterly basis in conjunction with USDW aquifer groundwater monitoring. Annual monitoring reports would be generated for submittal to the U.S. EPA. These reports would not fulfill EPA greenhouse gas monitoring requirements such as fugitive emissions along CO_2 transfer points, quantity of CO_2 lost during pipeline transport, and quantity of CO_2 injected, which would be reported elsewhere.

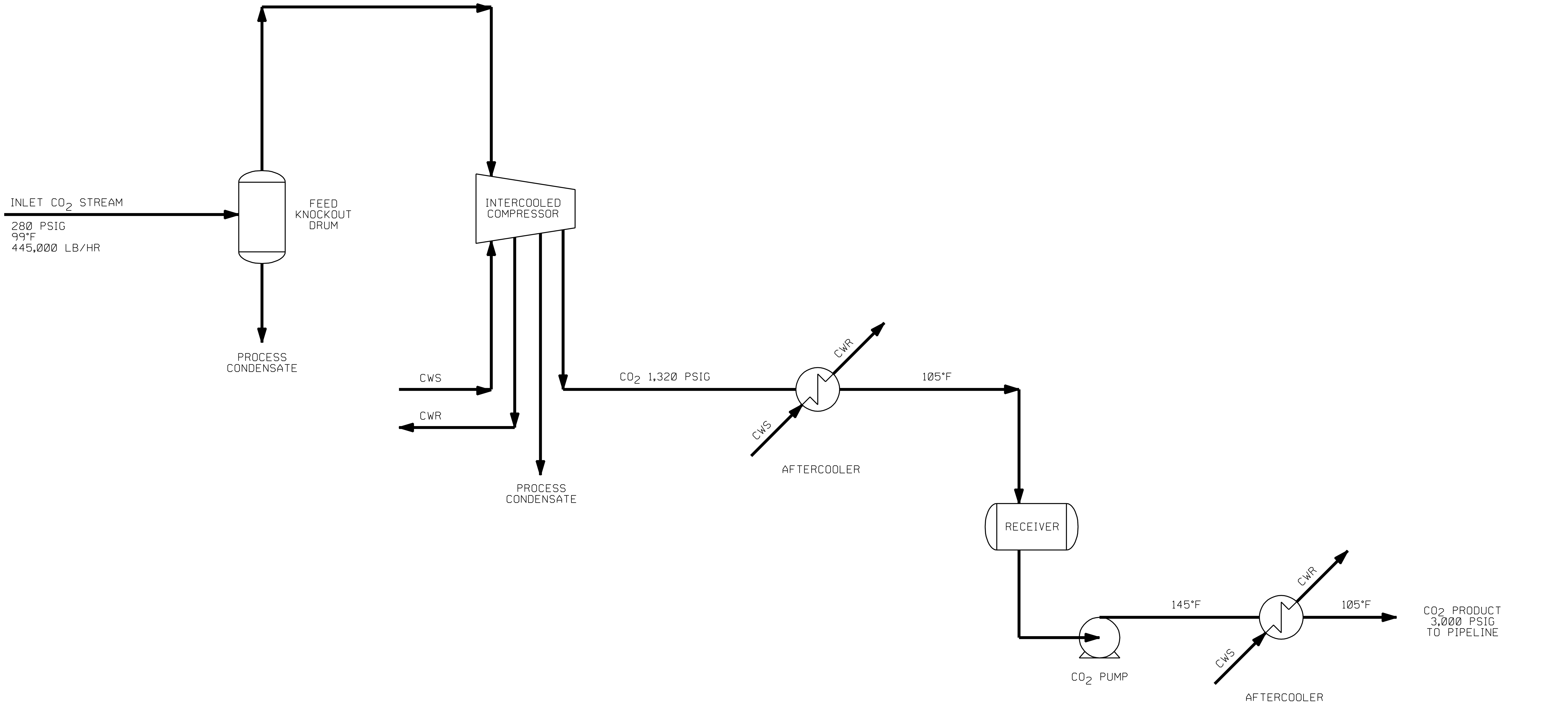
18.0 References

United States Code of Federal Regulations, Title 40, Part 146, Section 146.8.

U.S. Environmental Protection Agency, 2002. UIC Perssure Falloff Testing Guidelines, Third Revision. U.S. EPA Region 6, August 8, 2002.

Appendix C - List of Drawings

Drawing Number	Description
FS-1.01.01.01.03-001	Process Flow Diagram, Intercooled Compressor with Pump Alternative 1
FS-1.01.01.01.03-003	Process Flow Diagram, Intercooled Compressor with Refrigeration Alternative 3
FS-1.01.01.01.03-004	Process Flow Diagram, Intercooled Compressor Alternative 4
AEPMT-1-DW-111-002-003	CO_2 Pipeline Routing Overall Plot Plan



NOTE:

CWS: COOLING WATER SUPPLY
CWR: COOLING WATER RETURN

AEP MOUNTAINEER CCS II
PROCESS FLOW DIAGRAM
INTERCOOLED COMPRESSOR WITH PUMP
ALTERNATE 1

SCALE	DRAWING NUMBER
NONE	FS-1.01.01.01.03-001

ARCH D (36" x 24")

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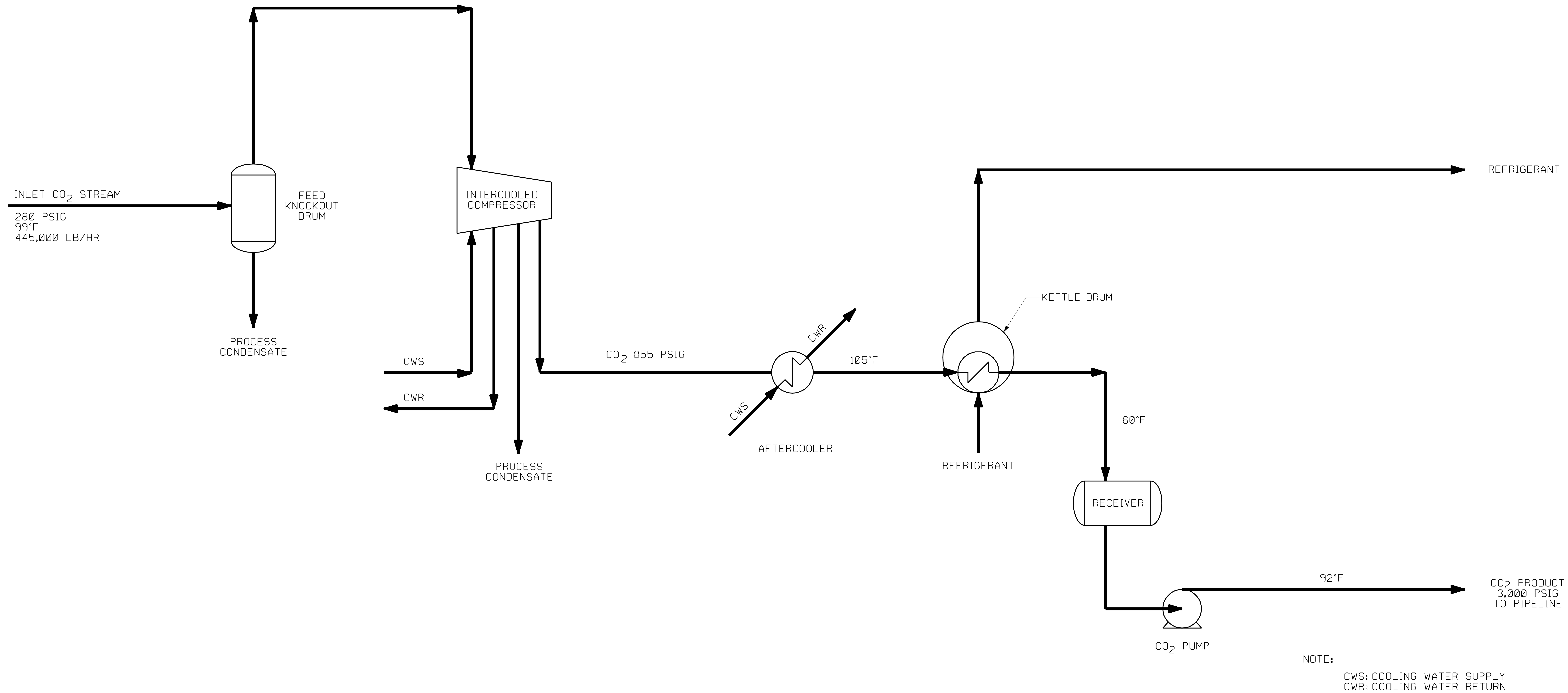

AEP MOUNTAINEER CCS II
PROCESS FLOW DIAGRAM
INTERCOOLED COMPRESSOR
WITH REFRIGERATION ALTERNATE 3

SCALE NONE	DRAWING NUMBER FS-1.01.01.01.03-003

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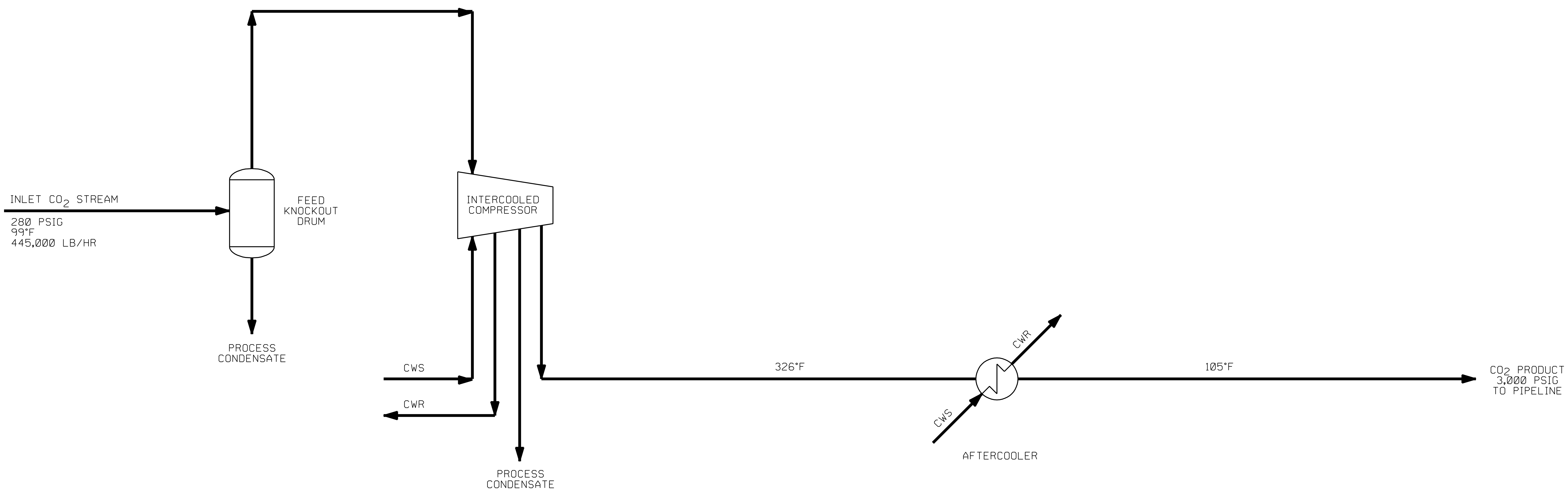

NOTE:

CWS: COOLING WATER SUPPLY
CWR: COOLING WATER RETURN

AEP MOUNTAINEER CCS II
PROCESS FLOW DIAGRAM
INTERCOOLED COMPRESSOR
ALTERNATE 4

SCALE	DRAWING NUMBER
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ARCH D (36" x 24")

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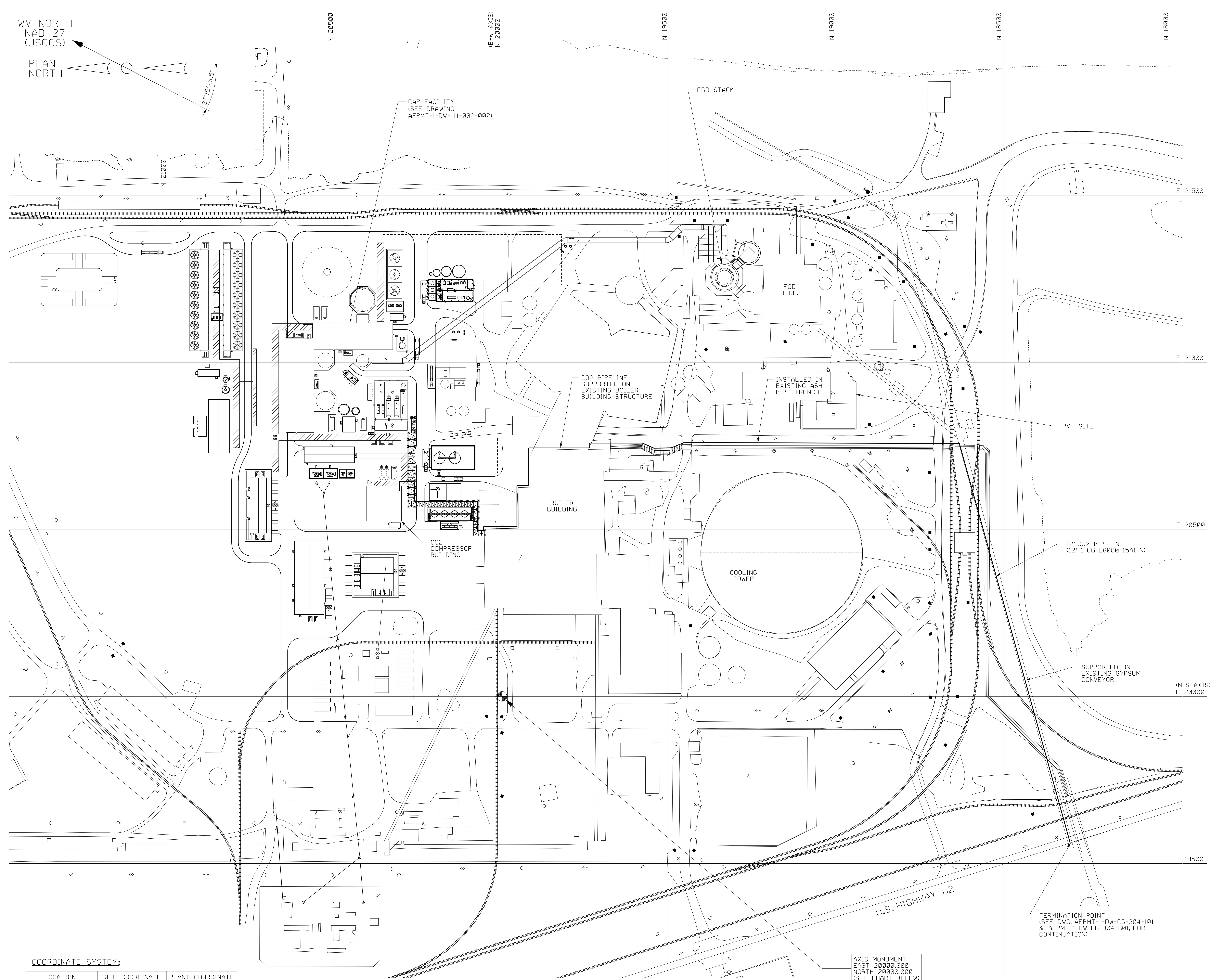

COORDINATE SYSTEM:

LOCATION	SITE COORDINATE	PLANT COORDINATE
AXIS MONUMENT EAST/ WEST	E 1733019.230	E 20000.000
AXIS MONUMENT NORTH/ SOUTH	N 721963.120	N 20000.000
AXIS MONUMENT	ELEV. 588.182	ELEV. 102.182
GRADE ELEVATION	ELEV. 586'-0"	ELEV. 100'-0"

(SITE COORDINATES LISTED ABOVE ARE BASED ON WEST VIRGINIA STATE PLANE GRID NAD27, NGVD29)

REFERENCE DRAWINGS:

AEPMT-1-DW-111-002-002 CAP FACILITY PLOT PLAN

REV	DATE	DESCRIPTION	DRAWN	CHECKED	LEAD DESIGNER	ENGINEER/ TECH. SPEC.	LEAD DISC ENGINEER	PROJ ENGR MANAGER	PROJECT MANAGER
A	06 07 11	ISSUED FOR INFORMATION ONLY	RWB		RWB	SGW	SGW	JFW	RJM

PRELIMINARY STATUS DATE — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
LDE SG WAINWRIGHT 06-07-11

APPROVED STATUS DATE — REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
LDE

ORIGINATING PERSONNEL

DRAWN BY: RWB
CHECKED BY:
LEAD DESIGNER: RW BREISCH
ENGINEER/TECH SPECIALIST: SG WAINWRIGHT
PROJECT ENGINEERING MANAGER: JF WAGNER
PROJECT MANAGER: RJ MARTIN

Zero Harm — Leadership, No Incidents, Safe Behavior

PROFESSIONAL ENGINEER'S SEAL

ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF
PE:_____________ STATE:_______
LIC. NO.:___________ DATE:________

WorleyParsons
resources & energy

CLIENT/PROJECT TITLE
APPALACHIAN POWER COMPANY
MOUNTAINEER PLANT

CO2 PIPELINE ROUTING
OVERALL PLOT PLAN

SCALE 1"=100' | DRAWING SIZE ANSI E (44" x 34")

WORLEYPARSONS DWG. NO. AEPMT-1-DW-111-002-003 | REV A

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