THE OHIO RIVER VALLEY CO_2 STORAGE PROJECT
AEP MOUNTAINEER PLANT, WEST VIRGINIA
FINAL TECHNICAL REPORT

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Prepared for
U.S. Department of Energy-
National Energy Technology Laboratory
Project Managers: Lynn Brickett and Charles Byrer

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ABSTRACT

This report includes an evaluation of deep rock formations with the objective of providing practical maps, data, and some of the issues considered for carbon dioxide (CO_2) storage projects in the Ohio River Valley. Injection and storage of CO_2 into deep rock formations represents a feasible option for reducing greenhouse gas emissions from coal-burning power plants concentrated along the Ohio River Valley area. This study is sponsored by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), American Electric Power (AEP), BP, Ohio Coal Development Office, Schlumberger, and Battelle along with its Pacific Northwest Division.

An extensive program of drilling, sampling, and testing of a deep well combined with a seismic survey was used to characterize the local and regional geologic features at AEP's 1300-megawatt (MW) Mountaineer Power Plant. Site characterization information has been used as part of a systematic design feasibility assessment for a first-of-a-kind 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 have been used for reservoir simulations and to support the review of the issues relating to injection, monitoring, strategy, risk assessment, and regulatory permitting. The high-sulfur coal samples from the region have been tested in a capture test facility to evaluate and optimize basic design for a small-scale capture system and eventually to prepare a detailed design for a capture, local transport, and injection facility.

The Ohio River Valley CO_2 Storage Project was conducted in phases with the ultimate objectives of demonstrating both the technical aspects of CO_2 storage and the testing, logistical, regulatory, and outreach issues related to conducting such a project at a large point source under realistic constraints. The site characterization phase was completed, laying the groundwork for moving the project towards a potential injection phase. Feasibility and design assessment activities included an assessment of the CO_2 source options (a slip-stream capture system or transported CO_2); development of the injection and monitoring system design; preparation of regulatory permits; and continued stakeholder outreach.

ACKNOWLEDGEMENTS

This report includes an assessment of the deep saline reservoirs, caprock formations, and coal seams in the Ohio River Valley with the objective of evaluating geologic formations and their storage parameters, as well as evaluating design and monitoring considerations for implementing CO_2 storage. This report fulfills the requirements of U.S. Department of Energy National Energy Technology Laboratory Project # DE-AC26-98FT40418 (Project Managers – Lynn Brickett and Charles Byrer). The overall project is also supported by American Electric Power (Project Managers – Gary Spitznogle and Mike Mudd); the Ohio Coal Development Office of the Ohio Air Quality Development Authority (Project Manager – Robert Brown and Howard Johnson), BP (Project Manger – Charles Christopher); Schlumberger (Scientific advisor - T.S. Ramakrishnan), Battelle, and its Pacific Northwest Division. A number of other organizations have provided technical and in-kind support. In addition to the project managers in the sponsor organizations, the performers wish to acknowledge the encouragement and stewardship provided by Dale Heydlauff and Manoj Guha at AEP, Scott Klara at DOE/NETL, Jackie Bird formerly with the Ohio Coal Development Office, Gardiner Hill at BP, and Donald McConnell and Henry Cialone at Battelle. This effort has benefited from technical contributions and strategic advice from a large number of people in the project sponsor and vendor organizations, some of whom are mentioned below:

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- Independent energy producers Bakerwell, Inc. and Murphy Oil Company participated in regional characterization efforts.

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ACRONYMS AND ABBREVIATIONS

acfm	actual cubic feet per minute
AEP	American Electric Power
ASU	air separation unit
bgs	below ground surface
CLC	chemical looping combustion
CMR	combinable magnetic resonance
CO_2	carbon dioxide
DOE	(United States) Department of Energy
DSI	dipolesonic imager
EOR	enhanced oil recovery
FGD	flue gas desulfurization
ktonne	thousand metric tonnes
IGCC	integrated gasification combined cycle
LSFO	limestone forced oxidation
MEL	magnesium enhanced lime
mD	milliDarcy
MMscfm	million standard cubic feet per minute
MW	megawatt
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
OCDO	Ohio Coal Development Office
ODNR	Ohio Department of Natural Resources
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
RST	reservoir saturation tool
SCADA	supervisory control and data acquisition
scfm	standard cubic feet per minute
UIC	Underground Injection Control
U.S. EPA	United States Environmental Protection Agency
USGS	United States Geological Survey

EXECUTIVE SUMMARY

Introduction

The objective of this report is to assess the potential for geologic storage of CO_2 in the Ohio River Valley. This report includes an evaluation of deep rock formations with the purpose of providing practical maps, data, and some issues to consider for CO_2 storage projects in the region. Much of the information was based on a 2,800 m deep test well that was completed for the project. Injection and storage of CO_2 into deep rock formations represents a feasible option to reduce greenhouse gas emissions from coal-burning power plants concentrated along the Ohio River Valley area. This study is sponsored by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), American Electric Power (AEP), BP, Ohio Coal Development Office, Schlumberger, and Battelle along with its Pacific Northwest Division.

An extensive program of drilling, sampling, and testing a deep well combined with a seismic survey was used to characterize the local and regional geologic features at AEP's 1300-megawatt (MW) Mountaineer Power Plant outside of New Haven, West Virginia. Site characterization information has been used as part of a systematic design feasibility assessment for a first-of-a-kind test-scale 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 have been used for reservoir simulations and for supporting the design of the issues relating to injection, monitoring, strategy, risk assessment, and regulatory permitting. Several CO_2 capture technologies were evaluated for a small-scale capture system with the objective of eventually preparing a detailed design for a capture, local transport, and injection facility.

CO_2 Injection, Monitoring, and Capture Issues

Site Characterization – The Mountaineer Power Plant is located in the Appalachian Basin region along the Ohio River. Geologically, this area consists of approximately 3,000 m of interlayered carbonates, shales, and sandstone layers. The site characterization phase during 2003 and 2004 included a 16-km long two-dimensional seismic survey, which showed that the geology at the site consists of essentially flat sedimentary layers with no discernible faulting in the area. The subsurface characterization was conducted through drilling, coring, wireline logging, and testing a 2,800-m deep borehole (Figure ES-1) to the top of Precambrian basement rocks. As anticipated for mature deep geologic basins and from predrilling prognosis, the test borehole showed that the area is dominated by dense dolomite, limestone, and shale layers, and much of the sandstone is relatively compact and highly cemented. The logging and testing confirmed the presence of several potential injection zones. Specifically, the Rose Run sandstone, an interbedded sandstone and dolomite layer at about a depth of 2,400-m, shows promise as an injection zone. In addition, several thin zones of very high primary or secondary permeability were observed within the Copper Ridge dolomite layers. These formations are known through much of Ohio but are poorly understood locally. The basal sandstone does not appear to be a viable sequestration target in southeastern Ohio, but is a very promising target in western Ohio where it is known as the Mt. Simon formation. The extensive dolomites and shales provide excellent containment. Two stages of reservoir testing were completed in the test well to confirm storage properties of specific zones with a series of reservoir injection, flowmeter, and mini-frac tests.

The main oil and gas plays in deeper formations in the region are present in "Clinton"-medina sandstone, Oriskany-Newburg sandstones, Devonian black shales, and the Berea sandstone. Oriskany-Newburg sandstones appear to offer the best potential for CO_2 storage in depleted oil and gas fields. Overall, it appears that there are no immediate opportunities for enhanced coal bed methane recovery in the Ohio River Valley. Development of this option would require additional investigation and infrastructure.

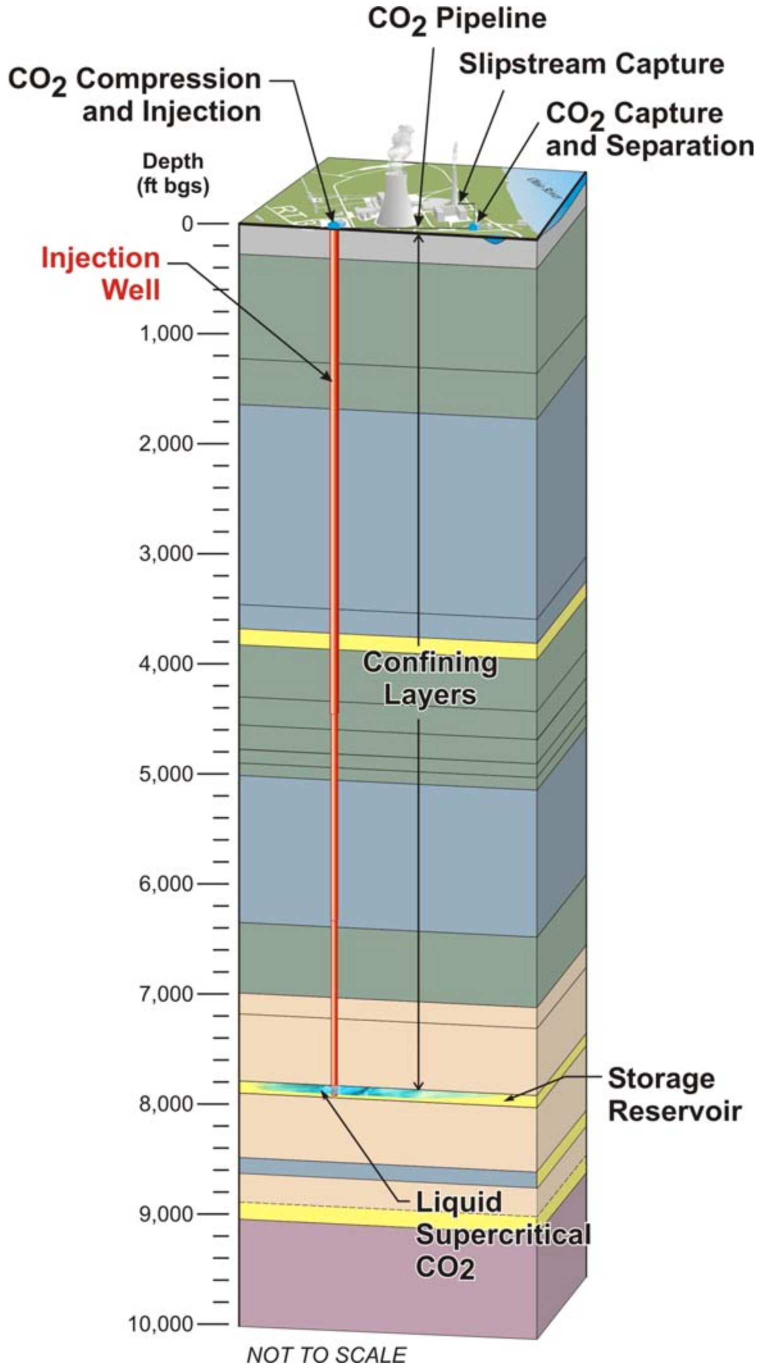


Figure ES-1. Block Diagram of the Mountaineer Site Showing Surface Features and Subsurface Geology

CO_2 Reservoir Simulations and Risk Assessment – A series of numerical simulations of CO_2 injection were conducted as part of a program to assess the potential for geologic sequestration in deep geologic reservoirs, the Rose Run formation and the Copper Ridge formation, at the AEP Mountaineer Power Plant outside of New Haven, West Virginia. The simulations were executed using the H_2O-CO_2-NaCl operational mode of the Subsurface Transport Over Multiple Phases (STOMP) simulator (White and Oostrom, 2006). Model input was based on site characterization information and hydraulic parameters from the AEP No. 1 well and calibrated to reservoir tests in the well. A series of model realizations with a range of hydraulic parameters were analyzed to explore sensitivity and uncertainty in the modeling results. In addition, several well completion options, such as lateral wells and well fields, were evaluated. Results suggest that injection rates of up to several hundred thousand metric tons of CO_2 per year may be sustained in the Rose Run and the Copper Ridge "B-zone." Distribution of CO_2 within the reservoirs differs for the different storage targets based on the nature of the permeability.

A systematic screening procedure was applied to the Mountaineer site utilizing the Features, Elements, and Processes (FEP) database for geological storage of CO_2 (Savage et al., 2004). The objective of the screening was to identify potential risk categories for the long-term geological storage of CO_2. Over 130 FEPs in seven main classes were assessed for the project based on site characterization information gathered in a geological background study, testing in a deep well drilled on site, and general site conditions. In evaluating the database, it was apparent that many of the items were not applicable to the Mountaineer site based on its geologic framework and environmental setting. Nine FEPs were identified for further consideration for the site. These FEPs generally fell into categories related to variations in subsurface geology, well completion materials, and the behavior of CO_2 in the subsurface. Initial work indicates that the significant FEPs may be accounted for by focusing the storage program on these potential issues.

An integrated numerical fate and transport model was developed to enable risk and consequence assessment at field scale. Results show that such an integrated modelling effort would be helpful for meeting the project objectives during different stages (e.g., site characterization, engineering, permitting, monitoring and closure). A reservoir-scale numerical model was extended further to develop an integrated assessment framework. The method was used to simulate sequestration of CO_2 in moderate quantities at the Mountaineer Power Plant. Results indicate that at the relatively low injection volumes planned for pilot-scale demonstration at this site, the risks involved are minor to negligible, owing to a thick, low permeability caprock and overburden zones. Such integrated modelling approaches coupled with risk and consequence assessment modelling are valuable to project implementation, permitting, monitoring and site closure.

CO_2 Source and the Capture System – Feasibility studies were completed for a small-scale system to capture the CO_2 at the plant to demonstrate an integrated capture and injection system that can also lead to incremental technical and cost improvements in the current capture technologies. A flue gas desulfurization (FGD) system was recently constructed at the plant with the allowance for a slip-stream port to take the part of the post-FGD flue gas at the capture facility which has been installed as part of the FGD construction. Preliminary design specifications for capture requirements have been prepared as a basis for working with the suppliers of the capture system to develop a more detailed design and incorporate novel improvements into the system. An additional aspect of the design feasibility is to evaluate the construction of a modular system so that it could be moved to alternate test locations in the future. The capture and injection system must also be integrated into the existing Mountaineer regulatory program. One example of how this is being managed is the routing of residual air discharge from the capture system back into the main flue gas duct work, so that any changes to the existing plant permits can be minimized.

Injection and Monitoring System – Current plans envisage use of compressed and dehydrated CO_2 transported from the source to the injection well using a small local pipeline. The injection system may include compression boosters (if needed) and injection pumps. Technical feasibility for well completion options indicate that lateral wells or injection into two formations may be possible. Geomechanical analysis and a review of the regional state of stress were completed to optimize the direction and azimuth of the deviated completion (Lucier et al., 2004). These same analyses suggest that a well stimulation program would be feasible to enhance injection potential and reduce cost for geologic settings which are typical of deep mature continental basins.

Regional oil and gas well drilling technology and expertise are available for construction of CO_2 injection wells in Ohio. However, the wells will require specialized construction specifications and materials to ensure long-term durability and containment. Drilling at existing power plant sites is feasible, but may require additional safety measures.

CO_2 injection will include an extensive monitoring effort before, during, and after injection including the possibility of drilling a monitoring well (or wells). Battelle has completed analysis to identify monitoring and verification options that could be applied to the Mountaineer project. The analysis reviewed monitoring technologies deployed at other CO_2 injection facilities (such as Weyburn, Frio test, Nagaoka site in Japan, In Salah, and Sleipner) and was expanded to consider new or emerging technologies. Surface monitoring options include three- and four-dimensional seismic surveys, soil gas surveys, gravity methods, passive seismic and tiltmeters. Downhole technologies include cross-well tomography along with collection of pressure, temperature, and hydrochemical data, and periodic wireline logging. Baseline monitoring requirements such as soil gas and background seismic monitoring will be deployed. With the recognition that every monitoring option may not work in all field situations, rigorous screening is being used to ensure that the final monitoring options are suitable for the site-specific conditions.

Regulatory and Outreach Issues – There are multiple regulatory issues to be addressed for injection tests. The Underground Injection Control (UIC) permit process is the primary permit needed for injection tests and full-scale deployment in the Ohio River Valley area. The program is administered through state agencies or regional United States Environmental Protection Agency (U.S. EPA) offices. For the Mountaineer site, a permit application would be submitted to the State of West Virginia Department of Environmental Protection upon concurrence of the project sponsors. At this time, it is anticipated that a UIC Class V experimental well permit will be required. For projects receiving Federal funds, such as Mountaineer, documentation must also be prepared to meet federal requirements for the National Environmental Policy Act (NEPA). Planning phases must also consider outreach activities to inform the public and other stakeholders about key project issues. As the decisions about future phases are taken, local, regional, national stakeholders, media organizations, and the technical community would be updated. An additional area for consideration for full-scale deployment and possibly for smaller tests would be to address property and mineral lease issues.

Conclusions

The Ohio River Valley CO_2 Storage Project was conducted in phases with the ultimate objectives of demonstrating both the technical aspects of CO_2 storage and the testing, logistical, regulatory, and outreach issues related to conducting such a project at a large point source under realistic constraints. The site characterization phase was completed, laying the groundwork for the potential injection phase. Feasibility and design assessment activities included an assessment of the CO_2 source options (a slip-stream capture system or transported CO_2); development of the injection and monitoring system design; preparation of regulatory permits; and continued stakeholder outreach.

Section 1.0: INTRODUCTION

This final technical report summarizes results of the Ohio River Valley Carbon Dioxide (CO_2) Storage Project. Overall accomplishments and key findings on the potential for geologic storage of CO_2 are presented. Several topical reports on the project, which provide more detail on the methods and results of the project, are available:

- *Interim Topical Report: The Ohio River Valley CO_2 Storage Project Preliminary Assessment of Deep Saline Reservoirs and Coal Seams*
- *Interim Topical Report: The Ohio River Valley CO_2 Storage Project Field Work Plan for Drilling a Test Well to Evaluate CO_2 Sequestration Potential*
- *Topical Report: The Ohio River Valley CO_2 Storage Project AEP Mountaineer Plant, West Virginia, Characterization of Potential for Geologic Storage of CO_2*
- *Final Topical Report: The Ohio River Valley CO_2 Storage Project - Numerical Simulation and Risk Assessment Report*
- *Final Topical Report: The Ohio River Valley CO_2 Storage Project- Analysis of Amine Solvent Options for CO_2 Capture and Transportation at AEP's Mountaineer Power Plant*

Sequestration of CO_2 from power plants is being considered to reduce emissions of greenhouse gases. The process includes capturing emissions at the plant, separating the CO_2 gas, compressing it to a supercritical liquid, and injecting it into deep saline aquifers that would indefinitely retain the fluid (Smith et al., 2002). The option is attractive in the Midwest because there are regional deep formations capable of accepting large quantities of CO_2 (Bergman and Winter, 1995; Gupta et al., 2002).

The Ohio River Valley Region is an area with large CO_2 emissions from hydrocarbon-based energy infrastructure (Figure 1-1). Because of the emissions, there is a strong incentive for local CO_2 sequestration in the underlying geologic strata, including deep saline reservoirs. The Ohio River Valley CO_2 Storage Project has a regional significance because the economy of the region is dependent on the cheap and plentiful fossil-fuel based energy. Regionally, the presence of geologic formations having sufficient permeability, storage capacity, and containment to serve as suitable sequestration reservoirs has been demonstrated (Gupta et al., 2001; Gupta et al., 2004). This is exemplified by the presence of oil and natural gas production and underground waste disposal and natural gas storage facilities that utilize the Mt. Simon and Rose Run sandstones, as well as several other formations. However, due to lateral heterogeneities and stratigraphic transitions, suitable sequestration reservoirs are not assured in close proximity to many large CO_2 sources. This may be especially true in the eastern and southeastern parts of the Ohio Valley where less favorable carbonate and shale facies appear to predominate over the thick continuous sandstones, the latter being prevalent in the rest of the Midwestern states. This report presents results from initial field investigations from the site characterization effort as well as some implications of the geologic setting on the future implementation of carbon capture and storage in the region. Depending upon the geology and reservoir characteristics, the ultimate objective for this project is to progress towards demonstration of CO_2 injection in deep geologic reservoirs. An effort was made to ensure that if a decision to proceed to an injection phase was made, the current test well would be able to meet the relevant regulatory criteria.

The objective of this report is to assess the potential for geologic storage of CO_2 in the Ohio River Valley region. In addition to this report, a preliminary geology topical report which was prepared prior to field characterization was submitted in 2003, and a work plan for the field characterization was also submitted in 2003. Site characterization, design and feasibility, and modeling and risk assessment topical reports have also been prepared in conjunction with this final technical report. This report includes an evaluation of the deep saline reservoirs and caprock formations with the objective of providing practical maps, data, and guidance to implement CO_2 storage projects in southeastern Ohio. Topics covered include geologic background of the region; a brief discussion of the Mountaineer CO_2 storage test well; other regional characterization efforts in the area; a discussion on the design, reservoir simulations, and monitoring aspects; and conclusions on sequestration potential. The report includes pertinent information on the CO_2 storage test well at the Mountaineer Power Plant and three other wells in the region that were investigated to better define CO_2 storage targets in the region. The information is designed to support full-scale injection design, permits, and system application at power plants in the study area.

Suitable formations for geologic storage of CO_2 are deep, thick, regions that are regionally extensive, filled with saline waters, and separated from freshwater aquifers and other formations of economic interest by a significant interval of low permeability caprock. For CO_2 disposal applications, a minimum depth of approximately 2,500 ft is required to maintain the pressure for retaining CO_2 in a dense, supercritical fluid phase. The supercritical CO_2 generally remains in a separate phase, but eventually a portion of the fluid dissolves in formation liquids and may transform to minerals in rock-water reactions. The practice of CO_2 injection has been safely used for enhanced oil recovery in more than 70 oil fields over the past few decades (Reichle et al., 1999). Additionally, there are many natural analogs where naturally occurring CO_2 has been trapped and accumulated in underground reservoirs and has remained for millions of years (Allis et al., 2001). Finally, deep well injection of liquid hazardous or nonhazardous waste, including large quantities of oil brines, has been performed throughout the United States for several decades and is an established practice (Apps and Tsang, 1996).

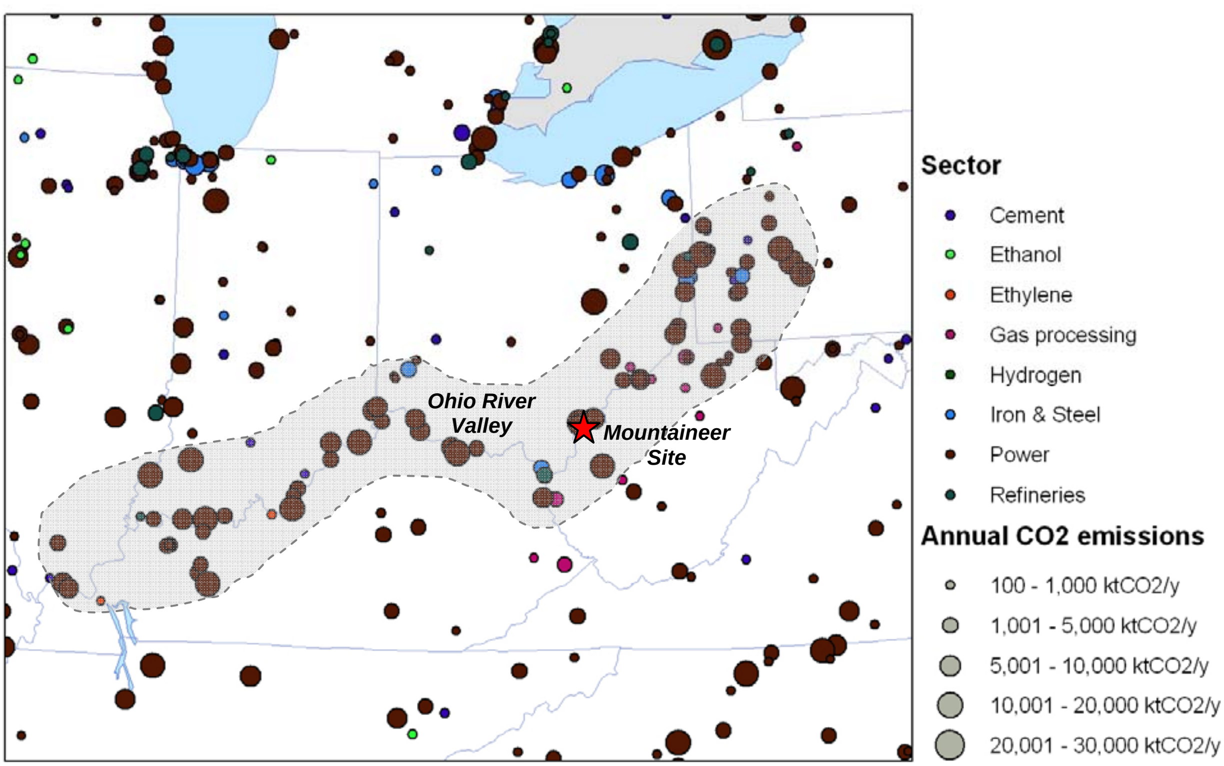


Figure 1-1. Map of Major CO_2 Point Source and Approximate Ohio River Valley Area

Section 2.0: GEOLOGIC BACKGROUND

Understanding the geologic setting is critical for selecting suitable rock formations for injection where the fluid injected will remain for long periods of time. Sequences of Paleozoic age (250 to 570 million years old) sedimentary rocks 2,000 to 20,000 ft thick form broad regional structures in the eastern and midwestern United States. Southeastern Ohio lies within the Appalachian Basin where rock layers slope to the east. The sedimentary rocks overlie dense metamorphic and igneous rock and form the base of continental plates. The sedimentary rocks consist of shale, limestone, siltstone, and sandstone. This section summarizes regional geology as it applies to CO_2 storage potential in southeastern Ohio including regional geology, structure, seismic activity, coal-bed methane applications, and injection reservoirs.

2.1 Regional Geology

Thick sequences of sedimentary rocks of Paleozoic age (250 to 570 million years old) form broad regional structures in the eastern and midwestern United States (Figure 2-1). The Ohio River Valley extends from the Appalachian Basin, an area from New York to Tennessee where rock formations slope toward the east, to the Cincinnati Arch to the west, into the Illinois Basin. Within the Appalachian Basin are several physiographic provinces having similar landforms. The study area is located in the Plateau Province. In this province, erosion has subdued the uplifted landscape into hilly upland areas. To the southeast the Valley and Ridge Province exist where elongated ridges and valleys border the Blue Ridge Mountains. Flatter landforms of the central lowlands are located to the west of the Plateau Province. The province extends considerably to the southwest and northeast of the study area.

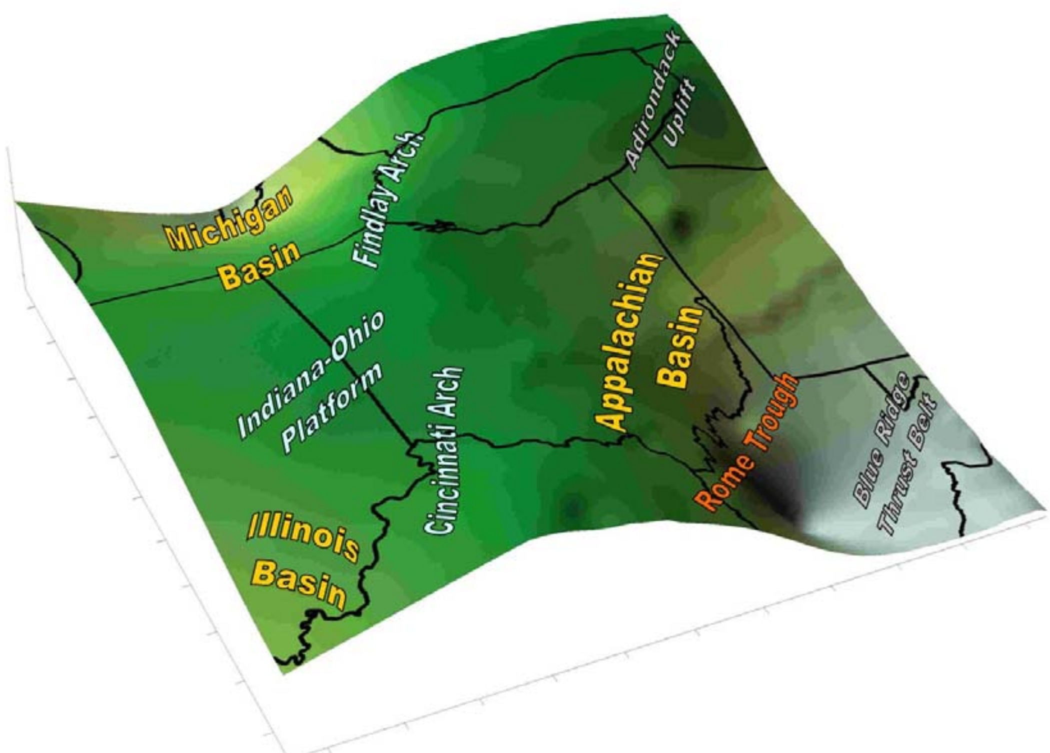


Figure 2-1. Major Regional Structures Around the Study Area

In the region, sedimentary rocks 3,000 to over 15,000 ft thick overlie Precambrian metamorphic and igneous rock. The Precambrian rock consists of gneiss and granite associated with ancient mountain building in the area. This rock forms stable continental cratons that are the base of tectonic plates. Above the Precambrian rock, sedimentary rock consists of alternating layers of sandstone, limestone, dolomite, siltstone, and shale. These rocks reflect transgressive seas that existed in the area in Paleozoic times. Layers with similar properties are termed "formations" and can be traced throughout the region to outline geologic structures and physiographic provinces. In the Appalachians, several mountain building events have gently folded the rock layers in the study area. The rock layers vary in thickness, and several formations are limited in extent. Toward the southeast of the study area, the rocks are more intensely folded and faulted along the Blue Ridge Thrust Belt.

Sedimentary rocks in the study area have been categorized by geologists and drillers based on rocks encountered during drilling. Much of the information has come from oil and gas exploration activities. With a column of up to over 15,000 ft of sedimentary rocks, numerous formations have been identified in the study area. Terminology for the rock formations varies with location and time, but the general stratigraphy can be traced throughout the region (Figure 2-2). State Geological Surveys maintain the official terminology, but it is useful to recognize historical formation names and driller's terms.

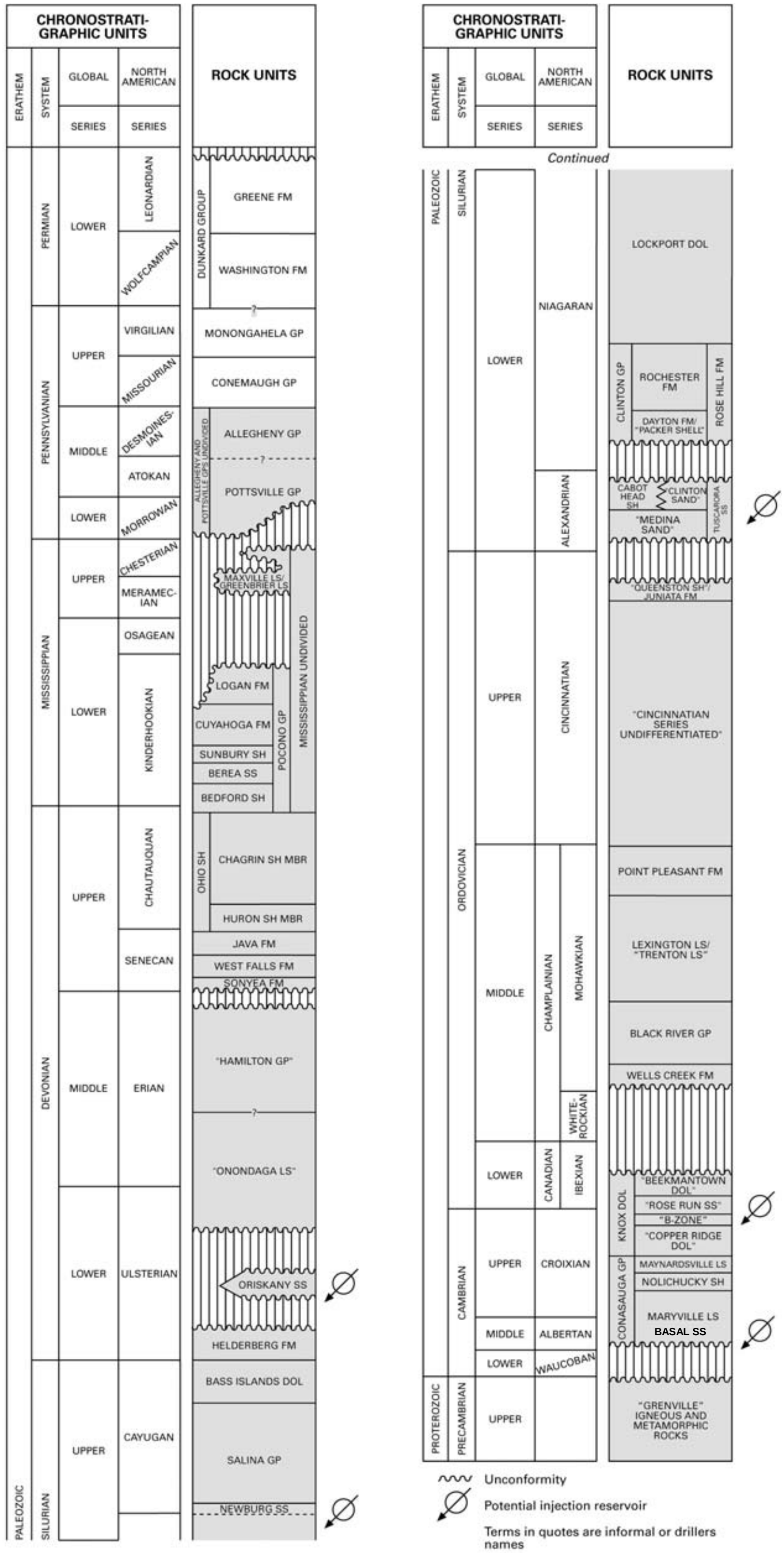
Metamorphic and igneous Precambrian rock of the Grenville Province form the base or craton of continental plates. At the base of the Paleozoic sedimentary sequence is the Mt. Simon sandstone or Basal sandstone. Overlying the Mt. Simon is the Conasauga/Nolichucky, which is equivalent to the Eau Claire formation in the region. The next formation is the Rome formation, which is dolomite with low porosity and permeability. The Rome formation thins in eastern Ohio and transitions to the Copper Ridge. This formation is followed by a dolomite termed the Copper Ridge and the Rose Run, a sandstone unit that appears in eastern Ohio and extends into the eastern Appalachian Basin. The formation marks the youngest Cambrian rock in the area.

Lower Ordovician rocks include the Beekmantown, Wells Creek, Black River Group, Trenton, and Point Pleasant. These formations are mostly shale, limestone, and dolomite. Between the Beekmantown and the Wells Creek is a major unconformity, or erosional surface, marking a gap in the sedimentary record. This 'Knox Unconformity' can be traced throughout the region and is a significant marker in geological investigations. The Copper Ridge, Rose Run, and Beekmantown are often referred to as the Knox Group. The Reedsville and Juniata formations form shale layers with a combined thickness of over 1,000 ft in the upper Ordovician rock column. These shale layers correspond to the Cincinnati Series in other parts of the Midwest.

At the base of the Silurian is a series of sandstone and limestone units including the "Medina Sand," "Clinton Sand," and Dayton formation. The "Clinton Sand" is a significant gas reservoir in the region with over 60,000 gas wells. The overlying Dayton limestone is often referred to as the "Packer Shell" by drillers. The Rochester Shale formation overlies the Dayton formation in the area. The Lockport, Salina, and Bass Islands formations are present in the upper Silurian. These formations are mostly limestone and dolomite sandstone. Within the Lockport is a high permeability sandstone termed the "Newburg."

Within the lower Devonian is the Helderburg formation and the Oriskany sandstone. The Oriskany is clean sandstone that suboutcrops in eastern Ohio. The Onondaga limestone overlies the Oriskany unconformably. Several sandstone and limestone layers exist above the Onondaga, including the Hamilton, Sonyea, West Falls, and Java formations. A major shale formation often termed the Ohio Shale marks the Upper Devonian in the study area.

A series of sandstone and shale units exist in the lower Mississippian interval. The Bedford shale, Berea sandstone, Sunbury shale, Cuyahoga, and Logan formations are found within the lower Mississippian



Stratigraphic nomenclature for southeastern Ohio and northwestern West Virginia. (Modified from Larsen, 1998)

Figure 2-2. Stratigraphy for the Study Area

column. Pennsylvanian and early Permian rocks are generally the youngest formations found in the study area and comprise surficial rocks. Formations include the Pottsville, Allegheny, Connemaugh, Monongahela, and Dunkard. Coal plays are found in several of these formations. Unconsolidated sediments overlie bedrock in much of the study area. The sediments are a mixture of clay, silt, sand, and gravel associated with erosion and rivers. These unconsolidated deposits often form groundwater aquifers that are used as a source of drinking water in the region.

There is some potential for uncontrolled deep well injection to trigger earthquakes, especially in areas with preexisting faults (Healy et al., 1968; Raleigh et al., 1976; Sminchak and Gupta, 2003). Geologic structures, fault lines, and seismic history are indicators of seismic suitability. Paleozoic rocks in the Midwest are generally uniform, flat-lying or gently-dipping, sedimentary rock layers with conformable contacts, and seismic activity is generally low throughout the midwestern and eastern United States. Most seismic events with epicenters in the region have magnitudes of less than 3.0 on the Richter scale.

In terms of seismic hazards, the United States Geological Survey (USGS) classifies the study area as low risk. The USGS National Seismic Hazard Mapping project integrates seismic history, geology, and land type to represent the chances that a given location will have a damaging earthquake. Overall, most of the Ohio River Valley is not within a seismically active zone. The area with the higher seismic hazard is toward the western extent of the valley. There is little risk of an earthquake damaging the injection well, and the potential for induced seismicity in Paleozoic rocks is low.

Section 3.0: MOUNTAINEER CO_2 STORAGE TEST WELL

A test site was selected to demonstrate CO_2 storage in deep saline formations in the Ohio River Valley. The site is located at the AEP Mountaineer Power Plant in Mason County, West Virginia, outside of New Haven (Figure 3-1). The objective of the test well was to site an injection well on an operating coal-fired power plant to demonstrate and evaluate the feasibility of CO_2 storage in the Ohio River Valley (Jagucki et al., 2003). The project was sponsored by the DOE, AEP, Ohio Coal Development Office (OCDO), and BP with in-kind contributions from Battelle, the Ohio Department of Natural Resources (ODNR), and Schlumberger.

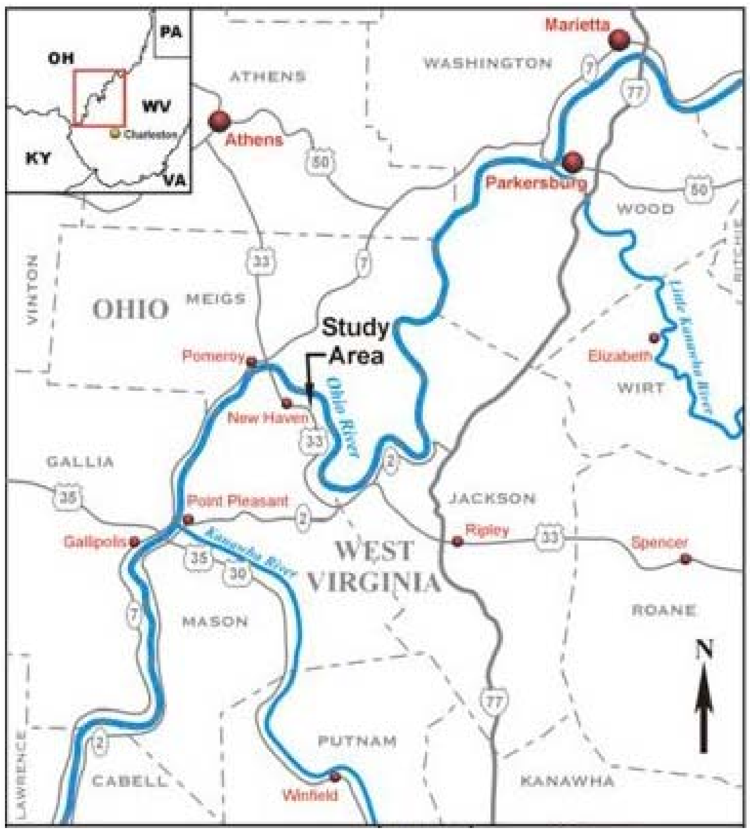


Figure 3-1. Study Area Location

This project site represents a typical potential CO_2 storage locale for the Ohio River Valley. As such, it provides information on procedures for laying the groundwork for CO_2 storage at power plants in the area. Site characterization at the Mountaineer Plant was divided into the following major categories:

1. Drilling an exploratory borehole
2. Seismic survey
3. Wireline testing in the borehole
4. Rock core collection and testing
5. Reservoir testing.

In addition, the borehole location fills a major data gap in geologic coverage of deep rocks in Ohio. Data collected from the test well will help identify and describe key rock formations for CO_2 storage in the Ohio River Valley.

The site lies along the Ohio River near many coal power plants and provides a research location for much of the Ohio River Valley. Although the site geology presents several challenges, the study site is a fairly typical location for coal-fired power plants in the region, and experience from this project could be applied to several other locations that are more conducive to injection. The well drilling program was designed to explore all potential reservoirs, many of which are overlooked in oil and gas drilling in the region. In addition, the well was constructed to meet West Virginia Department of Environmental Protection Agency Underground Injection Control regulations.

The Mountaineer Power Plant has been in operation since 1980. The plant has a single 1,300-MW coal-fired steam electric generating unit that burns low sulfur coal and is equipped with electrostatic precipitators for particulate emissions control (Figure 3-2). Condenser cooling water for the unit is provided by a recirculating water system utilizing a natural draft hyperbolic cooling tower. The plant is considered to be one of the "next-generation" coal-burning power plants, as it is designed to incorporate elements of clean coal technology, including SO_x and NO_x scrubbers and possibly CO_2 scrubbers. Currently, the plant operates with a NO_x scrubber and a SO_x scrubber was installed in 2006.

Figure 3-2. Mountaineer Power Plant

3.1 Well Drilling Program

A 9,190-ft deep well was completed on the AEP Mountaineer Power Plant site to characterize CO_2 storage opportunities in the region. The borehole penetrated into granitic Precambrian basement rock. Drilling took 90 days and included comprehensive downhole logging and rock coring. Multiple casings were installed in the upper 6,285 ft of the well. The last 2,905 ft was left open hole so that all storage reservoirs could be explored. Well construction methods were designed to facilitate CO_2 injection in the well. Construction included multiple casings and acid-resistant cement. Site protection and restoration measures were taken to ensure that the drilling did not affect plant operations or present any risk to human health or the environment. The well represented a fairly typical location of the Ohio River Valley. However, as learned in the drilling effort, site-specific conditions must be determined from a boring on location.

The field effort, including site setup, drilling of the test well, downhole and wireline data collection, and site restoration, was conducted between April and November of 2003. Rig mobilization, drilling, demobilization, and data collection efforts were conducted from approximately May 14, 2003 to August 15, 2003. This section of the report discusses drilling of the test well and final well construction.

The drilling objectives were to complete the borehole to target depth in pre-Cambrian basement rocks at approximately 9,200 ft, to set all but the final string of casing, and to collect wireline data and rock and brine samples from as many formations as possible. A drilling work plan was prepared for the effort (Jagucki et al., 2003). The plan details site preparation, methods, materials, and health and safety precautions. It should be noted that the well drilling, construction, and testing were designed to meet requirements of waste disposal wells and the needs of an innovative CO_2 storage research program. As such, much more effort was allotted to the characterization of the borehole than is typically done for gas wells in the region, even though many of the methods used in the oil and gas industry were employed.

Several drilling runs were completed for the test well. After the target depth was reached, wireline logging and/or casing was installed in the borehole and cemented in place. Initially, a conductor casing was set to a depth of 25 ft followed by another conductor casing to a depth of 84 ft to seal the shallow aquifer from the borehole. Drilling then proceeded in five runs termed the *shallow surface, shallow intermediate, intermediate, deep intermediate,* and *deep run*. Casing was set and cemented after each run up to the deep intermediate. The final section of the borehole was left open. Figure 3-3 shows a diagram of the well as completed in August 2004.

3.2 Wireline Logging Program

A full suite of wireline logs was completed to obtain a continuous log of the rock formations in the test boring. Continuous logs of petrophysical properties were obtained by lowering tools on wireline cables within the borehole. Wireline methods were valuable in identifying potential CO_2 storage reservoirs in the boring. Although wireline logs are commonly run in oil and gas wells, a different approach was necessary to delineate reservoirs and caprocks. Interpretation of wireline logs was the main method used to outline stratigraphy in the boring. The logs suggested mostly carbonate rocks in the well with isolated zones of high porosity/permeability in the Beekmantown, Rose Run, and Copper Ridge “B-zone.”

The wireline tool program was designed to collect information during well drilling and completion work. Formations in the open borehole were logged before placement of casing and cement, and wireline cement bond logs were run on completed sections of the well to ensure a good cement job. The majority of wireline work, including all sample collection, was concentrated on the production casing zone, which was left open at the bottom of the hole and contains the potential future injection zones. Figure 3-4 summarizes the wireline tools run in each section of this borehole.

Overall, the wireline logging indicated mainly carbonate rocks in the boring. Porosity was generally very low over the entire logging interval. The combinable magnetic resonance (CMR) log also indicated mainly low permeability of less than 0.1 milliDarcy (mD) throughout most of the boring. The main intervals of porosity and permeability were present in the Rose Run sandstone and Copper Ridge “B-zone.” Other intervals showed properties reflective of containment units. Reservoirs are discussed in more detail in Section 5.0.

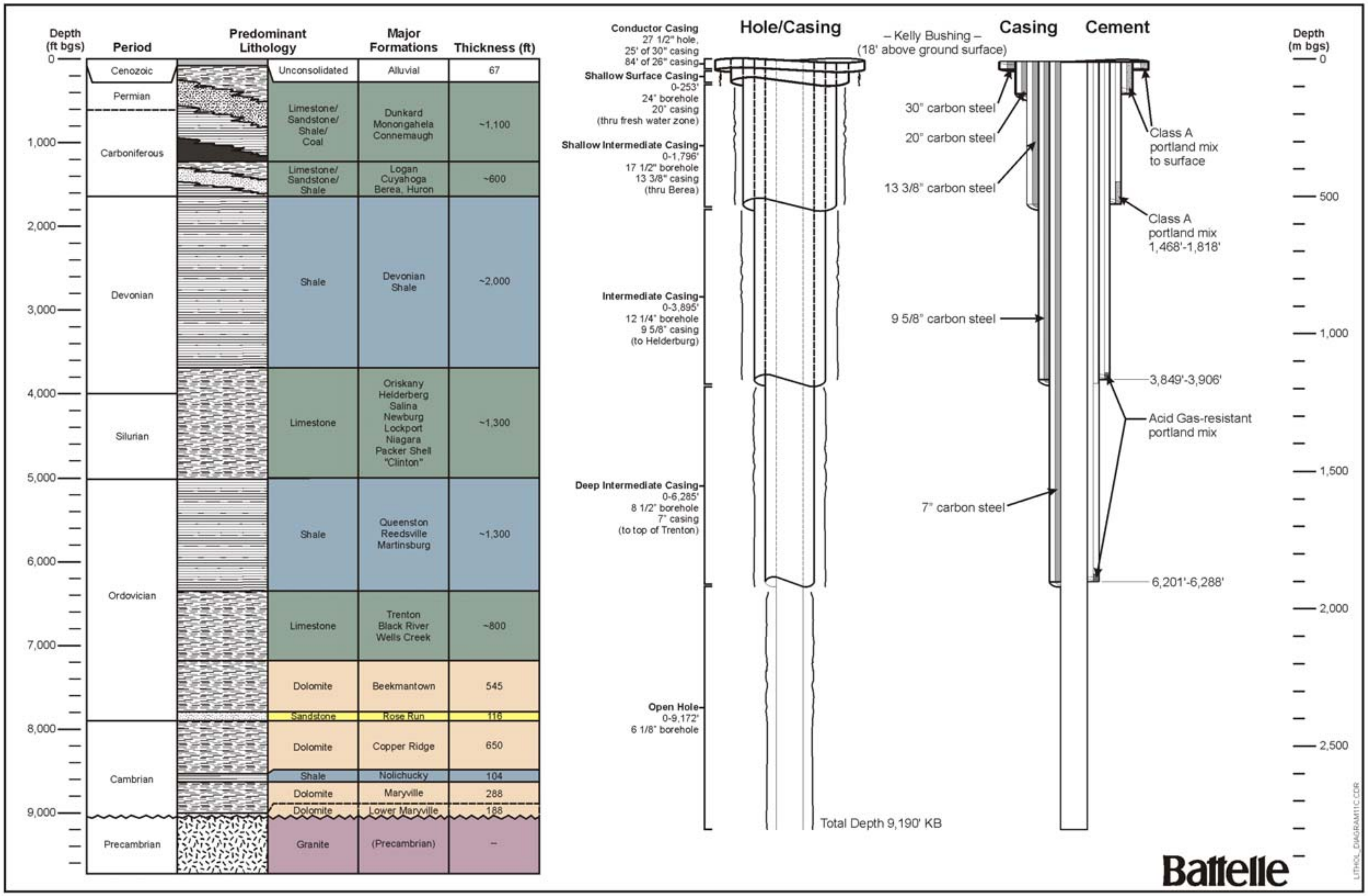


Figure 3-3. Summary of Test Well Construction

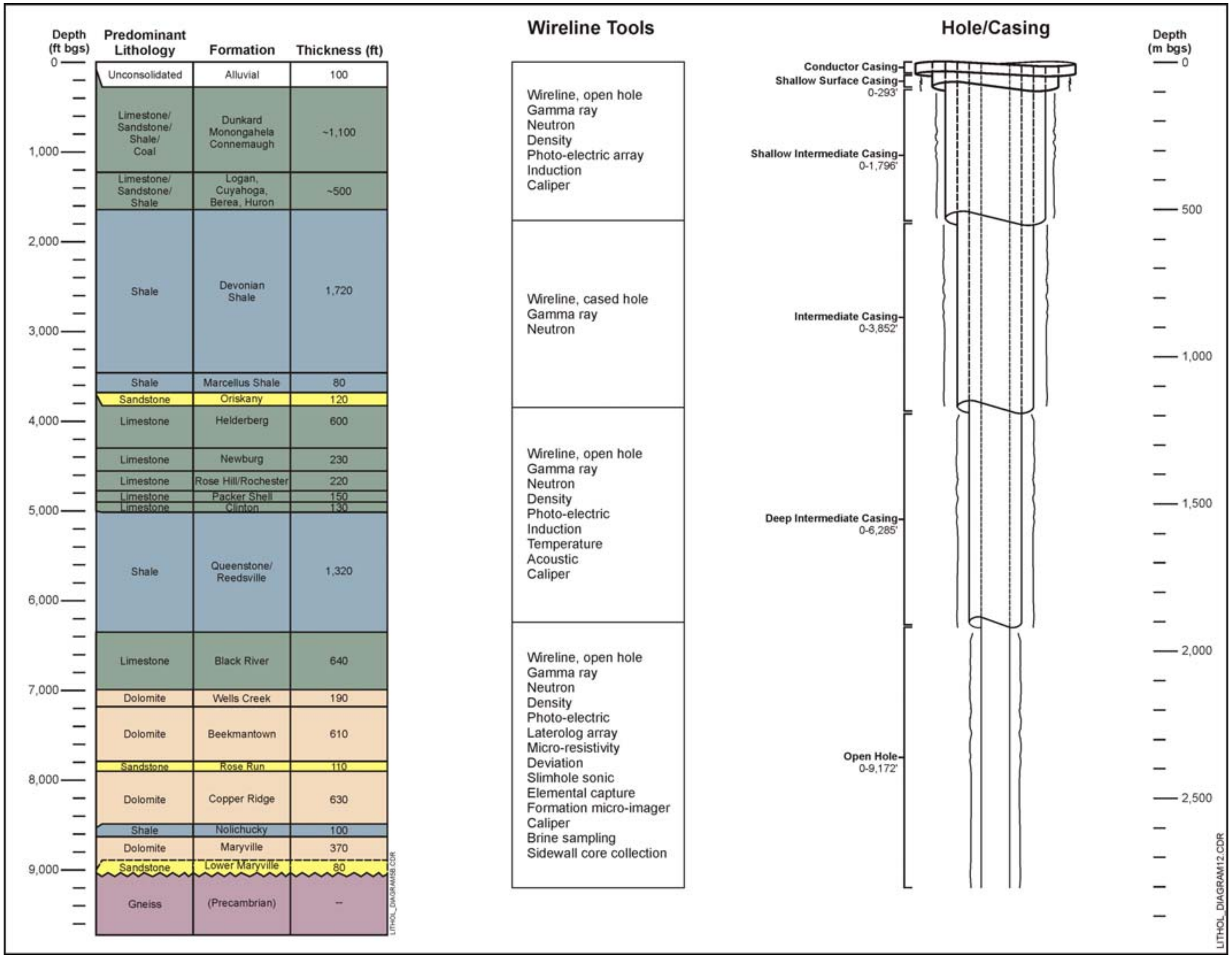


Figure 3-4. Wireline Tools Run in Test Well Borehole

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3.3 Seismic Survey

A two-dimensional seismic survey was completed through the test site to outline any deep geologic structures in the area. The survey consisted of a total of 11 miles in two transects running through the site. The seismic survey consisted of planning, data acquisition, processing of the seismic data, and interpretation of the seismic results. The objective of the seismic survey was to characterize the arrangement and structure of deep geologic formations. In addition, options for monitoring CO_2 injection in the subsurface with seismic methods was also explored (Gupta et al., 2004). In association with the drilling and reservoir evaluation, 14 miles of two-dimensional seismic surveying was completed through the site. This seismic survey consisted of two lines: line MP-01-03 with a northwest-southeast orientation, and line MP-02-03 with a north-northeast orientation. These lines intersected within several hundred feet of the well location (Figure 3-5).

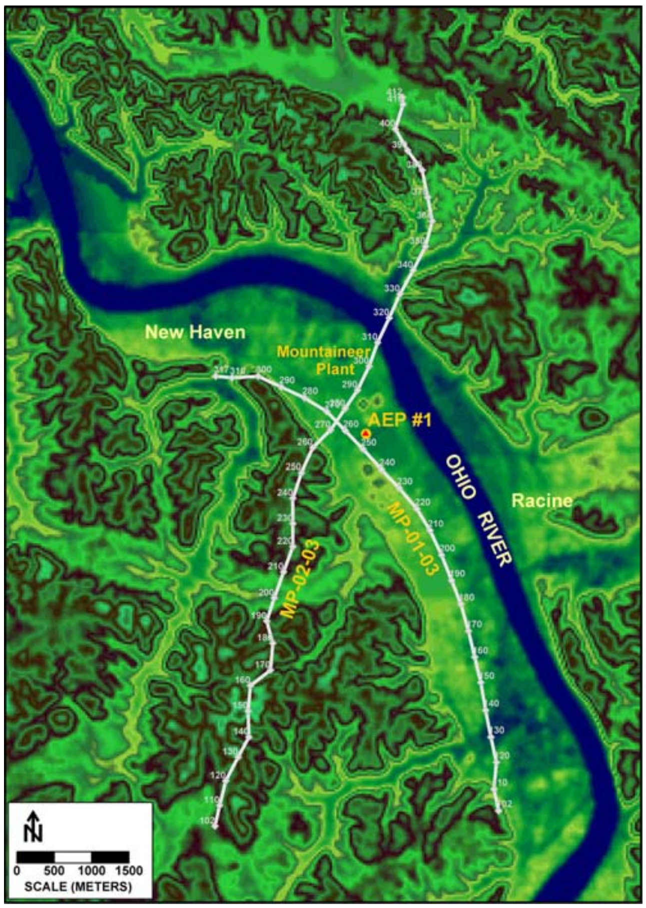

Figure 3-5. Seismic Survey Location Map for MP-01-03 and MP-02-03 Shown on a Digital Elevation Map (The Trace Follows a Slightly Crooked Line in Some of the Upland Areas.)

Overall, the survey results matched the results obtained from the borehole. The survey indicated that the rock formations consisted of continuous, flat-lying sedimentary rocks (Figure 3-6). No geologic structures were present. Substitution analysis suggested that the CO_2 front may be difficult to monitor with four dimensional seismic methods due to the limited thickness of the injection units.

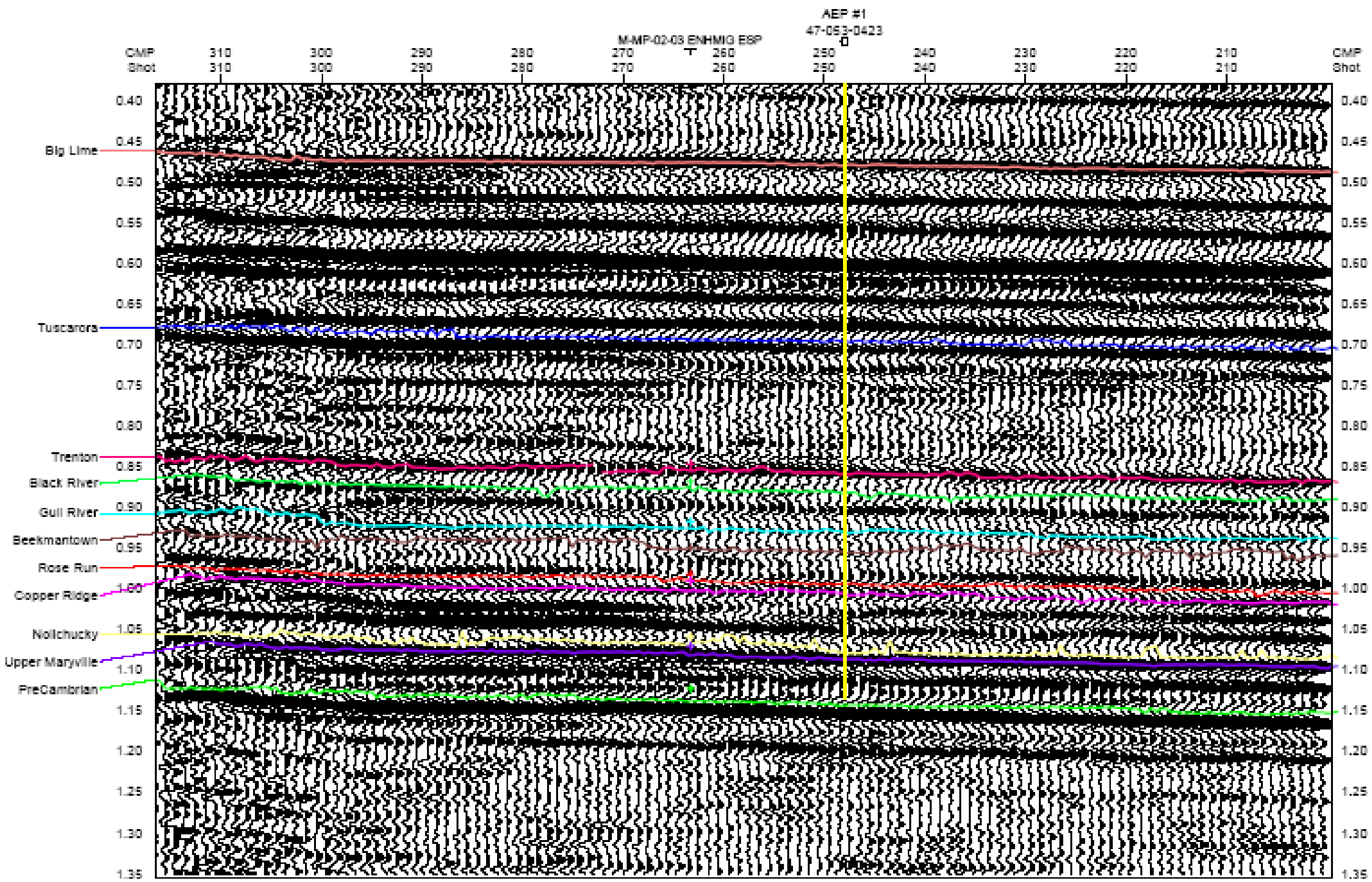

Figure 3-6. Full Section Presentation of Seismic Line MP-01-03, Showing Arrangement of Deep Rocks Through the Project Site (The Survey Shows Continuous Rock Layers Dipping Gently to the East-Southeast.)

3.4 Core Collection and Testing

A total of 290 ft of continuous, 3-inch-diameter rock core was collected from the boring. In addition, 23 core plugs were collected from key depth intervals (Figure 3-7). These cores represent a distinct dataset for southeastern Ohio because few (if any) rock cores have been collected from the deeper formations in the area. 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. Core tests suggested that much of the cored rocks had low porosity (less than 3%) and permeability (less than 0.1 mD).

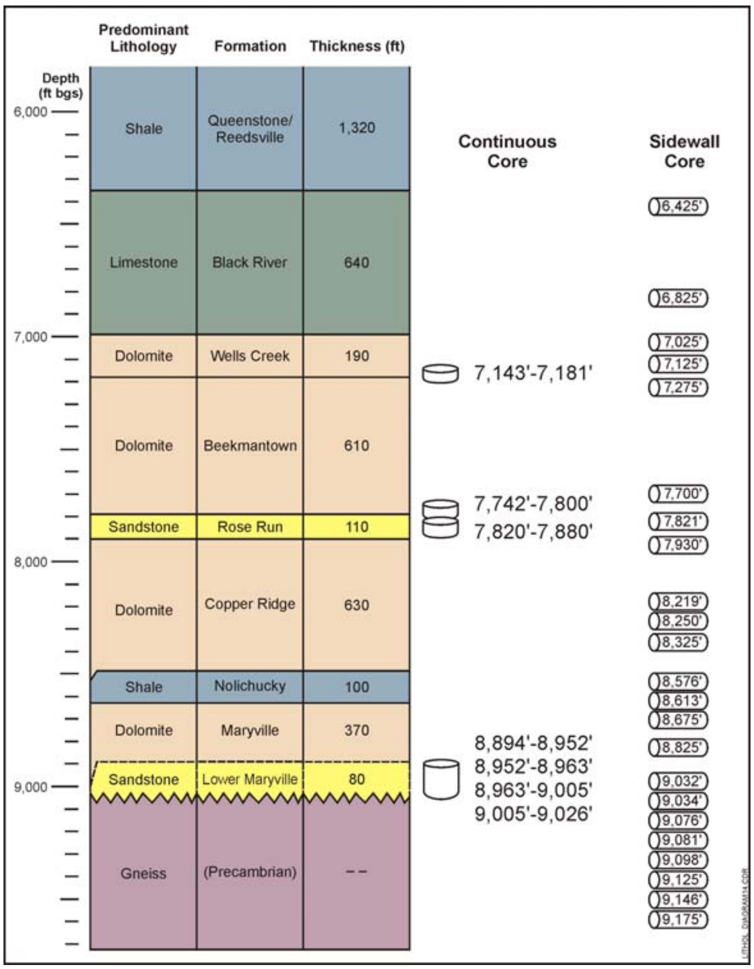

Figure 3-7. Summary of Coring Intervals

The rock coring strategy was designed to collect and test cores from potential injection reservoirs and key containment intervals. The objective was to determine key hydraulic, mineralogical, geochemical, and geomechanical properties of the rock formations. These parameters are critical in determining the potential for CO_2 storage at the Mountaineer site and the region in general. A total of 290 ft of continuous 3-inch diameter core (Figure 3-8) was collected from key depth intervals during drilling. The full cores allow for detailed examination of changes in lithology and extensive testing. In addition, 24 core plugs were collected from formations after drilling with wireline methods.

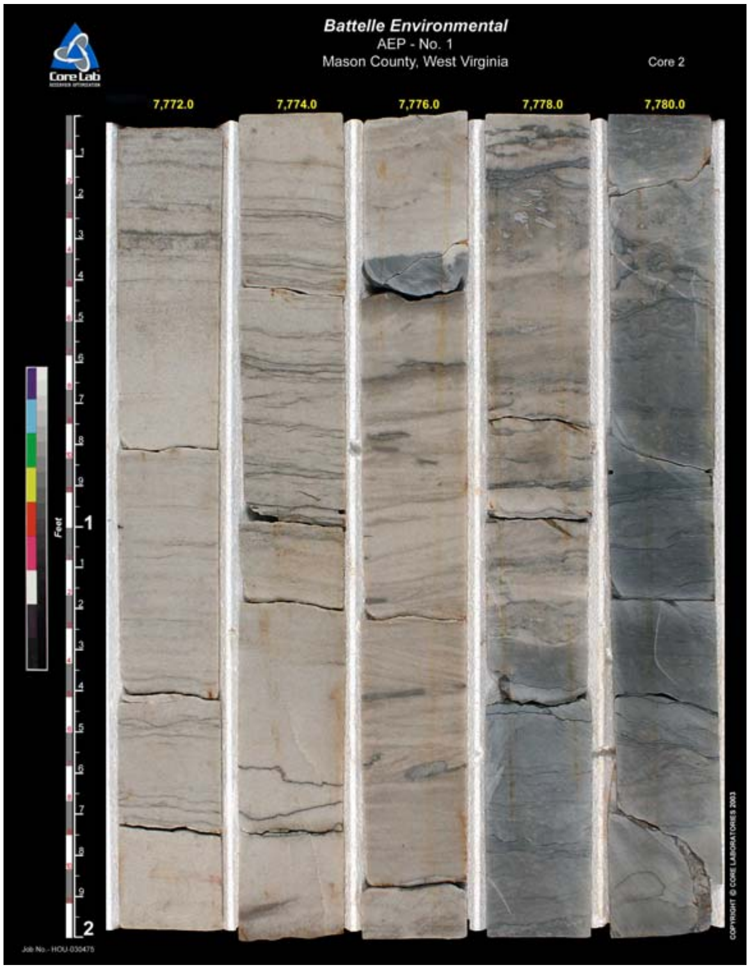

Figure 3-8. Example of 3-Inch Diameter Continuous Core (This Core was Collected From the Rose Run Sandstone at a Depth Interval of 7,772 to 7,782 ft.)

A reservoir interval was identified in the Rose Run sandstone at a depth of 7,760 to 7,780 ft with porosity of 8 to 13% and permeability up to 70 mD. Most of the Rose Run samples are medium-grained, moderate to poorly sorted arkosic arenites and subarkosic arenites. The dominant framework mineralogy consists of detrital quartz and K-feldspar and minor amounts of plagioclase feldspar, rock fragments, and heavy minerals. Geomechanical tests suggest that the reservoir rocks would be more receptive to hydrofracturing while the containment layers have more competent rock properties that would be unlikely to fracture. CO_2 and methane adsorption isotherms for Devonian black shale samples from the well indicated that this formation has an organic content of approximately 4.5%. The testing indicates that there is potential for CO_2 sequestration and enhanced natural gas production in the Devonian shales.

3.5 Reservoir Testing

Two stages of the reservoir testing program were conducted at the AEP No. 1 Mountaineer Power Plant test borehole in March/April 2004 and October 2005. The objective of the testing program was to characterize the hydrogeologic conditions and sequestration potential of candidate reservoir formations. The results from earlier characterization activities provided a geologic description and initial hydraulic assessment of key formations. Earlier activities focused on the Rose Run formation and the Lower

Marysville/Basal Sandstone formation, which are important regional reservoirs for the disposal of brines and hazardous liquid wastes.

The field test activities were completed using a three-phased approach, with each phase having different characterization objectives (Figure 3-9). The primary Phase 1 objective was to provide an initial reconnaissance of the distribution and location of higher permeability zones within the open borehole section. This was accomplished through use of dynamic fluid logging survey (flowmeter and fluid temperature) conducted during an open borehole, air-lift pumping test. Results from Phase 1 were used in the selection of reservoir and caprock zones for detailed hydrologic characterization in Phase 2. A wide-spectrum of Phase 2 testing activities were employed, which relied on the use of a downhole straddle-packer/pressure probe system to isolate the targeted horizons for detailed characterization testing. Specifically, quantitative in situ characterization information was obtained pertaining to: hydraulic and storage properties of candidate reservoir zones; hydrochemical content of reservoir brine solutions; and threshold formation fracture pressures for a selected reservoir zone and adjacent caprock horizons. Phase 3 utilized an abbreviated hydrologic characterization program of testing progressively larger composite sections of the open borehole. The objective of Phase 3 was to extend hydraulic property characterization to comparatively larger borehole sections, which could then be used with the results from Phases 1 and 2 for improving the conceptual relative distribution of permeability within AEP No. 1.

Results from the field testing program indicate that reservoirs intersected by AEP No. 1 collectively have a moderate transmissivity of 7.9 ft^2/day. The Rose Run formation, which is a regionally important formation for the storage of brines and hazardous fluids, only represents 10% or 0.78 ft^2/day of the overall composite borehole transmissivity. Results of mini-frac testing indicate that the minimum threshold fracture pressure for the Rose Run, 985 pounds per square inch (psi) above static formation pressure conditions, is significantly lower than indicated threshold fracture pressures for overlying/underlying caprock horizons. This suggests that the formational permeability and storage characteristic for the Rose Run formation may be enhanced utilizing hydrofrac and well completion technologies without compromising the sealing/sequestering properties of overlying and underlying confining layers.

Attempts to conduct detailed characterization of the isolated Lower Marysville/Basal sandstone formation, another regionally recognized storage reservoir, were unsuccessful due to test equipment failure. However, results obtained from Phase 1 and 3 testing suggest that this unit has lower permeability characteristics than exhibited by the Rose Run formation.

Results from the field testing program also identified several untested depth intervals that possess a significant percentage of the composite open borehole transmissivity. The most important of these is a 150-ft zone within the Copper Ridge "B-zone" formation at a depth interval of 8,150 to 8,300 ft. This zone was investigated in the October 2005 stage of reservoir testing. These field test activities were completed using a two-phased approach, with each phase having different characterization objectives. The primary Phase 1 objective was to provide an initial reconnaissance of the distribution and location of higher permeability zones within the open borehole section. Results from the Phase 1 reconnaissance-level program indicate that reservoirs intersected by AEP No. 1 have a transmissivity collectively ranging between 3.5 and 7.0 ft^2/d, based on a homogeneous formation conceptual model, and an assumed composite value for storativity, S, of 1.0E-5. There is a large uncertainty, however, associated with characterization results obtained from composite borehole constant-drawdown tests. This is due to the test analysis sensitivity in the presence of multiple producing zones (having different head conditions) and borehole skin effects (i.e., borehole damage and associated permeability reduction zone), and the fact that different combinations of T and S will provide similar surface discharge responses.

In Phase 2, multiple hydraulic tests were conducted as part of the detailed characterization of the Copper Ridge test interval. Best estimate characterization values for the Copper Ridge test interval were obtained

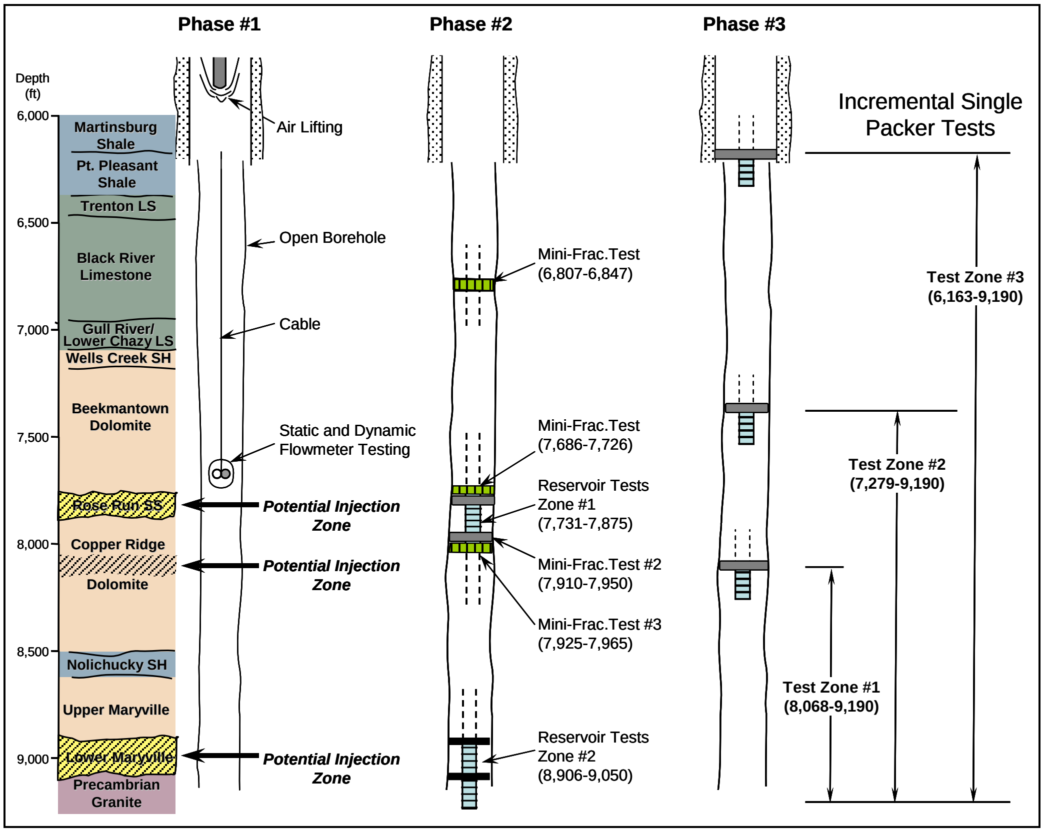

Figure 3-9. Schematic Diagram Outlined Three Phases of Reservoir Testing

from multiple history match analysis and indicated a transmissivity, T = 60.3 ft^2/day, hydraulic conductivity, K = 1.72 ft/day (0.708 Darcies), using an assumed storativity value of 1.0E-5, and a positive well-skin value of +47. The K value of 1.72 ft/day is based on a contributing effective thickness, b, within the isolated test interval, L, (i.e., 8,159 to 8,359 ft). A static formation pressure of 4,076.63 psia was calculated for the Copper Ridge test interval based test formation projection.

3.5 Numerical Simulations and Risk Assessment

Numerical simulations and a risk assessment were performed for the CO_2 storage assessment at the Mountaineer site. The numerical simulations are based on site specific characterization data and testing from the test well at the Mountaineer site. Injection simulations were completed to determine overall injectivity in the Rose Run sandstone and the Copper Ridge “B-zone.” Results were analyzed to determine estimated operational limits, storage mechanisms, and the behavior of the CO_2 in the storage target. Smaller, test-scale injection simulations were also completed to support activities related to a pilot-scale carbon capture and sequestration system. The main risk assessment tasks included a “features, events, and processes” (FEP) screening of the site for CO_2 storage. Additionally, an integrated risk analysis was completed for the project.

3.5.1 Numerical Simulations

Numerical simulations of CO_2 injection have been conducted as part of a program to assess the potential for geologic sequestration in a deep brine reservoir at AEP’s Mountaineer Power Plant in New Haven, West Virginia. Site characterization data, including borehole logs, core samples and hydraulic tests

(Gupta et al., 2005), have been used to develop simulations of CO_2 injection into the Rose Run and Copper Ridge formations under several scenarios, such as vertical and horizontal wells, full-scale and small-scale injection, injection pressure variations, and two- or three-dimensional model configurations.

Numerical simulation of CO_2 injection into deep geologic reservoirs requires modeling complex, coupled hydrologic, chemical, and thermal processes, including multi-fluid flow and transport, partitioning of CO_2 into the aqueous phase, and chemical interactions with aqueous fluids and rock minerals. The simulations conducted for this investigation were executed with serial and parallel versions of the STOMP-WCS (water, CO_2, salt) simulator (White and Oostrom, 2006). STOMP has been verified against other codes used for simulation of geologic disposal of CO_2 as part of the GeoSeq code intercomparison study (Pruess et al., 2002). Reactive transport simulations with equilibrium and kinetic reactions were conducted with STOMP/ECKEChem.

The objective of the Rose Run formation modeling was to predict CO_2 injection rates using data from the core analysis conducted on the Rose Run formation samples. A 129.5 ft interval was included in the model, between the true depths of 7711 to 7840.5 ft below Kelly Bushing (bKB), with low permeability zones at the top and bottom acting as caprock. Most simulations were conducted assuming two-dimensional radial symmetry about the well. To address uncertainty related to the availability of core data from only one well, several geostatistical realizations of the formation geology were used, all calibrated to formation transmissivity measured during hydraulic tests. An injection well pressure gradient of 0.675 psi/ft was assumed because this was less than the fracture pressure gradient of the overlying Beekmantown dolomite, which acts as a caprock. The injection phase was assumed to last for three years, with a 17-year recovery period. The resulting CO_2 injection rates after three years of injection varied between 56 and 589 ktonne/year, with an average value of 315 ktonne/year. The total CO_2 injected over this three-year period varied from 393 to 2631 ktonnes, with an average value of 1323 ktonnes. The radius containing 100% of the supercritical CO_2 mass varied between 2716 ft and 5688 ft, with an average value of 4276 ft, although most (90%) of the supercritical CO_2 is contained within an average radius of 753 ft, and half (50%) is contained near the well within an average radius of 26 ft.

The effect of salt precipitation was demonstrated by repeating the CO_2 injection simulation for the Rose Run base case without salt precipitation; this increased the CO_2 injection rate, increasing the total CO_2 injected over three years from 1096 to 1308 ktonnes. Sensitivity to injection pressure gradients was examined by varying modeled values to 0.55 and 0.8 psi/ft. The total CO_2 injected was 302 and 2040 tonnes for well injection pressure gradients of 0.55 and 0.8 psi/ft, respectively. Uncertainty in hydrologic information was addressed by varying the sandstone permeability and the sandstone capillary pressure-saturation characteristics. The relationship between permeability and amount of CO_2 injected is nearly linear, with total CO_2 injected over three years increasing by a factor of six for each ten-fold increase in permeability. The total CO_2 injected over three years is 1228 ktonnes for the Hygiene sandstone versus 1096 ktonnes for the Berea and 971 ktonnes for the Rose Run composite core sample. A longer 20-year injection period with an 80-year recovery period was simulated. The CO_2 injection rate decreases significantly during the first 3.6 years of injection, declining from 690 ktonnes/year to 269 ktonnes/year, and then increasing 20% to a rate of 324 ktonnes/year after 10 years of injection. The total amount of CO_2 injected over the 20-year period is 6340 ktonnes.

Pilot-scale injection into the Rose Run formation was simulated with constant CO_2 injection rates varying from 11 to 165 ktonnes/year. Simulations were carried out with porosity/permeability distributions that proved to have the lowest, mean and highest injectivities. Of interest in respect to potential monitoring well location is the radial extent of measurable changes in CO_2 saturation in the formation. The radius containing all (100%) of the injected supercritical CO_2 varied from 1085 for the 11 ktonne/year injection rate to 4243 ft for the 165 ktonne/year injection rate. However, the radius may be decreased with lateral wells or by injecting into both the Copper Ridge and Rose Run.

Several three-dimensional simulations of CO_2 injection into the Rose Run formation were run to assess the effect of a horizontal well, a scenario with a 2% regional dip, and multiple wells. The vertical well base case was repeated in 3D. The total CO_2 injected for the three-dimensional base case is 681 ktonnes, less than the two-dimensional base case (1096 ktonnes), but falling within the range of the highest and lowest two-dimensional simulations (393 to 2631 ktonnes) based on 11 geostatistical realizations. A 1000-ft horizontal well is able to inject 11% more CO_2 over a three-year period than a vertical well, and a 2100-ft horizontal well is able to inject 26% more CO_2 over the same period. The amount of CO_2 injected for a three-dimensional model with a 2% regional dip, 681 ktonne, was identical to the vertical well injection simulation with no regional dip. The total amount of CO_2 injected in three years by the six vertical wells (Figure 3-10) was 3565 ktonnes , which is 5.2 times greater than a single, vertical injection well. Reactive transport simulations indicate that carbonate dissolution does not significantly affect the rate of carbon sequestration in the Rose Run formation.

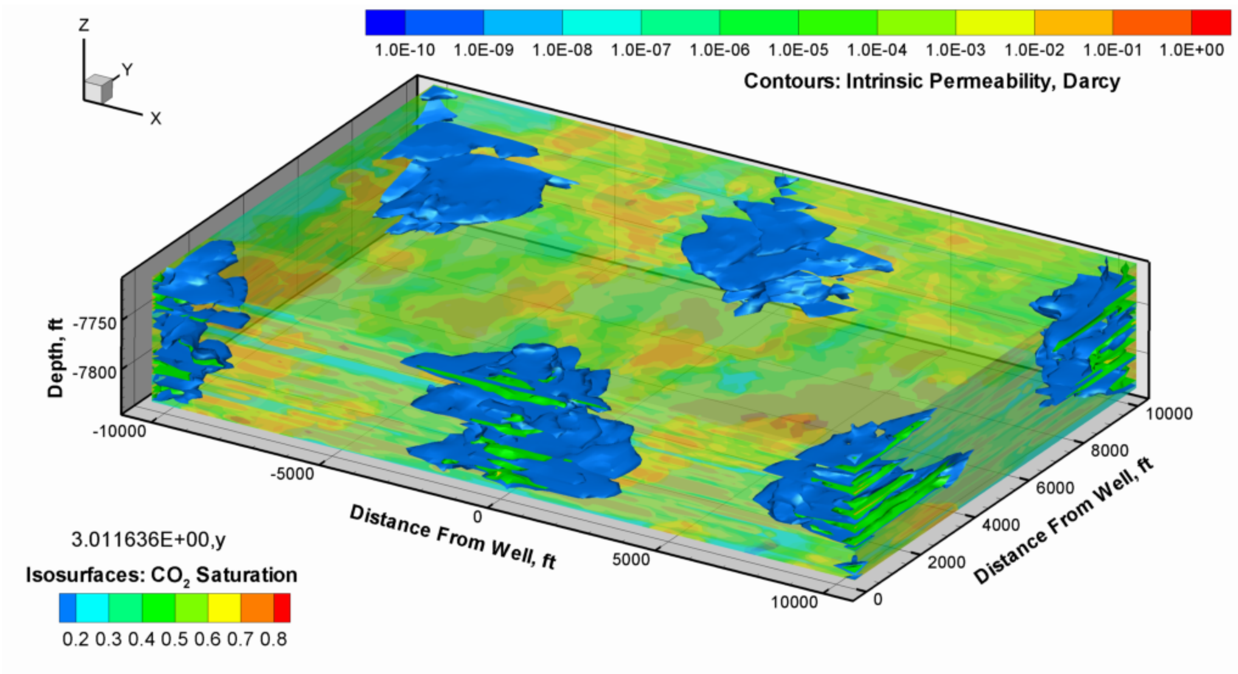

Figure 3-10. Supercritical CO_2 Saturation after Three Years of Multiple Well Injection into Three-Dimensional Simulation of the Rose Run Formation

The objective of the Copper Ridge formation modeling was to predict CO_2 injection rates using wireline log data calibrated to the results of hydraulic testing. A 260-ft thick interval was simulated between the true depths of 8053 to 8313 ft below ground surface (bgs) (survey depths of 8100 to 8360 ft bKB), with CO_2 injection into a 140-ft thick interval between the true depths of 8113 to 8253 ft bgs (survey depths of 8160 to 8300 ft bKB). Most simulations were conducted assuming two-dimensional radial symmetry about the well. To address uncertainty related to the availability of wireline log data from only one well, several geostatistical realizations of the formation geology were used, all calibrated to formation transmissivity measured during hydraulic tests. An injection well pressure gradient of 0.675 psi/ft was assumed, for comparison with the Rose Run formation simulations. The injection phase was assumed to last for three years, with a 17-year recovery period. The total CO_2 injected over this three-year period varied from 1575 to 3288 ktonnes, with an average value of 2246 ktonnes. The radius containing 100% of the supercritical CO_2 mass varied between 7539 ft and 9897 ft, with an average value of 7978 ft, although most (90%) of the supercritical CO_2 is contained within an average radius of 394 ft, and half (50%) is contained near the well within an average radius of 25 ft.

The effect of salt precipitation in the Copper Ridge formation was demonstrated by running a simulation without salt precipitation for comparison. Repeating the CO_2 injection simulation for realization without salt precipitation increased the CO_2 injection rate, increasing the total CO_2 injected over three years from 2069 to 5409 ktonnes. Sensitivity to injection pressure gradients was examined by varying modeled values between 0.55 and 0.8 psi/ft. The total CO_2 injected was 255 and 7772 tonnes for well injection pressure gradients of 0.55 and 0.8 psi/ft, respectively. Uncertainty in hydrologic information was addressed by varying the permeability and the capillary pressure-saturation characteristics. The relationship between permeability and CO_2 injection is nearly linear, with total CO_2 injected increasing by a factor of three to four for each seven-fold increase in permeability. The air-entry potential is inversely proportional to the injection rate at three years. Although the total CO_2 mass injected for the low air-entry pressure simulation is 31% higher than for the base case simulation, the total CO_2 mass injected for the high air-entry pressure simulation is also 5% higher than for the base case simulation. For the high air-entry pressure simulation, the injected supercritical CO_2 has a similar overall shape as the base case simulation, but there is less CO_2 mass close to the well than in the low air-entry pressure simulation. Because of this, there is less salting near the well for the high air-entry pressure simulation than for the low air-entry pressure simulation. A longer 20-year injection period with an 80-year recovery period was simulated. The CO_2 injection rate decreases rapidly during the first year of injection, declining from 1700 ktonnes/year to 500 ktonne/year, and then slowly decreasing to a rate of 329 ktonnes/year after 20 years of injection. The total amount of CO_2 injected over the 20-year period is 8623 ktonnes.

Pilot-scale injection into the Copper Ridge formation was simulated with constant CO_2 injection rates varying from 11 to 165 ktonne/year. Simulations were carried out with porosity/permeability distributions that proved to have the lowest, mean and highest injectivities. Of interest with respect to potential monitoring well location is the radial extent of measurable changes in CO_2 saturation in the formation. The radius containing all (100%) of the injected supercritical CO_2 varied from 1481 ft for the 11 ktonne/year injection rate to 4243 ft for the 165 ktonne/year injection rate.

The results of these simulations provide design guidance for injection and monitoring strategies, protocols, and permits for a demonstration project for CO_2 injection in these deep saline formations as well as support for integrated risk assessments. The results of simulations of CO_2 injections into the Rose Run and Copper Ridge formations, using permeability and porosity distributions based on geostatistical analysis, indicate that they are capable of receiving commercial-scale injection of CO_2 (up to several hundred thousand tonnes per well annually).

3.5.2 Risk Assessment A preliminary risk assessment was completed to analyze potential risks associated with the CO_2 storage project at the Mountaineer test well site. The evaluation was based on general CO_2 storage application or test-scale storage system. Experience with natural gas storage, enhanced oil recovery, natural CO_2 fields, and hazardous waste injection suggests that injection of CO_2 emissions into deep rock formations is a safe and practical technology, but there is some risk associated with application of geological storage. To address this potential risk, CO_2 sequestration has developed into a storage concept involving monitoring, measurement, and verification of the injected CO_2 to prove that the CO_2 is safely sequestered. However, a wide range factors may affect a storage project, and it is difficult to account for all these items in developing a monitoring program. In the risk assessment, a "features, events, and process" (FEP) screening was completed to identify items to consider in operating a CO_2 storage system at the test location. An integrated risk model was developed and applied to the Mountaineer site to evaluate potential for leakage and behavior of CO_2 into the environment.

FEP Risk Screening

The FEP database was developed by Quintessa to assess safety and performance of geological storage of CO_2 (Savage et al., 2004). The database is a generic list of all possible features, events, and processes that should be considered in any storage project. This systems analysis approach has been used for numerous applications, most notably radioactive waste disposal. A FEP screening approach was selected for the Ohio River Valley CO_2 Storage Project to aid in design of the injection system. The objective of the screening was to identify the main FEPs to be considered for the project.

The general screening approach was to analyze each item in the generic FEP database against the corresponding site-specific conditions at the Mountaineer site. A conceptual model of the site was developed describing the geologic framework, target storage reservoirs, containment units, brine chemistry, environmental conditions, and proposed injection rates. This information was then used in a sequential screening process aimed at identifying the main FEPs that apply to the project. Screening items were obtained from the "Generic FEP Database for the Assessment of Long-Term Performance and Safety of the Geological Storage of CO_2" (Savage et al., 2004). A stepwise approach was utilized to identify the FEPs that should be considered for the Ohio River Valley CO_2 Storage Project. Screening methods involved the following steps:

1. Compiling characterization data into a site-specific conceptual model
2. Primary screening level of FEPs for extremely unlikely items
3. Secondary screening level of FEPs that do not apply based on site characterization data or testing
4. Final compilation and evaluation of FEPs that bear further consideration
5. Providing recommendations on addressing identified FEPs into system design, monitoring, and application.

Initial screening identified items that were beyond human control, policy issues related to CO_2 storage concept, or legacy issues beyond the scope of a pilot-scale demonstration. The next level of screening examined the remaining FEP items in relation to site characterization results. If site information convincingly eliminated any concerns regarding the FEP, it was removed from further analysis. The remaining FEP items were compiled and analyzed to determine how they may affect the CO_2 storage project. Lastly, recommendations were made on how system design, monitoring, and storage application may be customized to address the FEPs identified in the screening.

Primary Screening – The objective of the primary screening was to eliminate items beyond human control, policy issues related to CO_2 storage concept, legacy issues beyond the scope of a pilot-scale demonstration, or other FEPs not applicable to the Mountaineer setting. The main FEPs removed in this screening included global climatic factors, biological processes, terrestrial environment, and marine features.

Secondary Screening – The secondary screening level compared remaining items to site characterization results. This level comprised the bulk of the screening effort. Many items in this screening can be accounted for with injection regulations, geologic conditions, brine chemistry, and/or the scale of the project.

FEP Screening Results and Conclusions

The final screening level involved a closer investigation of the remaining FEP items. A detailed response to the potential risk presented by the FEP item was developed based on site data and proposed storage specifications. Based on this list, recommendations were developed to address issues in well design, monitoring, and system operation.

Final Screening List – Table 3-1 provides the final list of FEPs that were identified in the screening process and response to these issues. In general, the final list fell into three categories: 1) variations in subsurface geology; 2) well completion materials; and 3) behavior of CO_2 in the subsurface. Geologic heterogeneities in the storage reservoir were seen as having the potential to affect pressures and fluid migration in the reservoirs. Interlayering of dolomite and sandstone was observed in the Rose Run sandstone, although Rose Run is laterally continuous in the seismic survey and regional maps. Well completion materials were identified as a category that should be considered in the storage project since they may affect containment along the injection well. Since no other wells penetrate the reservoir nearby, this issue mainly applies to the injection well and any future monitoring wells that penetrate the storage reservoir. FEP items relating to the properties of CO_2 and interactions of CO_2 were also identified in the screening process. CO_2 solubility and aqueous specification were mainly considered an important process because the formation brines is very concentrated with total dissolved solids of more than 300,000 mg/L.

Recommendations for System Design, Monitoring, and Application – Many options are available for addressing the FEPs identified in the screening study. Geological heterogeneities may be investigated with longer term reservoir tests which may detect any boundaries in the reservoir. In addition, operational monitoring of injection pressures should aid in detecting reservoir boundaries. Specialized well materials are an effective approach for ensuring the integrity of the well. Acid resistant cement, alloy injection tubing, and mechanical packers may be used to ensure a competent well. Cement logging and well workovers may also be performed to determine if well materials are degrading. Proper design and monitoring of the injection well can also aid in assessing well materials. Measuring pressures in interannulus fluids can provide indication of any degradation in well materials. Given the salinity of the formation brines, storage will occur as a mostly separate phase CO_2. Additional monitoring of the CO_2 in the reservoir may be performed to verify sequestration of the injected CO_2. This may involve seismic surveying, reservoir sampling in a monitoring well, or logging in a monitoring well.

Integrated Risk Assessment

A reservoir-scale numerical model was utilized with an integrated assessment framework to address the risk and consequence assessment. The modelling approach is 'integrated' in two senses: (1) modelling of the entire geosystem (including the host formation) overburden with the vadose zone, the shallow sub-surface and the surface (air, soil and water) environments which are the ultimate risk receptors; (2) use of the same underlying modelling framework to assess the fate and transport of injected CO_2 and tracers, risk and consequence assessment and sensor-based monitoring network design. The method was used to simulate sequestration of CO_2 in moderate quantities at the Ohio River Valley CO_2 Storage Project.

An integrated numerical fate and transport model, using the STOMPCO2 code (White and Oostrom, 2006) as the basis, was developed and used for modeling key issues (which include injectivity, seepage and leakage of CO_2, risk and consequence assessment) related to the Mountaineer project. This model differs from other simulations performed for the Mountaineer project (Bacon et al., 2006) in that it includes the entire rock column and does not account for heterogeneity in the injection interval. A typical injection field on the Mountaineer site was used as a test source of potential CO_2 leakage, and leaking CO_2 concentrations and fluxes as the key measures of risk and consequence to humans, animals, biota, property, agriculture, and water resources. A detailed model consisting of 39 lithology layers and 122 distinct hydraulic properties, which represents the Mountaineer field site data from the injection horizons all the way to the surface through the vadose zone, was developed. Simulations were conducted assuming two-dimensional radial symmetry about the injection well by injecting CO_2 in an interval aligned to the vertical boundary of the Rose Run formation.

Table 3-1. Final List of FEPs Identified in the Screening Process

Category	FEP Item	Description	Response
External Factors	Future Human Actions	Drilling activities and mining/other underground activities may penetrate storage reservoirs or containment units	Many coal mines exist in the area, but they are surface mines that penetrate less than 100 m below ground surface and are isolated from the storage reservoir. Drilling activity is possible, but few borings are likely to penetrate the storage reservoir because it contains no hydrocarbon resources or apparent economic value.
CO_2 Storage	CO_2 Storage Pre-Closure	High injection rates and over-pressuring may affect storage reservoirs and containment units	The injection pressure will be kept under fracture gradients (as determined from fracture testing of reservoir and caprocks). Modeling indicates that injection will not overpressurize the storage reservoir.
CO_2 Properties, Interactions, and Transport	CO_2 Properties	CO_2 solubility and aqueous speciation	Storage will not rely on CO_2 dissolution as most CO_2 is anticipated to remain as a supercritical liquid in place due to highly saline formation fluids. These processes have been addressed with geochemical analysis of brine samples from the well and equilibrium models that predict the effect of introducing CO_2 to the formation fluids.
	CO_2 Interactions	CO_2 interaction with fluids or minerals in place	Effects of pressurization on caprocks and formation fluids have been addressed by core testing, reservoir testing, geomechanical analysis, and modeling. All of these methods confirm that the reservoirs are suitable for long-term CO_2 storage. Likewise, these methods were used to determine operational boundaries to prevent processes such as hydrofracturing, mineralogical changes, and induced seismicity.
	CO_2 Transport	-Advection of CO_2 due to injection -Buoyancy-driven flow/migration -Displacement of formation fluids	Movement of the injected CO_2 will be contained in the storage reservoirs as confirmed by injection modeling. The need for a separate monitoring well is being considered for the project, which would be able to monitor migration of injected fluid.
Geosphere	Geology	Reservoir geometry variations and heterogeneity	These features were accounted with stochastic injection simulations to see how they may affect storage over a range of potential conditions such as thickness, permeability variations, and layering.
Boreholes	Drilling and Completion	Durability of well casing and cements	Special cements and tubing are planned for the final well completion, and additional monitoring of the well materials will be built into the project. Injection well design will include interannulus fluid and a surface monitoring system that will automatically detect any damage to the well materials.
	Borehole Seals and Abandonments	Degradation of borehole materials used to abandon the injection well	Acid-resistant cement mixtures were used to complete the proposed injection well. System monitoring will be used to detect any degradation in well materials and well workover may be included to see if well materials altered during the project.
Impacts	System Performance	Loss of containment at injection system	The well lining or injection tubing would be the most likely pathways for loss of containment. The injection well and system will be designed to monitor any indications of loss of containment with pressure monitoring at the well head.

Three different simulation cases were run to assess the leakage of CO_2 into the caprock. Case 1 (base case; rock hydraulic conductivities) was obtained from site characterization. Cases 2 and 3 are modified from Case 1 to cause increasingly leaky cap rock zones. In Case 2, three artificial vertical permeability zones above the host formation were created away from the injection well at locations 16 ft (5 m), 211 ft (64 m) and 579 ft (176 m). The hydraulic conductivities were increased to 20 times the value as in the base case. In Case 3, the artificial hydraulic conductivities from the caprock to the ground surface were randomly increased to 10 times the value as in the base case using a random bit generator. A total injection period of 10 years was conducted for Cases 1 to 3 assuming a well pressure gradient of 0.7 psi/ft and an injection length of 14 ft (4.3 m) from the bottom of the host formation.

An injection rate of 6167 m^3/year, over a 10 year injection period, was predicted by the model. It should be noted that this test injection volume is significantly less than the injection volumes anticipated at field scale implementation of sequestration projects, which may typically inject several thousand cubic meters of CO_2 per day. The supercritical CO_2 extended to around 800 ft (244 m) in the radial direction and penetrated into 20 ft (6 m) into the caprock after the injection stopped. After 80 years of equilibration, the penetration depths into the caprock are about 20 ft (6 m), 180 ft (55 m) and 80 ft (24 m) for Cases 1, 2 and 3, respectively. Case 2 indicates that leakage through a rock containing high permeability zones, such as an abandoned well or fractures, poses the highest risk.

In the next stage of modeling, semi-analytical approaches were used to model the leakage of CO_2 from a typical host formation and its distribution in the various environmental media surrounding the sequestration field. The objective of such modeling is to identify and preliminarily assess the key phenomena that mediate the leakage of CO_2 and the CO_2 fluxes and concentrations in each of the environmental media, which serve as the necessary inputs to the consequence and risk assessment calculations. Accordingly, a fully-screened, perforated injection well in a sequestration field, injecting CO_2 into a 160 m thick sandstone formation bounded by impermeable layers at the top and bottom, is considered to be the base case for this analysis. The injection and formation parameters for the base case, representing a typical gas injection operation, were similar to the base case simulation of Lindeberg (1997) but adapted to the Mountaineer site. Host formation was considered to be the Rose Run sandstone with thicknesses of 50 to 100 ft (15 to 30 m), with a nominal permeability of 1 to 50 mD and a porosity of 10%.

The simulation results indicate that, at the relatively low injection volumes planned for pilot-scale demonstration at this site, the risks involved are minor to negligible, owing to a thick, low permeability caprock and overburden zones. Such integrated modelling approaches coupled with risk and consequence assessment modelling are valuable to project implementation, permitting, monitoring and site closure.

3.6 CO_2 Capture and Separation

An essential first step for sequestering CO_2 is capturing it from the point sources where it is produced and preparing the captured CO_2 for pipeline transmission and injection. While there are commercially available technologies for capturing CO_2, this is an area where extensive research is still taking place.

A number of technical issues must be considered when assessing the applicability of a CO_2 capture technology to a power plant (or any other CO_2 point source). Several major considerations are:

- Process Configuration – This relates to the way in which the capture unit will be integrated into the existing process scheme. On the surface, this would seem to require simply the addition of a scrubber situated immediately before the stack. However, plant modifications to accommodate an additional scrubber may well entail numerous and complex changes to the steam cycle of the plant. Retrofitting an existing power plant also requires consideration for space to construct additional equipment in an optimized fashion. Also, before a retrofit can be considered the remaining useful life of the plant must be determined. However, as it is common practice to extend the lifespan of power plants whenever possible, retrofits are usually considered more practical than constructing a new plant that is CO_2 "capture ready."

- Quantity of Gas to be Treated – Large CO_2 point sources emit large quantities (i.e., at least 100 ktonne/year) of CO_2. In normal PC plants the CO_2 is present in the flue gas is dilute (<15%), the quantity of gas to be treated is much larger than the volume of CO_2. For this reason, the CO_2 capture equipment must be sized to accommodate the total quantity of flue gas. An alternative conversion of the boil for oxycombustion may require less gas processing because the resulting flue gas stream is several times richer in CO_2 content.
- Quality of Gas to be Treated – This consideration relates the flue gas composition, including water saturation, ash content, temperature and pressure. Quality of the feed gas may affect the performance of the capture CO_2 system unless adjustments are made. For example, certain impurities may need to be removed to avoid adverse impacts on performance, or to enable the captured CO_2 to meet pipeline and sequestration specifications.
- Energy Requirements – In general, CO_2 capture requires appreciable amounts of energy for unit operations that may include solvent regeneration, fluid transport, duct blowers, compression, etc. The large amount of energy that is used can substantially reduce the economic attractiveness of the capture process. One measure of the so called "energy penalty" for power plants is often calculated as $(MW_{ref} - MW_{cap})/MW_{ref} \times 100\%$, where MW_{ref} is the electrical power output (in megawatts) of a reference plant without CO_2 capture, and MW_{cap} is the electrical power output of the same plant with CO_2 capture. If the fuel used by the plant with CO_2 capture differs from that for the reference plant, then the energy penalty must be calculated on the basis of efficiency. Hence, the energy penalty is energy that, in the absence of CO_2 capture, would have gone to the electrical grid to meet consumer demand and produce revenue for the plant.

Post-combustion Capture of CO_2

In post-combustion capture, CO_2 is separated from the flue gas produced by the combustion process. Post-combustion CO_2 capture may be applied to treat flue gases resulting from coal, as well as gas- or oil-fired steam-cycle power generating units, gas turbines, or natural gas combined cycle (NGCC) units. Each of these power generation units combust fossil fuels, and therefore produce flue gases containing CO_2. These flue gases may be treated to remove impurities can adversely affect CO_2 capture, such as NO_x, SO_2, and particulate matter, prior to separation of the CO_2.

The CO_2 content and composition of the flue gases depend on the type of fossil fuel being combusted (i.e., coal, oil, or natural gas), as well as the type of power generation process being employed (i.e., gas turbine or NGCC vs. gas-fired steam cycle). Power plant flue gases are relatively dilute in CO_2, as they contain approximately 13 to 15% CO_2 by volume for coal combustion and less than this amount for other fossil fuels. These flue gases typically leave the stack at approximately atmospheric pressure. Hence, the partial pressures of CO_2 in power plant flue gases are low (e.g., 13 to 15 kPa). Since the majority of the flue gas is inert, very large amounts of gas need to be processed to recover a relatively small amount of

CO_2. For example, a large 1,300 MW plant like Mountaineer may correspond to total flue gas flowrates of roughly 8,000,000 m^3/h at full load. Compressing these quantities of flue gas to produce higher CO_2 partial pressures would be very energy-intensive and costly, and therefore is not done.

Of the commercially-available CO_2 capture technologies, amine-based systems are thought to be the most technically feasible option for CO_2 capture from coal-fired power plants in the near term. This is the only commercially-available technology that appears suitable for achieving more than 90% CO_2 removal and producing pipeline quality CO_2 product from high-volume, low-pressure, dilute, chemically oxidizing feed gases. However, other technologies that utilize solvent absorption are being testes at the pilot-scale. Systems that involve aqueous ammonia as the CO_2-absorbing medium are among the most actively tested.

Flue Gas Impurities

The primary feed gas impurities of concern for amine scrubbing systems are SO_x, NO_2, and particulate matter. Thus, amine scrubbers for post-combustion CO_2 capture would be located downstream of existing air pollution control equipment, which is designed to remove these impurities. Although power plant flue gases can contain high concentrations of NO_x, this typically does not pose a problem in amine absorption systems because most (greater than 90%) is present as NO rather than NO_2. Nevertheless, a majority of the power generating units in southeastern Ohio are equipped with NO_x control technologies to meet environmental regulations. Particulate matter (fly ash) resulting from the combustion of coal also can result in problems for amine absorption systems. However, plants burning these fuels are generally already equipped with particulate control devices to remove particulate matter from the flue gas.

SO_2 removal is probably the most important flue gas pretreatment consideration for applying amine scrubbing to capture CO_2 from high-sulfur coal-burning power plants. Eastern bituminous coals generally have higher sulfur contents than western subbituminous coals. Many coal-fired units in the region are equipped with flue gas desulfurization equipment. Currently, operating scrubbers are generally designed to achieve 90 to 95% SO_2 removal, and new limestone forced oxidation (LSFO) and magnesium enhanced lime (MEL) wet scrubbers are designed to achieve 98% SO_2 removal. However, for flue gases containing more than 500 parts per million (ppm) of SO_2, 98% removal is not sufficient to achieve the less than 10 ppm of SO_2 that is recommended for amine scrubbing systems. Medium-to-high sulfur bituminous coals will produce flue gases with SO_2 concentrations that are much higher than 500 ppm. Even low-sulfur coals and fuel oils produce much more than 10 ppm of SO_2. Therefore, coal and oil-fired plants in southeastern Ohio that are not currently equipped with SO_2 scrubbers would require installation of such scrubbers before an amine system for CO_2 capture could be installed. In addition, many units currently equipped with SO_2 scrubbers would require modifications in order to attain 10 ppm of SO_2 prior to the installation of an amine system. Sulfur dioxide and sulfur trioxide (SO_3) must also be maintained at low concentrations to avoid heat stable salt formation in the amine system.

Potential Options for Future Power Plant Designs

Lower cost CO_2 capture may be attained in several ways: integration of CO_2 capture with new power plant design; oxyfuel combustion; and pre-combustion capture. These lower cost options are described below.

Amine scrubbing systems installed on new power plants have lower energy penalties than those retrofitted on existing plants because the energy and steam requirements of the amine scrubber can be more efficiently integrated into the design of the new plant. Because of this disparity in energy penalties, it may superficially appear that power plant owners in southeastern Ohio would choose to build new plants rather than retrofit existing ones with CO_2 capture systems, in consideration of the average vintage (1964) of bituminous coal-fired plants in the region. However, billions of dollars are currently being spent to install SO_2 and NO_x emission controls on many of these older plants. Hence, if CO_2 capture and sequestration were required in the near-term, it is likely that a number of these plants would be candidates for amine scrubber retrofits.

Oxyfuel combustion, or O_2/CO_2 recycle combustion, has been proposed and studied as a possible way to produce sequestration-ready CO_2 streams from combustion in coal, oil, and gas-fired boilers (Dillon et al., 2004) and gas turbines (Kvamsdal et al., 2004). In the oxyfuel configuration, an air separation unit (ASU) produces relatively pure (i.e., >95% v/v) oxygen from air; this oxygen is fed to the combustor in place of the normal combustion air. Fossil fuel combustion in pure O_2 results in very high flame temperatures that would not be compatible with the design of conventional boilers and gas turbines. Therefore, in oxyfuel combustion processes, the O_2 is mixed with a recycled CO_2 (dry oxyfuel combustion) or CO_2/H_2O (wet oxyfuel combustion) stream to approximate the combustion characteristics of air (O_2/N_2). CO_2 and H_2O absorb and emit thermal radiation, whereas N_2 does not. Therefore, the substitution of CO_2 and H_2O for N_2 also alters the heat transfer characteristics of the combustion gases. A mixture of CO_2 and O_2 containing about three moles of CO_2 per mole of O_2 is necessary to approximate the flame temperatures and heat transfer characteristics produced by air in a conventional PC boiler.

Pre-combustion capture is considered to be the leading candidate for capturing CO_2 from power plants. This configuration typically involves the gasification of coal or the partial oxidation or steam reforming of natural gas to produce a synthesis gas (syngas) rich in CO and H_2, followed by a shift reaction to convert the CO to CO_2. The CO_2 is then removed from the syngas, and the remaining H_2 is combusted in a combined cycle unit, including both a gas turbine and a steam turbine, to produce electricity.

Integrated gasification combined cycle (IGCC) plants permit pre-combustion CO_2 capture with coal as the feedstock. Gasification can be either air-blown or oxygen-blown. In the latter case, a cryogenic ASU is used to produce relatively pure O_2, which is fed to the gasifier. Oxygen-blown gasification is better suited for CO_2 capture than air-blown gasification, and is the favored process in most studies of IGCC with pre-combustion CO_2 capture for sequestration (Smith et al., 2002).

In addition to these leading candidate configurations for capturing CO_2 from power plants, several other novel concepts have recently received attention. Innovative power generation cycles such as the MATIANT cycle and the Graz cycle have been proposed (Gupta et al., 2003). Also, considerable attention has been given to the concept of chemical looping combustion (CLC). Unlike conventional combustion processes, CLC processes never permit the fuel to mix with the combustion air. Rather, a metal oxide is circulated between an air reactor, where it is oxidized by reaction with oxygen contained in air, and a fuel reactor, where it is reduced by reaction with a fuel gas to form CO_2 and water. However, CLC technology is yet in a very early stage of development, and it is presumed that a pilot-scale demonstration will not be feasible for at least several more years.

CO_2 Capture in a Slipstream to Evaluate Implementation Issues at a Power Plant

While the technology to capture CO_2 from a gas mixture is well known, as are the technologies to transport CO_2 under high pressure and inject the CO_2 in geologic formations (e.g., in enhanced oil recovery [EOR]), the full integration of these processes at a large power plant remains to be demonstrated. To evaluate each of the main process components, a slipstream bypass from the main flue gas stack was investigated for the Mountaineer Power Plant site. Preliminary feasibility and design for a small scale (up to 50 tonne/d CO_2) capture system was completed. The design includes the best available capture technology with compression, pipeline transport, and deep-well injection to collect data that will be useful for an eventual full-scale system in southeastern Ohio.

Design Concept

A suitable design basis could consist of a hypothetical pilot-scale system to capture 50 tonnes per day of CO_2 (0.87 MMscfd CO_2 flow) from a 5.6 dry MMscfd (6.4 wet MMscfd) flue gas stream. The CO_2 recovered from the pilot-scale amine-based capture unit will be compressed from roughly atmospheric pressure to 2,000 psi for injection into the AEP No. 1 test borehole. Furthermore, the pilot-scale capture unit could be skid-mounted to facilitate multiple short-term (6 months to 1 year) demonstrations. Figure 3-11 shows a example process flow diagram for the pilot unit and compression system. The following subsections describe the necessary equipment.

Upstream Processing

The flue gas will require upstream processing before feeding into the separation unit. The upstream processing will include an inlet knockout, a flue gas blower, a packaged caustic scrubber system, a final knockout vessel, and ductwork to and from the pilot unit. The flue gas slipstream will originate at the flue gas desulfurization (FGD) outlet (Figure 3-12). The flue gas is assumed to be saturated at 125°F and atmospheric pressure. This yields a wet gas flowrate of nearly 5,000 actual cubic feet per minute (acfm) (4,400 standard cubic feet per minute [scfm]). The flue gas will travel through a small duct approximately 1,000 ft to the pilot unit skid, where an inlet knockout will protect the flue gas blower. A similar duct will return the flue gas from the amine absorber overheads to the electrostatic precipitator inlet. The ductwork will require low-point drains. The flue gas blower will provide a 2.25 psi pressure increase, which corresponds to approximately 80 horsepower. The caustic scrubber will remove additional SO_2 from the flue gas to below 10 ppm. The caustic scrubber will also guard against particulates entering the amine unit. In order to avoid absorbing CO_2 into the caustic solution, the scrubber will operate near pH 6 and circulate dilute caustic. The scrubber system will include the scrubber, the recirculation pump, a chemical feed system, a water makeup system, and automation. Caustic scrubbers typically have mist eliminators to prevent liquid carryover.

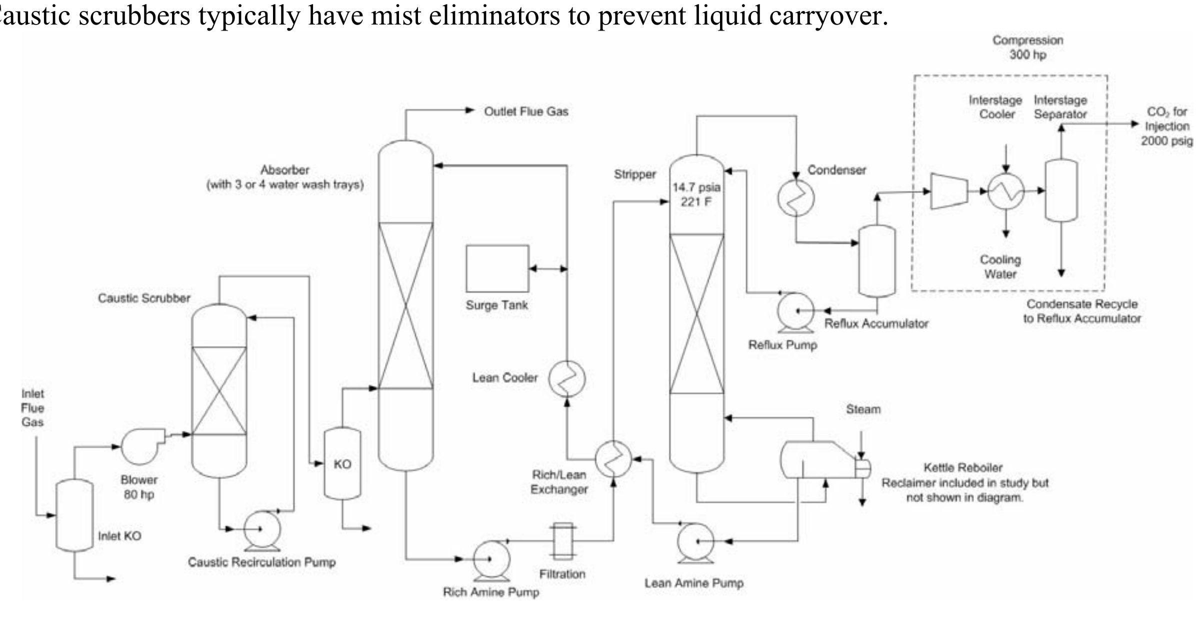

Figure 3-11. Example Process Flow Diagram for a Potential CO_2 Capture Pilot Unit at the Mountaineer Power Plant

Base Amine Unit

The base amine unit consists of an absorber, regenerator, associated process heat exchangers and pumps, and filtration equipment as necessary. Flue gas from the upstream processing equipment flows vertically upward through the absorber countercurrent to the amine-based sorbent to remove CO_2. The scrubbed gases may be washed and vented to the atmosphere or returned to the flue gas system as desired. The latter option is slightly more complex than the former option due to the return air duct and connection at the ducting area. The CO_2-rich amine stream leaves the absorber and passes through a heat exchanger; then it is further heated in a reboiler using low-pressure steam. The absorption reactions are reversed with heat supplied by stripping steam generated in the reboiler so that water vapor and CO_2 gas exit the top of the stripper. The power plant will provide steam. The hot, lean-CO_2 stream is returned to the heat exchanger, where it is cooled and sent back to the absorbers. A reflux system is used on the stripper overhead stream to condense the steam and separate it from the acid gas. The acid gases then proceed to the compression stage of the process. Some fresh solvent is added to make up for the losses incurred in the process. A filtration step may be needed to minimize accumulation of solids and other contaminants in the amine solution; a reclaimer will be used to remove high boiling degradation products and sludge.

The general amine flow scheme described above should be applicable to a variety of solvents (e.g., conventional mono-ethanol amine (MEA), advanced amine solvents, mixtures of solvents, etc.).

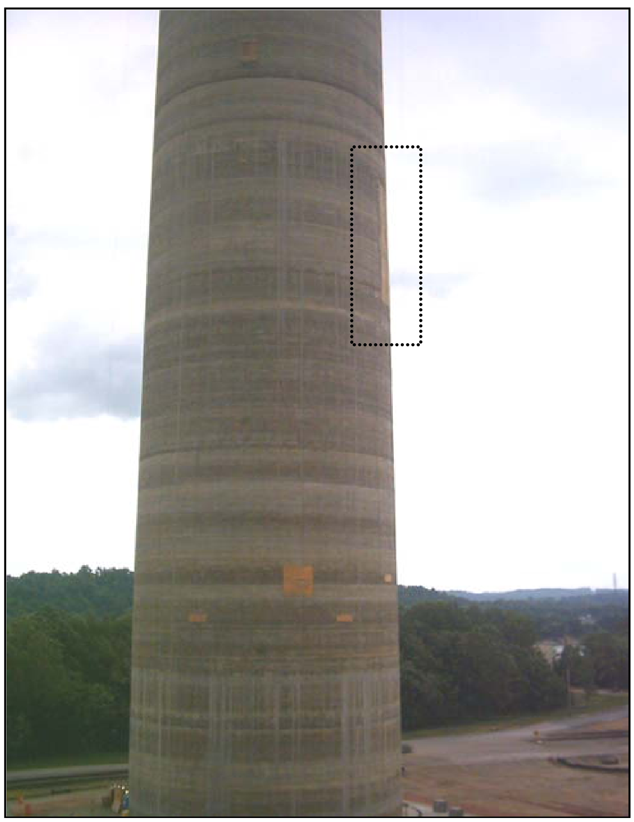

Figure 3-12. Rectangle Shows Outlet Port on FGD Stack Where a Flue Gas Slipstream Could Originate

Compression

The CO_2 gas from the pilot unit regenerator should be compressed to approximately 2000 psi for efficient pipeline transport across the plant and downhole injection. As assumed in the Design Concept, the gas stream to the compression train contains about 0.87 MMscfd of CO_2 and is saturated with water at reflux conditions. Based on a review of the literature, four stages of reciprocating compression will be required to achieve the final pressure of 2,000 psi. Also, each stage will have a maximum compression ratio of 3.4 and discharge temperature limit of 300 °F, where it was assumed that the gas would be cooled with interstage water coolers to approximately 104 °F and any condensed liquid would be separated from the gas stream as necessary. Controlling the gas temperature to within the smallest range possible is a practical approximation of isothermal compression, and therefore, will result in the lowest energy pathway from ambient conditions to the desired pressure.

Waste Generation and Handling

Caustic waste tanks, amine makeup tanks, amine waste tanks, piping of the CO_2 from the compressor outlet across the site to the injection well, and processing for waste caustic and waste amine would need to be designed. However, the costs for waste handling equipment are thought to be minor in comparison with the other capital costs for the pilot-scale capture unit.

3.7 Monitoring CO_2 Sequestration

This section provides an overview of monitoring technologies as they apply to geologic CO_2 storage in the Ohio River Valley. CO_2 monitoring technologies have advanced over the past 10 years as geologic sequestration has progressed from a research topic to field applications. Many of the technologies have been adopted from oil-field, environmental, or deep-well injection applications. However, some monitoring techniques are new methods designed to take advantage of the distinct properties of supercritical CO_2. Several major project sites have included monitoring as an emphasis: Sleipner, Norway; Weyburn, Canada; In Salah, Algeria; Frio Formation, Texas; and Nagaoka, Japan.

The objective of monitoring is to assess the status of CO_2 from the capture facility to the storage reservoir, including capture of CO_2 at the source, transport to the injection facility, injection in a deep well, and storage of the injected CO_2 in deep geologic reservoirs. In assessing monitoring technologies, it is useful to group methods into categories related to capture/injection system, leakage, injected CO_2, and operational safety (Figure 3-13). Monitoring methods associated with these goals cover a broad range of technology. Much of the monitoring related to the capture, transport, and injection system may be borrowed from established, industrial practices. However, assessing the migration and alterations of the injected fluid is more developmental. Additional research is necessary to develop monitoring, mitigation, and verification systems that satisfy a variety of stakeholders. The paramount issue is to verify safe, secure, and economic long-term storage.

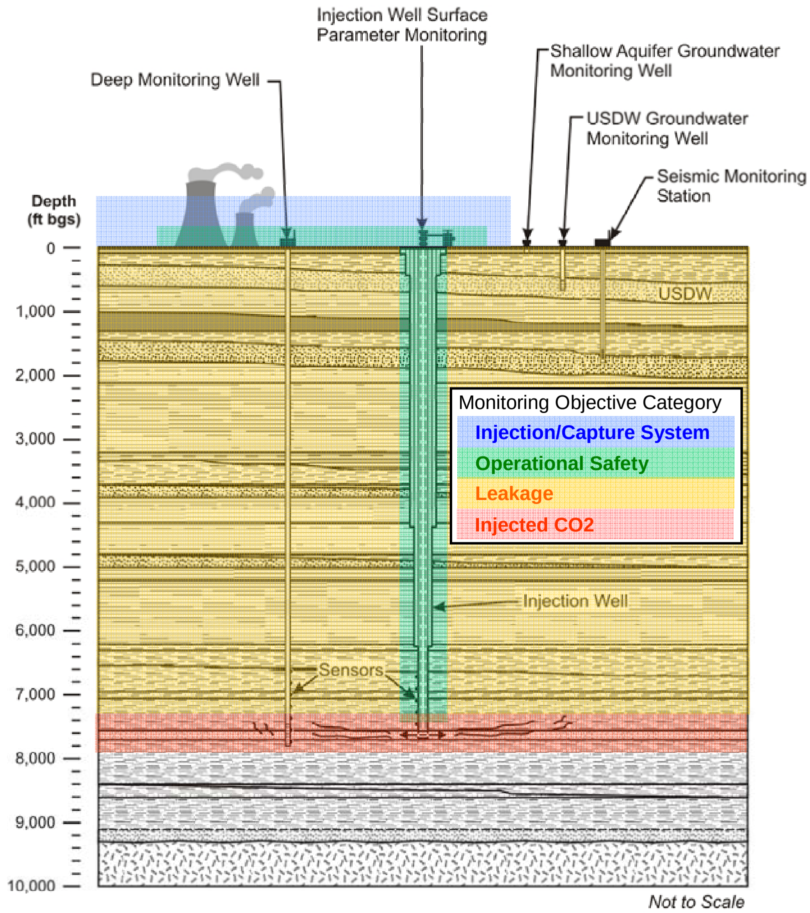

Figure 3-13. Diagram Illustrating Monitoring Objective Categories for CO_2 Storage Site

Capture/Injection System Monitoring

System monitoring generally refers to the operational parameters associated with capture, transport, and injection of CO_2. Essentially, this monitoring is required for handling CO_2 at the surface. To determine the efficiency of the capture method, factors such as flowrates, capture media turnover rates, and power consumption would be measured. Analysis of the composition of the injectate is necessary because even low concentrations of water create acidic conditions in the compressed pipeline and can lead to corrosion problems. In addition, impurities such as SO_x and NO_x can exacerbate the corrosive conditions. Pipeline monitoring of the captured gas is also an important category to ensure safe transport. Sampling and analysis of the injectate is necessary to demonstrate composition of the injected gas. Pressure, flow, and temperature measurements at the injection well are also part of system monitoring. Measurements taken in system monitoring form the basis of other monitoring parameters. Many of the system monitoring parameters can be tracked as indicators of changes in reservoir quality, degradation of well materials, and other processes.

Monitoring CO_2 Injectate

Tracking the movement and alteration of the injected CO_2 in the subsurface represents one of the more challenging aspects of a monitoring program. This monitoring is necessary to ensure long-term storage and verify location of the CO_2. Geologic heterogeneity makes it difficult to estimate the transport pathway of CO_2 once injected. In addition, there are challenges to obtaining a representative sample from deep wells due to the phase behavior of CO_2. For these reasons, indirect methods (such as geophysical and well logging) that can detect the contrast of CO_2 against native brines are attractive. The category may include monitoring in the reservoir itself or the surrounding caprock.

Monitoring Leakage

Monitoring leakage is considered an important aspect of monitoring to demonstrate geological storage. Because supercritical CO_2 will be buoyant, most leakage monitoring is focused on containment layers, portions of the updip storage reservoir, groundwater aquifers, and surface. A diligent assessment of anthropogenic pathways such as active and abandoned wells is the first step in evaluating leakage. Underground Injection Control (UIC) programs also require monitoring and assessment of injection well mechanical integrity. Monitoring leakage in deeper layers relies on deep wells, wireline, or geophysical methods. The deeper a reservoir, the less likely to allow for flux to the surface or shallow groundwater. Surface flux is probably more realistic in large, shallow reservoirs with more immediate pathways to the surface. If CO_2 does reach the surface, it may be difficult to reliably quantify flux given the large number of factors which could affect measurements. As such, it may be more appropriate to monitor indicators of surface flux before extensive investments to quantify flux. This category may also be considered as part of the safety monitoring for the injection facility.

Operational Safety Monitoring

Several levels of safety monitoring may be integrated into a storage project. Fortunately, most safety monitoring technology is fairly mature and reliable. Safety monitoring may be used with capture, transport, and injection to ensure that no accidental release occurs. Likewise, many injection parameters may be monitored with automated systems to ensure integrity of the monitoring well and immediate storage reservoir. Finally, methods may be used to demonstrate stable conditions of the reservoir and surroundings, such as passive seismic monitoring and well logging.

Technology Survey Overview

The technologies may be divided into categories for injection systems, fluid-phase monitoring, gas-phase (CO_2) monitoring, wireline or downwell methods, and other geophysical methods:

- **Injection System** − Monitoring the injection system refers to measurements made at the CO_2 pipeline, wellhead, casing, injection tubing, and other pertinent apparatus. This category is generally the most straightforward and prevalent type of monitoring performed at deep injection wells. Measurements of various parameters at the injection well are made at nearly all injection well sites. Much of this monitoring is prescribed in UIC regulation or considered useful in tracking EOR effectiveness. System monitoring practices provide information that may be of assistance in evaluating any weaknesses or failure in the well casing, cement job, injection machinery, and/or injection interval.
- **Fluid-phase** − This category includes monitoring water and brine sources for the presence of injected CO_2, displaced formation fluids, or indicators of these. The general process includes obtaining background readings and comparing them to periodic readings collected during and after injection. Fluid phase options include reservoir brine sampling, shallow groundwater or surface water sampling, and tracer tests. All of these technologies rely on tracking some indicator parameters of CO_2 migration in the subsurface through direct fluid sampling.

- **Gas-phase** − This category includes monitoring of storage reservoir or soil-gas for the presence of injected CO_2, displaced formation gasses, or indicators of these. Background readings are collected and compared to periodic readings collected during and after injection. Gas phase monitoring may include sampling of the injected CO_2 from a deep well, monitoring tracer chemicals in the gas (introduced or natural isotopes), shallow soil gas sampling, and surface flux measurements.
- **Wireline or Downwell** − Well logs are one of the most common methods for evaluating deep geologic formations. Logs are collected by lowering an instrument into a well and taking a profile of one or more physical properties along the length of the well. Many different logs are available for measuring a variety of parameters, including condition of the well, composition of pore fluids, and mineralogy of formations. Logs such as temperature, noise, casing integrity, and radioactive tracer logs are most useful for checking the condition of the well and ensuring that the well itself does not provide a leakage pathway for injected CO_2. These logs have an extensive history of downwell use and provide reasonably good data, though the resolution available might not be sufficient to detect small rates of seepage through microcracks. Other logs, such as neutron, dipolesonic imager (DSI), and reservoir saturation tools (RSTs), look into formations around the well and log parameters such as pore fluid composition, extent and formation mineralogy.
- **Geophysical** − Geophysical techniques can be applicable to monitoring of CO_2 storage. However, it should be noted that the effectiveness of some methods depends on CO_2 saturation, resolution of the technique, and rock properties. Geophysical monitoring options include four-dimensional seismic surveys, cross-well seismic surveys, vertical seismic profiling, microseismic/passive seismic monitoring stations, crosswell electric resistive tomography, crosswell magnetic tomography, and remote sensing methods.

Monitoring Considerations

As described in the previous sections, there is a wide range of monitoring options for CO_2 capture and storage. Table 3-2 summarizes monitoring methods used at major CO_2 storage projects to date. As shown, various technologies were selected based on the scale of the project, geologic setting, and general setting. As shown, application of all of these methods at a single site is technically impractical, repetitive, and/or expensive. In addition, many of the technologies may not work in southeastern Ohio given its setting. Therefore, a more manageable monitoring strategy can be optimized for local conditions. In the Ohio River Valley region, a program may include the following components:

Capture/Injection System – Performance monitoring of the system is considered an important aspect of the project and should provide critical information to scale up CO_2 capture technologies. In addition, transport and injection of the CO_2 are essential operational processes. Therefore, a supervisory control and data acquisition (SCADA) monitoring system is recommended for both pipeline and injection well measurements. This system includes parameters such as flow, temperature, and pressure that are essential to monitor system integrity and performance. For the injection well, monitoring prescribed by UIC regulations will be necessary. These measurements will form the foundation of the monitoring program.

Injected CO_2 – Assessing the migration and nature of the injected CO_2 may be challenging at sites in the region due to the deep target reservoirs and lack of other wells that penetrate the storage reservoirs. A comprehensive inventory of the CO_2 injectate in the deep storage reservoir is probably not feasible at many sites. Therefore, a less detailed analysis of the injected CO_2 using indirect geophysical methods and occasional sampling is recommended. Crosswell seismic surveys and vertical seismic profile methods appear to offer the most promise for determining the extent of the injected CO_2. Limited fluid and/or gas phase monitoring may be accomplished with monitoring wells, but a network of wells is probably not feasible at most sites.

Leakage − The geologic setting for much of the Ohio River Valley indicates a very low probability for leakage from the available storage reservoirs. Leakage along the well bore is considered the main pathway for leakage and much of the leakage monitoring will be integrated with system monitoring.

Operational Safety − System safety should be the main objective of the capture and storage project. For a continuous capture and injection design, the materials must be adequate to resist the corrosive properties of CO_2 and extended operation. In addition, many of the system parameters may be analyzed to evaluate CO_2 migration, leakage, and borehole integrity.

Table 3-2. List of Monitoring Methods Performed at Major CO_2 Storage Projects

Category	Method/Description	Weyburn	Frio	In Salah	Sleipner	Nagaoka
Setting	Location	Calgary	Texas	Algeria	N. Sea	Japan
	Reservoir	Carbonate	Frio SS	Carb. SS	Utsira SS	Haizume SS
	Geologic Setting	Williston Basin	Gulf Coast	Krechba Dome	North Sea Shelf	Plio.-Pleist. Sands
	Depth	3,300	5,000	6,500	3,000	3,600
	Injection Volume (metric ton)	>6,000,000	1,600	(>1,000,000)	>7,000,000	10,452
Inj. System	Injection Well Measurements	√	√	√	√	√
Fluid-phase	Shallow GW Monitoring		√			
	Surface water sampling		√			
	Reservoir Sampling	√	√	√		
Gas-Phase	Monitoring injectate	√	√	√	√	√
	Tracers in injectate	√	√	√		
	Shallow soil-gas monitoring	√	√			
	Lower atmospheric mon.		√			
Wireline or Down-well	Traditional Wireline	√	√	√		√
	RST		√			
	DSI		√			
Other Geophysical methods	4-D Seismic	√		√	√	√
	VSP	√	√			
	Microseismic	√				√
	Crosswell Seismic Tomography	√	√			√
	ERT/EMT		√			
Remote Sensing	Airborne gas					
	Aeromagnetics/Gravity			√	√	
	Hyperspectral imagery					
	Surface deformation/tilt			√	√	

Section 4.0: CONCLUSIONS AND RECOMMENDATIONS

4.1 Storage Reservoir Evaluation

This section summarizes potential storage reservoirs in the Ohio River Valley based on regional investigation and exploratory efforts. Based on the research, most of the deep rock formations typically encountered in the area are considered containment layers. These formations appeared to be dense dolomite, siltstone, or shale that would prevent upward migration of fluids. In general, these formations were several thousand feet thick and had very low porosity and permeability that would prevent migration of any injected fluid. These rocks form an excellent framework for geologic storage of CO_2 because they are thick, extensive, and stable with few major faults.

From a reservoir standpoint, it is difficult to generalize the area. Many rock formations transition to different rock types in this portion of the Appalachian basin. In the AEP No. 1 well, the Rose Run sandstone and the Copper Ridge "B-zone" showed the most potential for injection. The Rose Run sandstone was identified as a potential injection reservoir in borings in the region. The formation has a total thickness of 50 to 200 ft and is found at depths of over 2,500 to 11,000 ft. In the AEP No. 1 test well, the Rose Run was 116 ft thick at a depth of 7,750 ft. However, it appears that the effective sandstone interval suitable for CO_2 storage is less than the bulk thickness. Oil and gas production in Rose Run is more limited to central Ohio, and few old wells that may be conduits to the surface penetrate the formation.

The Copper Ridge "B-zone" was also noted as a potential reservoir in several borings in the test well. The zone consisted of several intervals of very high permeability and porosity within the upper Copper Ridge Dolomite. The "B-zone" was correlated to other borings in the region and appears to be a continuous unit. Wireline logs and rock cuttings suggest that the permeable intervals may be correlated with vugular zones or quartz. A Basal sandstone/Mt. Simon sandstone unit was generally not suitable for injection in the region. The unit appears to transition to a less permeable formation in eastern Ohio. This rock formation may have storage potential in other portions of the study area (i.e., north or west of the AEP No. 1 well).

Depleted oil and gas fields that may offer storage opportunities include the Oriskany-Newburg sandstones, Devonian Black shales, and the Berea sandstone. Most of these fields were gas producers, so the opportunities for EOR are limited. There is not much precedent for EOR in the Ohio River Valley region that would substantiate CO_2 injection.

Of the oil and gas fields in the study area, Oriskany-Newburg fields have the most suitable depth for CO_2 storage. Devonian Black shales may be storage targets; however, there may be challenges to injection in shales. The Berea sandstone has marginal depth for CO_2 storage as a supercritical fluid in much of the area. Both Devonian Black shales and Berea sandstone are penetrated by thousands of oil and gas wells, many of which have questionable well-plugs. Consequently, leakage through abandoned wells may be an appreciable challenge to CO_2 storage in these formations.

From a conceptual standpoint, the reservoirs are present as isolated layers within the overall thickness of generally low permeability containment rock. Trapping mechanisms consist of mostly lithologic trends where the reservoirs diminish in the subsurface. No extensive faulting or fracturing is present in the study area; although, some faulting may be present toward the Rome Trough. Containment layers are diverse and extensive. This suggests an excellent setting for long-term storage of CO_2.

4.2 Guidance for CO_2 Storage Opportunities

This section provides general guidance for CO_2 storage opportunities in the Ohio River Valley region. Much of the information presented is based on the Mountaineer exploratory test well and the regional characterization wells. The goal of this guidance is to provide practical recommendations in the areas of geologic framework, injection well drilling and characterization, and regional characterization.

Geologic Framework

- The geologic setting in the Ohio River Valley is suitable for geologic sequestration. Thick, extensive sequences of sedimentary rocks form stable regional basins, which provide suitable targets for CO_2 storage.
- Much of the information necessary for evaluation of the geologic framework exists in various research publications. However, there are large gaps in data coverage regarding the deeper rocks. There is still a fair degree of uncertainty regarding deeper formations because few deep wells have been drilled to these formations.
- There may be some faulting associated with the Rome Trough, which parallels the Ohio River southeast of the study area. However, this is an inactive feature. The area has a low seismic hazard risk rating, and injection is unlikely to cause seismic activity unless injection occurs in a faulted interval.
- The Rose Run sandstone and Copper Ridge dolomite were identified as the main storage reservoir targets in the area. The Basal sandstone transitions to a low permeability unit in the area and appears to be a poor storage target in the area.
- Containment is excellent in the area due to thick, extensive, and diverse caprock layers.
- Overall, it appears that opportunities for enhanced coal bed methane recovery are more promising in northern West Virginia and southwest Pennsylvania. Development of this option would require additional investigation and infrastructure.

Injection Well Drilling and Characterization

Drilling

- Existing oil and gas well drilling technology is sufficient for construction of a injection well, but wells will require specialized construction specifications and materials to ensure long-term durability and containment.
- Drilling at existing power plant sites is feasible, but may require some additional measures to ensure safety of the plant and its personnel.
- Characterization such as rock coring and brine sampling adds time and expense to the drilling effort, but provides tangible data necessary to design a storage project.

Wireline Logging

- A full suite of wireline logging methods is available for delineating reservoirs and caprocks. Traditional logging methods (neutron, gamma, density, caliper) are useful for determining lithology, but the CMR tool was very effective in assessing permeability of potential reservoir zones.

- Additional analysis beyond typical oil and gas methods was necessary to explore CO_2 storage reservoirs and caprocks.
- Wireline methods generally confirmed information gathered from core testing and reservoir tests.

Seismic Surveying

- The seismic survey was mainly useful in proving that no major faults or fracture zones exist in the injection area. A survey may show geologic structures, but rock formations are fairly predictable and consistent in the region.
- Seismic survey may be necessary to fulfill U.S. EPA UIC regulations.
- Seismic monitoring (four-dimensional or vertical seismic profiling) of the CO_2 injection front may not be possible due to the typical rock properties in the region. Rocks are very dense and lithified such that seismic velocities are very high and may not relate the density contrast of the CO_2 in the pore space.

Rock Core Collection and Testing

- Rock core sampling and testing provides tangible evidence of reservoirs and caprocks that can be utilized for extensive testing to demonstrate storage concepts.
- Wireline rotary sidewall coring methods may be used to reduce the expense associated with full coring.

Reservoir Testing

- Reservoir tests are the best way to assess actual injection capacity in a target reservoir.
- The information gathered from reservoir testing is important for design of the hydraulic fracturing program, injection well design, and injection parameters.
- A step-wise testing approach may be useful to evaluate multiple injection targets.

Section 5.0: REFERENCES

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