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BEST PRACTICES for:

Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations

First Edition

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

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Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations

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List of Acronyms and Abbreviations

Acronym/Abbreviation	Definition
2-D	Two-Dimensional
3-D	Three-Dimensional
4-D	Four-Dimensional
AC	Accumulation Chamber
ADRS	Amargosa Desert Research Site
ANSI	American National Standards Institute
AoR	Area of Review
API	American Petroleum Institute
Ar	Argon
ARI	Advanced Resources International
ASTM	American Standard Test Method
BEG	Bureau of Economic Geology
BGS	British Geological Survey
Big Sky	Big Sky Carbon Sequestration Partnership
BLM	Bureau of Land Management
BNL	Brookhaven National Laboratory
C	Carbon
Ca	Calcium
CASSM	Continuous Active Seismic Source Monitoring
CBL	Cement Bond Log
CBM	Coalbed Methane
CCS	Carbon Capture and Storage
CCX	Chicago Climate Exchange
CES	Clean Energy Systems
CGM	Craig-Geffen-Morse Water Flooding Model
CH_4	Methane
CIR	Color Infrared
Cl	Chlorine
CL	Cathodoluminescense
cm	centimeter(s)
CMG	Computer Modeling Group
CO_2	Carbon Dioxide
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies
CRT	Cathode Ray Tube
CSLF	Carbon Sequestration Leadership Forum
DIAL	Differential Absorption LIDAR
DOE	U.S. Department of Energy
DTPS	Distributed Thermal Perturbation Sensor
EC	Eddy Covariance
EDS	Energy Dispersive X-Ray Spectroscopy
ECBM	Enhanced Coalbed Methane
EELS	Electron Energy Loss Spectroscopy
EMIT	Electromagnetic Induction Tomography
EOR	Enhanced Oil Recovery
EPMA	Electron Probe Microanalyzer
EM	Electromagnetic
EPA	U.S. Environmental Protection Agency
ERT	Electrical Resistivity Tomography

Acronym/Abbreviation	Definition
ES&H	Environmental, Safety, and Health
ft	Feet
FE	DOE's Office of Fossil Energy
FLOTRAN	Flow and Transport Simulator
g	Gram(s)
GFZ	GeoForschungsZentrum
GHG	Greenhouse Gas(es)
GIS	Geographic Information System
GPR	Ground Penetrating Radar
GPS	Global Positioning System
GS	Geological Storage/Sequestration
H/H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
He	Helium
HC	Hydrocarbon
HCl	Hydrogen Chloride
HVAC	Heating, Ventilation & Air Conditioning
Hz	Hertz
IEA GHG	IEA Greenhouse Gas Programme
in	Inch(es)
IR	Infrared
IRGA	Infrared Gas Analyzer
IEA	International Energy Agency
IOGCC	Interstate Oil & Gas Compact Commission
IP	Induced Polarization
ISO	International Organization for Standardization
IPCC	Intergovernmental Panel on Climate Change
km	Kilometer(s)
Kr	Krypton
KHz	Kilohertz
LANL	Los Alamos National Laboratory
LBNL	Lawrence Berkeley National Laboratory
LCD	Liquid Crystal Display
LEERT	Long Electrode Electrical Resistance Tomography
LIDAR	Light Detection and Ranging
LLNL	Lawrence Livermore National Laboratory
LVST	Large Volume Sequestration Test
mD	Millidarcy
MDT	Modular Dynamic Tester
m	Meter(s)
mi	Mile(s)
mg	milligram(s)
Mg	Magnesium
MGSC	Midwest Geological Sequestration Consortium
MIT	Mechanical Integrity Test
MVA	Monitoring, Verification, and Accounting
MRSCP	Midwest Geological Carbon Sequestration Consortium
NaCl	Sodium Chloride

Acronym/Abbreviation	Definition
N	Nitrogen
Ne	Neon
NETL	National Energy Technology Laboratory
NNSA	National Nuclear Security Administration
O/O_2	Oxygen
ORD	NETL's Office of Research and Development
ORNL	Oak Ridge National Laboratories
OST	DOE's Office of Science and Technology
P	Pressure
PC	Pulverized Coal
PCOR	Plains CO_2 Reduction Partnership
PFC	Perfluorocarbon(s)
PFT	Perfluorocarbon Tracers
PNC	Pulsed Neutron Capture
ppm	Parts per Million
ppmv	Parts per Million by Volume
psi	Pounds per Square Inch
PTRC	Petroleum Technology Research Centre
QC	Quality Control
R&D	Research and Development
RCSP	Regional Carbon Sequestration Partnership
RGGI	Regional Greenhouse Gas Initiative
Rn	Radon
RST	Reservoir Saturation Tool
S	Sulfur
SAPT	Standard Annular Pressure Test
SAR	Synthetic Aperture Radar
scfd	Standard Cubic Feet per Day
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SF_6	Sulfur Hexafluoride
SNL	Sandia National Laboratory
SO_4	Sulfate
SP	Self-Potential/Spontaneous Polarization
STEM	Scanning Transmission Electron Microscope
SWP	Southwest Regional Partnership
T	Temperature
TAME	The Andersons Marathon Ethanol (Plant)
TDS	Total Dissolved Solids
USDW	Underground Sources of Drinking Water
UIC	Underground Injection Control
USGS	U.S. Geological Survey
USIT	Ultrasonic Imaging Tool
VDL	Variable Density Log
VSP	Vertical Seismic Profile
WestCarb	West Coast Regional Carbon Sequestration Partnership
Xe	Xenon
ZEPP-1	Zero-Emissions Power Plant
ZERT	Zero Emission Research and Technology

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Executive Summary

This document should be of interest to a broad audience interested in reducing greenhouse gas (GHG) emissions to the atmosphere. It was developed for regulatory organizations, project developers, and national and state policymakers to increase awareness of existing and developing monitoring, verification, and accounting (MVA) techniques. Carbon dioxide (CO_2) sinks are a natural part of the carbon cycle; however, natural terrestrial sinks are not sufficient to absorb all the CO_2 emitted to the atmosphere each year. Due to present concerns about global climate change related to GHG emissions, efforts are underway to assess CO_2 sinks, both terrestrial and geologic, as a form of carbon management to offset emissions from fossil fuel combustion and other human activities. Reliable and cost-effective MVA techniques are an important part of making geologic sequestration (sometimes referred to as GS) a safe, effective, and acceptable method for GHG control.

MVA of GS sites is expected to serve several purposes, including addressing safety and environmental concerns; inventory verification; project and national accounting of GHG emissions reductions at GS sites; and evaluating potential regional, national, and international GHG reduction goals. The primary goal of the U.S. Department of Energy's (DOE) Carbon Sequestration and MVA Programs is to develop and demonstrate a broad portfolio of Primary, Secondary, and Potential Additional technologies, applications, and accounting requirements that can meet DOE's defined goals of demonstrating 95 percent and 99 percent retention of CO_2 through GS by 2008 and 2012, respectively. The 95 percent and 99 percent retention levels are defined by the ability of a GS site to detect leakage of CO_2, at levels of 5 percent and 1 percent of the stored amount of CO_2, into the atmosphere.

The MVA Program employs multiple Primary, Secondary, and Potential Additional Technologies (see Appendices I, II, and III for definitions) in several GS injection projects worldwide. Each GS site varies significantly in risk profile and overall site geology, including target formation depth, formation porosity, permeability, temperature, pressure, and seal formation. MVA packages selected for commercial-scale projects discussed are tailored to site-specific characteristics and geological features. The MVA packages for these projects were selected to maximize understanding of CO_2 behavior and determine what monitoring tools are most effective across different geologic regimes (as opposed to tailoring a site-specific MVA package). As defined in this report, available Primary technologies are already fully capable of meeting and exceeding monitoring requirements and achieving the MVA goals for 2008. It is believed that by 2012, modifications and improvements to monitoring protocols through the development of Secondary and Potential Additional technologies will reduce GS cost and enable 99 percent of injected CO_2 to be credited as net emissions reduction.

In the outlined approach, prior to operation, site characterization and associated risk assessment play a significant role in determining an appropriate monitoring program. Accredited projects are assumed to require a robust overall monitoring program for inventory verification for accounting of GHG emissions and GHG registries. The overall goal for monitoring will be to demonstrate to regulatory oversight bodies that the practice of GS is safe, does not create significant adverse local environmental impacts, and is an effective GHG control technology. In general, the goals of MVA for GS are to:

- Improve understanding of storage processes and confirm their effectiveness.
- Evaluate the interactions of CO_2 with formation solids and fluids.
- Assess environmental, safety, and health (ES&H) impacts in the event of a leak to the atmosphere.
- Evaluate and monitor any required remediation efforts should a leak occur.
- Provide a technical basis to assist in legal disputes resulting from any impact of sequestration technology (groundwater impacts, seismic events, crop losses, etc.).

As outlined in this report, GS of CO_2 requires pre-operation, operation, closure, and post-closure monitoring activities at the storage site, as well as risk assessment and development of flexible operational plans, and mitigation strategies that can be implemented should a problem arise. Effective application of monitoring technologies ensures the safety of carbon capture and storage (CCS) projects with respect to both human health and the environment and provides the basis for establishing accounting protocols for GHG registries and carbon credits on trading markets for stored CO_2, if necessary.

Since its inception in 1997, DOE's Carbon Sequestration Program – managed within the Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL) – has been developing both core and supporting technologies through which CCS can become an effective and economically viable option for reducing CO_2 emissions from coal-based power plants and other sources. Successful research and development (R&D) will enable CCS technologies to overcome various technical, economic, and social challenges, such as cost-effective CO_2 separation and transport, long-term stability of CO_2 storage in underground formations, monitoring and verification, integration with power generation systems, and public acceptance.

In July 2008, the U.S. Environmental Protection Agency (EPA) proposed Draft Federal requirements under the Safe Drinking Water Act (SDWA) for the underground injection of CO_2 for GS purposes. EPA is tracking the progress and results of national and international GS research projects. DOE leads experimental field research on GS in the United States through the Regional Carbon Sequestration Partnerships (RCSP) Program. EPA is using the data and experience developed in the Core R&D Program, international projects, and RCSP Program to provide a foundation to support decisions for development of an effective regulatory and legal environment for the safe, long-term underground injection and GS of GHGs. Furthermore, information gained from the RCSPs' large- and small-scale geologic injection projects is predicted to provide the technical basis to account for stored CO_2 in support of any future GHG registries, incentives, or other policy instruments that may be deemed necessary in the future. Once the additional regulatory framework at the Federal and state levels is completed, based in part on the monitoring technologies and operational procedures employed by the demonstration projects undertaken by the RCSPs, proper standards will be in place to ensure a consistent and effective permitting and monitoring system for commercial-scale GS projects.

The life cycle of a GS project involves four phases. Monitoring activities will vary among these phases:

1. **Pre-Operation Phase:** Project design is carried out, baseline conditions are established, geology is characterized, and risks are identified.
2. **Operation Phase:** Period of time during which CO_2 is injected into the storage reservoir.
3. **Closure Phase:** Period after injection has stopped, during which wells are abandoned and plugged, equipment and facilities are removed, and agreed upon site restoration is accomplished. Only necessary monitoring equipment is retained.
4. **Post-Closure Phase:** Period during which ongoing monitoring is used to demonstrate that the storage project is performing as expected and that it is safe to discontinue further monitoring. Once it is satisfactorily demonstrated that the site is stable, monitoring will no longer be required except in the very unlikely event of leakage, or legal disputes, or other matters that may require new information about the status of the storage project.

Each monitoring phase (Pre-Operational, Operational, Closure, and Post-Closure) of a GS project will employ specialized monitoring tools and techniques that will address specific atmospheric, near-surface hydrologic, and deep-subsurface monitoring needs.

DOE-sponsored RCSP projects will move CCS from research to commercial application. Such demonstrations are necessary to increase understanding of trapping mechanisms, to test and improve monitoring techniques and mathematical models, and to gain public acceptance of CCS. Testing under a wide range of geologic conditions will demonstrate that CCS is an acceptable GHG mitigation option for many areas of the country, and the world.

Modeling and monitoring R&D targets for RCSP projects include:

- Assessing the sweep efficiency as large volumes of CO_2 are injected to better quantify CO_2 storage capacity.
- Quantifying the pressure effects and brine movement though heterogeneous rock to better understand the significance of these effects on capacity and monitor pressure and brine migration.
- Quantifying inter-well interactions as large plumes develop, focusing on interaction of pressure, heterogeneity, and gravity as controls on migration.
- Better understanding pressure and capillary seals.
- Developing and assessing the effectiveness of existing and novel monitoring tools.
- Assessing how these monitoring tools can be used efficiently, effectively, and hierarchically in a mature monitoring environment.

As outlined in this report, critical components of a robust MVA program include evaluating and determining which monitoring techniques are most effective and economic for specific geologic situations and obtaining information that will be vital in guiding future commercial projects. The monitoring programs of five selected GS projects taking place in the United States are provided. Each project is sited in an area considered suitable for GS and employs a robust monitoring program (for research purposes) to measure physical and chemical phenomena associated with large-scale CO_2 injection. The five projects discussed in this report are:

1. **Gulf Coast Mississippi Strandplain Deep Sandstone Test (Moderate Porosity and Permeability):** GS test located in the southeast portion of the United States will be conducted in the down dip "water leg" of the Cranfield Unit in Southwest Mississippi. Large volumes of CO_2 from a natural source will be delivered by an established pipeline.
2. **Nugget Sandstone Test (High Depth, Low Porosity and Permeability):** Large volume sequestration test (LVST) in the Triassic Nugget Sandstone Formation on the Moxa Arch of Western Wyoming. The source of the CO_2 is the waste gas from a helium (He) and methane (CH_4) production facility.
3. **Cambrian Mt. Simon Sandstone Test (Moderate Depth, Low Porosity and Permeability):** A large-scale injection test in Illinois is being conducted in the Midwest Region of the United States. The main goal of this large-scale injection will be to implement geologic injection tests of sufficient scale to promote understanding of injectivity, capacity, and storage potential in reservoir types having broad importance across the Midwest Region.
4. **San Joaquin Valley Fluvial-Braided Deep Sandstone Test (High Porosity and Permeability):** Large-scale injection of CO_2 into a deep saline formation beneath a power plant site (the Olcese and/or Vedder sandstones of the San Joaquin Valley, California).
5. **Williston Basin Deep Carbonate EOR Test:** CO_2 sequestration and enhanced oil recovery (EOR) in select oil fields in the Williston Basin, North Dakota. A minimum of 500,000 tons per year of CO_2 from an anthropogenic source (pulverized coal [PC] plant) will be injected into an oil reservoir in the Williston Basin.

Each site varies significantly in overall site geology, including target formation depth, formation porosity, permeability, temperature, pressure, and seal formation. The MVA packages for these case studies were selected to maximize understanding of CO_2 behavior and determine what monitoring tools are most effective across different geologic regimes, as opposed to tailoring a site-specific MVA package.

Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations

1.0 Introduction

Atmospheric levels of CO_2 have risen significantly from preindustrial levels of 280 parts per million (ppm) to present levels of 384 ppm (Tans, 2008). Evidence suggests the observed rise in atmospheric CO_2 levels is the result of expanded use of fossil fuels for energy. Predictions of increased global energy use during this century indicate a continued increase in carbon emissions (EIA, 2007) and rising concentrations of CO_2 in the atmosphere unless major changes are made in the way energy is produced and used; in particular, how carbon is managed (Socolow et al., 2004; Greenblatt and Sarmiento, 2004). CO_2 sinks are a natural part of the carbon-cycle; however, natural sinks are unable to absorb all of the CO_2 emitted into the atmosphere each year. Due to present concerns about global climate change related to CO_2 emissions, efforts are underway to better utilize both terrestrial and geologic CO_2 sinks as a form of carbon management to offset emissions derived from fossil fuel combustion and other human activities.

The storage of industrially generated CO_2 in deep geologic formations is being seriously considered as a method for reducing CO_2 emissions into the atmosphere. This growing interest has lead to significant investment by governments and the private sector to develop the necessary technology and to evaluate whether this approach to CO_2 control could be implemented safely and effectively. Depleted oil and gas reservoirs, unmineable coalbeds, and deep brine-filled (saline) formations are all being considered as potential storage options. Depleted oil and gas reservoirs are particularly suitable for this purpose, as they have shown by the test of time that they can effectively store buoyant fluids like oil, gas, and CO_2. In principle, storage in deep brine-filled formations is the same as storage in oil or gas reservoirs, but the geologic seals that would keep the CO_2 from rapidly rising to the ground surface need to be characterized and demonstrated to be suitable for long-term storage. Over hundreds to thousands of years, some fraction of the CO_2 is expected to dissolve in the native formation fluids. Some of the dissolved CO_2 will react with formation minerals and dissolved constituents and may precipitate as carbonate minerals, although this might take a long time. Once dissolved or precipitated as minerals, CO_2 is no longer buoyant and storage security may be increased (Benson and Myer, 2002). Coalbeds offer the potential for a different type of storage in which CO_2 becomes chemisorbed on the solid coal matrix.

1.1 Importance of CO_2 Monitoring and Accounting Protocols

Reliable and cost-effective monitoring will be an important part of making GS a safe, effective, and acceptable method for CO_2 control. Monitoring will be required as part of the permitting process for underground injection and will be used for a number of purposes, such as tracking the location of the plume of injected CO_2, ensuring that injection and abandoned wells are not leaking, and verifying the quantity of CO_2 that has been injected underground. Additionally, depending on site-specific considerations, monitoring may be required to ensure that natural resources, such as groundwater and ecosystems, are protected and that the local population is not exposed to unsafe concentrations of CO_2.

An overview of various aspects of monitoring CO_2 storage projects is provided by the Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage (http://www.ipcc.ch/ipccreports/srccs.htm). The implementation of protocols that ensure that results can be confirmed is essential to an effective monitoring program. Approval of the International Organization for Standardization (ISO) 14064[1] and 14065[2] by over 45 countries and the American National Standards Institute (ANSI, 2007) provides the foundation for developing protocols to validate and verify GS of CO_2. Accredited projects will be required to develop an overall framework that defines the site characteristics and monitoring program for verification. Independent verification bodies assess the ability of the overall framework to verify stored

[1] ISO 14064 is a published standard for GHG accounting and verification. ISO 14064 aims to promote consistency, transparency, and credibility in GHG quantification, monitoring, reporting, and verification.

[2] ISO 14065 specifies principles and requirements for bodies that undertake validation or verification of GHG assertions.

volumes of CO_2. Evaluating a project by applying ISO 14064 and 14065 standards (ISO, 2006; ISO, 2007) recognizes that a balance must be established between practicality and cost for a monitoring program, while still providing accurate and transparent evidence to ensure that CO_2 is effectively stored. The standards are applicable to a broad spectrum of industries and will support work already underway within established GHG programs, such as The Climate Registry, the California Climate Action Registry, the Chicago Climate Exchange (CCX), and the Regional Greenhouse Gas Initiative (RGGI).

1.2 Regulatory Compliance

Eventually commercial scale CO_2 storage projects will require a new regulatory framework that addresses the unresolved issues regarding the regulation of a large, industrial-scale CCS program in order to facilitate safe and economic capture, transportation, subsurface injection, and long-term GS and monitoring of CO_2. In July 2008, EPA proposed Federal Regulations under the SDWA for underground injection of CO_2 for the purpose of GS (Federal Register, July 25, 2008). EPA is tracking the progress and results of national and international GS research projects. DOE leads experimental field research on GS in the United States in conjunction with the RCSP Program. EPA is using the data and experience of domestic and international projects. The RCSP Program is providing a foundation support decisions in the development of an effective regulatory and legal environment for the safe, long-term underground injection and GS of CO_2. Furthermore, information gained from large- and small-scale geologic injection projects will contribute to the accounting of stored CO_2 to support future GHG registries, incentives, or other policy instruments that may arise in the future. A discussion on CCS regulatory issues, including specific mandatory monitoring requirements outlined by Underground Injection Control (UIC) permits, and a breakdown of the UIC permits issued (by well class) to the RCSP Phase II and Phase III projects is in Chapter 4.

1.3 Objective and Goals of Monitoring

The principal goal of DOE's Carbon Sequestration Program is to gain a scientific understanding of carbon sequestration options and to provide cost-effective, environmentally sound technology options that ultimately may lead to a reduction in CO_2 emissions. The program's overarching goals are presented in Table 1-1. The primary Carbon Sequestration Program MVA goal is to develop technology applications that enable recognition of leakage to the atmosphere and shallow subsurface in order to ensure 95 percent retention of stored CO_2 in 2008 and 99 percent retention of stored CO_2 in 2012.

Table 1-1: DOE MVA Goals Outline and Milestones

Year	Goal
2008	Develop MVA protocols that enable recognition of leakage to the atmosphere and shallow subsurface in order to ensure 95 percent retention of stored CO_2.
2012	Develop MVA protocols that enable recognition of leakage to the atmosphere and shallow subsurface in order to ensure 99 percent retention of stored CO_2.

Source: Carbon Sequestration Program Environmental Reference Document, 2007b

A range of techniques capable of ensuring that leakage pathways have not developed and that CO_2 has remained in the subsurface are available for monitoring CO_2 storage. Further description of how monitoring will achieve specific NETL-based MVA goals is described in Section 5.7.

Monitoring will be essential for the successful implementation of GS. The overall goals for monitoring are to demonstrate to regulatory oversight bodies that the practice of GS is safe, does not create significant adverse local environmental impacts, and that it is an effective CO_2 control technology. In general, the goals of MVA for GS are to (Litynski et al., 2008):

- Identify storage processes and confirm their integrity
- Evaluate the interactions of CO_2 with formation solids and fluids
- Assess potential environmental, health, and safety effects in the event of a leak
- Evaluate and monitor mitigation efforts should a leak occur
- Assist in mediating legal disputes resulting from any impact of sequestration technology (groundwater impacts, seismic events, crop losses, etc.)

1.4 Monitoring Activities

GS of CO_2 requires pre-operation, operation, closure, and post-closure monitoring activities (described in Section 5.0) at the storage site, as well as risk assessment and development of mitigation strategies that can be implemented should a problem arise. The effective application of monitoring technologies ensures the safety of CCS projects, with respect to both human health and the environment, and will contribute greatly to the development of relevant technical approaches for monitoring and verification. The development, application, and reporting of results from MVA strategies for projects must be integrated with the multidisciplinary team working to design and operate GS projects. Site characterization and simulation activities will help to design a robust MVA system that will provide data to validate expected results, monitor for signals of leakage, and provide confidence that the CO_2 remains in the subsurface. All of these project activities will need to support an interactive risk assessment process focused on identifying and quantifying potential risks to humans and the environment associated with geologic CO_2 storage and helps to ensure that these risks remain low throughout the life cycle of a GS project. Through the development, modification, and application of well-selected and designed monitoring technologies, CCS risks are estimated to be comparable to those associated with current oil and gas operations (Benson et al., 2005a). Appendix IV presents a summary of the purpose for monitoring during the various phases of a GS project.

Considerable effort in the GEO-SEQ project was devoted to assessing and demonstrating the application of geophysical methods for monitoring subsurface processes of interest in GS projects. GEO-SEQ is a public-private applied R&D partnership, formed with the goal of developing the technology and information needed to enable safe and cost-effective GS by the year 2015. The workflow for application of geophysical methods in a GS project involves the following steps:

- Identify subsurface processes or targets relevant to the particular monitoring activity of interest
- Select the suite of geophysical techniques best suited for the subsurface measurements
- Perform a baseline set of measurements before CO_2 injection
- Repeat measurements at intervals during and after injection
- Interpret results, focusing on time-lapse changes (LBNL, 2004)

1.5 Need for Multiple Projects with Varying Geologic Characteristics

Although the types and quantities of point source CO_2, as well as the cost of capturing the CO_2 could influence commercial deployment rates of storage technologies, availability of CO_2 is not expected to be a limiting factor in technology application. Rather, long-term carbon sequestration deployment would be influenced to a greater degree by the presence of suitable geologic resources (sinks). The best geologic carbon sink formations capable of storing CO_2 include oil and gas bearing formations, saline formations, basalt, deep coal seams, and oil- or gas-rich shales. Not all geologic formations are suitable for CO_2 storage; some are too shallow and others have poor confining characteristics or low permeability (the ability of rock to transmit fluids through pore spaces). Formations suitable for CO_2 storage have specific characteristics that include thick accumulations of sediments or rock layers, permeable layers saturated with saline water (saline formations), coupled with extensive covers of low porosity sediments or rocks acting as seals (cap rock), structural simplicity, and lack of faults (IPCC, 2005). Geographical differences across the United States in fossil fuel use and potential storage sites dictate the use of a regional approach to address carbon sequestration. To accommodate these differences, DOE created a nationwide network of seven RCSPs in 2003 to help determine and implement the technology, infrastructure, and regulations most appropriate for promoting carbon sequestration in different regions of the United States.

Monitoring for CO_2 storage projects should be tailored to the specific conditions and risks at the storage site. For example, if the storage project is in a depleted oil reservoir with a well-defined cap rock and storage trap, the most likely pathways for leakage are the injection wells themselves or the plugged abandoned wells from previous reservoir operations. In this case, the monitoring program should focus on assuring proper performance of all wells in the area, and ensuring that they are not leaking CO_2 to the surface or shallow aquifers. However, if a project is in a brine-filled reservoir where the cap rock is less well defined, or lacks a local structural trap, the monitoring program should focus on tracking the migration of the plume and ensuring that it does not leak through discontinuities in the cap rock. Similar arguments can be made about projects where solubility or mineral trapping is a critical component of the storage security. In this case, it would be necessary to demonstrate that the geochemical interactions were effective and progressing as predicted.

The value of taking a tailored approach to monitoring is two-fold. First, the monitoring program focuses on the largest risks. Second, since monitoring may be expensive, a tailored approach will enable the most cost-effective use of monitoring resources. However, it is likely that there will likely be a minimum set of monitoring requirements that will be based on experience and regulations from related activities like natural gas storage, CO_2 EOR, and disposal of industrial wastes in deep geologic formations (Benson et al., 2002b).

2.0 Monitoring Techniques

Table 2-1 is a list of MVA techniques tested or proposed to be employed in geologic CO_2 storage projects being implemented by the RCSPs and others. A brief description of each method is provided in the table, along with the benefits and challenges. Further details are provided in Appendices I (atmospheric monitoring), II (near-surface monitoring), and III (subsurface monitoring). Note that the tools are used in more than one setting; however, the same technique can have different benefits at different depths.

Table 2-1: Comprehensive List of Proposed Monitoring Methods Available for GS Projects

Atmospheric Monitoring Techniques*	
Monitoring Technique	**Description, Benefits, and Challenges**
CO_2 Detectors	***Description:*** Sensors for monitoring CO_2 either intermittently or continuously in air.
	Benefits: Relatively inexpensive and portable. Mature and new technologies represented.
	Challenges: Detect leakage above ambient CO_2 emissions (signal to noise).
Eddy Covariance	***Description:*** Atmospheric flux measurement technique to measure atmospheric CO_2 concentrations at a height above the ground surface.
	Benefits: Mature technology that can provide accurate data under continuous operation.
	Challenges: Very specialized equipment and robust data processing required. Signal to noise.
Advanced Leak Detection System	***Description:*** A sensitive three-gas detector (CH_4, Total HC, and CO_2) with a GPS mapping system carried by aircraft or terrestrial vehicles.
	Benefits: Good for quantification of CO_2 fluxes from the soil.
	Challenges: Null result if no CO_2.
Laser Systems and LIDAR	***Description:*** Open-path device that uses a laser to shine a beam – with a wavelength that CO_2 absorbs – over many meters.
	Benefits: Highly accurate technique with large spatial range. Non-intrusive method of data collection over a large area in a short timeframe.
	Challenges: Needs favorable weather conditions. Interference from vegetation, requires time laps Signal to noise.
Tracers (Isotopes)	***Description:*** Natural isotopic composition and/or compounds injected into the target formation along with the CO_2.
	Benefits: Used to determine the flow direction and early leak detection.
	Challenges: Samples need analyzed offsite of project team does not have the proper analytical equipment.

*See Appendix I for Details

Near-Surface Monitoring**	
Monitoring Technique	**Description, Benefits, and Challenges**
Ecosystem Stress Monitoring	***Description:*** Satellite or airplane-based optical method.
	Benefits: Easy and effective reconnaissance method.
	Challenges: Detection only after emission has occurred. Quantification of leakage rates difficult. Changes not related to CCS lead to false positives. Not all ecosystems equally sensitive to CO_2.
Tracers	***Description:*** CO_2 soluble compounds injected along with the CO_2.into the target formation
	Benefits: Used to determine the hydrologic properties, flow direction and low-mass leak detection.
	Challenges: Many of the tested CO_2-soluble tracers are GHGs, and therefore, add to risk profile.
Groundwater Monitoring	***Description:*** Sampling of water or vadose zone/soil (near surface) for basic chemical analysis.
	Benefits: Mature technology, easier detection than atmospheric. Early detection prior to large emissions.
	Challenges: Significant effort for null result (no CO_2 leakage). Relatively late detection of leakage.
Thermal Hyperspectral Imaging	***Description:*** An aerial remote-sensing approach primarily for enhanced coalbed methane recovery and sequestration.
	Benefits: Covers large areas; detects CO_2 and CH_4.
	Challenges: Not a great deal of experience with this technique in GS.
Synthetic Aperture Radar (SAR & InSAR)	***Description:*** A satellite-based technology in which radar waves are sent to the ground to detect surface deformation.
	Benefits: Large-scale monitoring (100 km x 100 km).
	Challenges: Best used in environments with minimal topography, minimal vegetation, and minimal land use. Only useful in time-laps.
Color Infrared (CIR) Transparency Films	***Description:*** A vegetative stress technology deployed on satellites or aerially.
	Benefits: Good indicator of vegetative health, which can be an indicator of CO_2 or brine leakage.
	Challenges: Detection only post-leakage. Need for deployment mechanism (i.e. aircraft).
Tiltmeter	***Description:*** Measures small changes in elevation via mapping tilt , either on the surface or in subsurface.
	Benefits: Mature oil field technology for monitoring stream or water injection, CO_2 flooding and hydrofracturing.
	Challenges: Access to surface and subsurface. Measurements are typically collected remotely.
Flux Accumulation Chamber	***Description:*** Quantifies the CO_2 flux from the soil, but only from a small, predetermined area.
	Benefits: Technology that can quickly and effectively determine CO_2 fluxes from the soil at a predetermined area.
	Challenges: Only provides instantaneous measurements in a limited area.

**See Appendix II for Details

Near-Surface Monitoring**	
Monitoring Technique	**Description, Benefits, and Challenges**
Induced Polarization	***Description:*** Geophysical imaging technology commonly used in conjunction with DC resistivity to distinguish metallic minerals and conductive aquifers from clay minerals in subsurface materials.
	Benefits: Detecting metallic materials in the subsurface with fair ability to distinguish between different types of mineralization. Also a useful technique in clays.
	Challenges: Does not accurately depict non-metallic based materials. Typically used only for characterization.
Spontaneous (Self) Potential	***Description:*** Measurement of natural potential differences resulting from electrochemical reactions in the subsurface. Typically used in groundwater investigations and in geotechnical engineering applications for seepage studies.
	Benefits: Fast and inexpensive method for detecting metal in the near subsurface. Useful in rapid reconnaissance for base metal deposits when used in tandem with EM and geochemical techniques.
	Challenges: Should be used in conjunction with other technologies. Qualitative only.
Soil and Vadose Zone Gas Monitoring	***Description:*** Sampling of gas in vadose zone/soil (near surface) for CO_2.
	Benefits: CO_2 retained in soil gasses provides a longer residence time. Detection of elevated CO_2 concentrations well above background levels provides indication of leak and migration from the target reservoir.
	Challenges: Significant effort for null result (no CO_2 leakage). Relatively late detection of leakage.
Shallow 2-D Seismic	***Description:*** Closely spaced geophones along a 2-D seismic line.
	Benefits: Mature technology that can provide high resolution images of the presence of gas phase CO_2. Can be used to locate "bright spots" that might indicate gas, also/ used in time-laps.
	Challenges: Semi-quantitative. Cannot be used for mass-balance CO_2 dissolved or trapped as/mineral not monitored. Out of plane migration not monitored.

**See Appendix II for Details

Subsurface Monitoring***	
Monitoring Technique	**Description, Benefits, and Challenges**
Multi-component 3-D Surface Seismic Time-lapse Survey	***Description:*** Periodic surface 3-D seismic surveys covering the CCS reservoir.
	Benefits: Mature technology that can provide high-quality information on distribution and migration of CO_2. Best technique for map view coverage. Can be used in multi-component form (ex. three, four, or nine component), to account for both compressional waves (P-waves) and shear waves (S-waves).
	Challenges: Semi-quantitative. Cannot be used for mass-balance CO_2 dissolved or trapped as/mineral not monitored. Signal to noise, not sensitive to concentration. Thin plumes or low CO_2 concentration may not be detectable.
Vertical Seismic Profile (VSP)	***Description:*** Seismic survey performed in a wellbore with multi-component processes. Can be implemented in a "walk-away" fashion in order to monitor the footprint of the plume as it migrates away from the injection well and in time-lapse application.
	Benefits: Mature technology that can provide robust information on CO_2 concentration and migration. More resolution than surface seismic by use of a single wellbore. Can be used for calibration of a 2-D or 3-D seismic.
	Challenges: Application limited by geometry surrounding a wellbore.
Magnetotelluric Sounding	***Description:*** Changes in electromagnetic field resulting from variations in electrical properties of CO_2 and formation fluids.
	Benefits: Can probe the Earth to depths of several tens of kilometers.
	Challenges: Immature technology for monitoring of CO_2 movement. Relatively low resolution.
Electromagnetic Resistivity	***Description:*** Measures the electrical conductivity of the subsurface including soil, groundwater, and rock.
	Benefits: Rapid data collection.
	Challenges: Strong response to metal. Sensitivity to CO_2.
Electromagnetic Induction Tomography (EMIT)	***Description:*** Utilizes differences in how electromagnetic fields are induced within various materials.
	Benefits: Provides greater resolution and petrophysical information than ERT.
	Challenges: Difficult to execute. Requires non-conductive casing downhole to obtain high–frequency data. Esoteric technique, not proven for GS.
Injection Well Logging (Wireline Logging)	***Description:*** Wellbore measurement using a rock parameter, such as resistivity or temperature, to monitor fluid composition in wellbore (Specific wireline tools expanded in Appendix III).
	Benefits: Easily deployed technology and very useful for wellbore leakage.
	Challenges: Area of investigation limited to immediate wellbore. Sensitivity of tool to fluid change.
Annulus Pressure Monitoring	***Description:*** A mechanical integrity test on the annular volume of a well to detect leakage from the casing, packer or tubing. Can be done constantly.
	Benefits: Reliable test with simple equipment. Engineered components are known to be areas of high frequency.
	Challenges: Periodic mechanical integrity testing requires stopping the injection process during testing. Limited to constructed system.

***See Appendix III for Details

Subsurface Monitoring***	
Monitoring Technique	**Description, Benefits, and Challenges**
Pulsed Neutron Capture	***Description:*** A wireline tool capable of depicting oil saturation, lithology, porosity, oil, gas, and water by implementing pulsed neutron techniques.
	Benefits: High resolution tool for identifying specific geologic parameters around the well casing. Most quantitative to CO_2 saturation in time-lapse.
	Challenges: Geologic characteristics identified only in the vicinity of the wellbore. Not sensitive to dissolution trapped and mineral trapped CO_2. Sensitive to borehole conditions, fluid invasion because of workover. Decreased sensitivity in lower salinity water, at low saturation.
Electrical Resistance Tomography (ERT)	***Description:*** Use of vertical arrays of electrodes in two or more wells to monitor CO_2 as a result of changes in layer resistivity.
	Benefits: Potential high resolution technique to monitor CO_2 movement between wells.
	Challenges: Immature technology for monitoring of CO_2 movement. Processes such as mass-balance and dissolution/mineral trapping difficult to interpret. Poor resolution and limited testing in GS applications.
Sonic (Acoustic) Logging	***Description:*** A wireline log used to characterize lithology, determine porosity, and travel time of the reservoir rock.
	Benefits: Oil field technology that provides high resolution. Can be used to time seismic sections.
	Challenges: Does not yield data on hydraulic seal. May have to make slight corrects for borehole eccentricity. Not a "stand alone" technology. Should be used in conjunction with other techniques.
2-D Seismic Survey	***Description:*** Acoustic energy, delivered by explosive charges or vibroseis trucks (at the surface) is reflecting back to a straight line of recorders (geophones). After processing, the reflected acoustic signature of various lithologies is presented as a 2-D graphical display.
	Benefits: Can be used to monitor "bright spots" of CO_2 in the subsurface. Excellent for shallow plumes as resolution decreases with depth.
	Challenges: Coverage limited to lines.
Time-lapse Gravity	***Description:*** Use of gravity to monitor changes in density of fluid resulting from injection of CO_2.
	Benefits: Effective technology.
	Challenges: Limited detection and resolution unless gravimeters are located just above reservoir, which significantly increases cost. Sensitivity.
Density Logging (RHOB Log)	***Description:*** Continuous record of a formation bulk density as a function of depth by accounting for both the density of matrix and density of liquid in the pore space.
	Benefits: Effective technology that can estimate formation density and porosity at varying depths.
	Challenges: Lower resolution log compared to other wireline methods.
Optical Logging	***Description:*** Device equipped with optical imaging tools is lowered down the length of the wellbore to provide detailed digital images of the well casing.
	Benefits: Simple and cheap technology that provides qualitative well integrity verification at depth.
	Challenges: Does not provide information beyond what is visible inside the well casing.

***See Appendix III for Details

Subsurface Monitoring***	
Monitoring Technique	**Description, Benefits, and Challenges**
Cement Bond Log (Ultrasonic Well Logging)	***Description:*** Implement sonic attenuation and travel time to determine whether casing is cemented or free. The more cement which is bonded to casing, the greater will be the attenuation of sounds transmitted along the casing. Used to evaluate the integrity of the casing cement and assessing the possibility of flow outside of casing.
	Benefits: Evaluation of quality of engineered well system prior to leakage, allows for proactive remediation of engineered system. Indicates top of cement, free pipe, and gives an indication of well cemented pipe. Authorized as an MIT tool for the demonstration of external integrity of injection wells.
	Challenges: Good centralization is important for meaningful and repeatable cement bond logs. Cement bond logs should not be relied on for a quantitative evaluation of zonal isolation or hydraulic integrity. The cement should be allowed to cure for at least 72 hours before logging.
Gamma Ray Logging	***Description:*** Use of natural gamma radiation to characterize the rock or sediment in a borehole.
	Benefits: Common and inexpensive measurement of the natural emission of gamma rays by a formation.
	Challenges: Subject to error when a large proportion of the gamma ray radioactivity originates from the sand-sized detrital fraction of the rock. Limited to site characterization phase.
Microseismic (Passive) Survey	***Description:*** Provides real-time information on hydraulic and geomechanical processes taking place within the reservoir in the interwell region, remote from wellbores by implementing surface or subsurface geophones to monitor earth movement.
	Benefits: Technology with broad area of investigation that can provide provides high-quality, high resolution subsurface characterization data and can provide effects of subsurface injection on geologic processes.
	Challenges: Dependence on secondary reactions from CO_2 injection, such as fracturing and faulting. Difficult to interpret low rate processes (e.g., dissolution/mineral trapping and slow leakage). Extensive data analysis required.
Crosswell Seismic Survey	***Description:*** Seismic survey between two wellbores in which transmitters and receivers are placed in opposite wells. Enables subsurface characterization between those wells. Can be used for time-lapse studies.
	Benefits: Crosswell seismic profiling provides higher resolution than surface methods, but sample a smaller volume.
	Challenges: Mass-balance and dissolution/mineral trapping difficult to monitor.
Aqueous Geochemistry	***Description:*** Chemical measurement of saline brine in storage reservoir.
	Benefits: Coupled with repeat analyses during and after CO_2 injection can provide mass-balance and dissolution/mineral trapping information.
	Challenges: Cannot image CO_2 migration and leakage directly. Only near-well fluids are measured.
Resistivity Log	***Description:*** Log of the resistivity of the formation, expressed in ohm-m, to characterize the fluids and rock or sediment in a borehole.
	Benefits: Used for characterization, also sensitive to changes in fluids.
	Challenges: Resistivity can only be measured in open hole or non-conducive casing.

***See Appendix III for Details

3.0 Developments in Monitoring Techniques from DOE Supported and Leveraged Monitoring Activities

Since its inception in 1997, DOE's Carbon Sequestration Program – managed within FE and implemented by NETL – has been developing both core and supporting technologies through which CCS can become an effective and economically viable option for reducing CO_2 emissions from coal-based power plants (NETL, 2007a). Successful R&D will enable CCS technologies to overcome various technical, economic, and social challenges, such as cost-effective CO_2 separation and transport, long-term stability of CO_2 sequestration in underground formations, MVA, integration with power generation systems, and public acceptance. The programmatic timeline is to demonstrate a portfolio of safe and cost-effective CO_2 capture, storage, and mitigation technologies at the commercial scale by 2012, leading to substantial deployment and market penetration beyond 2020.

3.1 Core R&D

DOE's Core R&D Program focuses on developing new MVA technologies and approaches to the point of pre-commercial application. The program's core R&D agenda focuses on increased understanding of CO_2 GS, MVA technology and cost, and regulations and permitting. A major portion of DOE's Core R&D is aimed at providing an accurate accounting of stored CO_2 and a high level of confidence that the CO_2 will remain permanently sequestered. MVA research seeks to develop:

- Instruments that can detect CO_2 in a storage reservoir and/or measure its movement through-time lapse measurements and determine its physical (supercritical, dissolved, gas phase, solid) and chemical state with precision.
- The capability to interpret and analyze the results from such instruments.
- The ability to use modeling to predict how movement and/or chemical reactions of CO_2 in the reservoir will affect: (1) the permanence of storage, (2) the environmental impacts within the reservoir, and (3) human health.
- Best practices and procedures that can be used to respond to any detected changes in the condition of the stored CO_2 in order to mitigate losses of carbon and prevent negative impacts on the environment and human health.

A successful MVA effort will enable sequestration project developers to ensure human health and safety and prevent damage to the host ecosystem. The goal is to provide sufficient information and safeguards to allow developers to obtain permits for sequestration projects. MVA also seeks to support the development of an accounting to validate the retention of CO_2 in deep geologic formation that approaches 100 percent, contributing to the economic viability of sequestration projects.. Finally, MVA should provide improved information and feedback to sequestration practitioners, resulting in accelerated technologic progress.

DOE's Core R&D activities for geologic carbon sequestration and subsequent monitoring activities are generally divided into deep conventional reservoirs (saline formations, depleted oil and gas fields, and EOR fields) and deep, unmineable coal seams. Specific tools and techniques under the MVA Program are classified based on their intended application and purpose (atmospheric, near-surface, or subsurface monitoring). Monitoring techniques are listed in Table 2-1, and those used in saline formations, depleted oil and gas fields, EOR fields and coalbed methane (CBM) or enhanced coalbed methane (ECBM) are outlined below. Core R&D test locations are discussed in Section 3.2. The following discussion highlights some of the research that DOE's Core R&D program has supported through external research projects focused on developing MVA technologies and their application. These technologies may be considered Primary, Secondary, or Potential Additional depending on their capabilities and designed purpose. Their application for a GS project is described in Chapter 5.

3.1.1 Atmospheric Monitoring Methods Developments

The goal of geologic carbon sequestration is to identify CO_2 leakage (should it occur) long before it reaches the surface. Geologically sequestered CO_2 will encounter multiple barriers (seals) with respect to its flow path. CO_2 leakage from a storage reservoir may create significant CO_2 fluxes from the surface that may be difficult to distinguish from background CO_2 fluxes. The magnitude of CO_2 seepage fluxes will depend on a variety of factors, such as the mechanism of emission (e.g., focused CO_2 flow along a near-surface fault or more diffuse emission through sediments) wind, and density-driven atmospheric dispersion. Anomalous surface CO_2 fluxes may be detected using several well-tested and readily available techniques (LBNL, 2004).

Sensors for detecting and monitoring CO_2 in the air are a widely deployed technology (greenhouses, combustion emissions measurement, and breweries), but are mostly used for point sources of CO_2 and operate as infrared gas analyzers (IRGA). When monitoring a large area (several km^2 in area), one solution is to employ an open-path device that uses a laser that shines a beam (with a wavelength that CO_2 absorbs) over many meters. The attenuated beam reflects from a mirror and returns to the instrument for determination of the CO_2 concentration.

Current commercial instruments capable of this cost tens of thousands of dollars. Over the past four years, the California Institute of Technology has been developing an inexpensive (instrument cost of no more than a few hundred dollars), open-path laser instrument to measure CO_2 concentration over the range of interest (300 to 500 parts per million by volume [ppmv]). This alternative differs from commercially available instruments because it detects exclusively CO_2 and not other gases by implementing inexpensive, off-the-shelf components. The instrument is currently being tested and is estimated to have an operating range of 2.5 kilometers (five kilometers round trip).

Eddy covariance (EC), or eddy correlation, is a technique whereby high frequency measurements of atmospheric CO_2 concentration at a certain height above the ground are made by an IRGA, along with measurements of micrometeorological variables such as wind velocity, relative humidity, and temperature. Integration of these measurements allows derivation of the net CO_2 flux over the upwind footprint, typically m^2 to km^2 in area, depending on tower height. The primary limitation of the EC method is that it assumes a horizontal and homogeneous surface, which is rarely found in natural systems. Also, the EC measurement should be made under statistically steady meteorological conditions; morning and evening periods, as well as times of changing weather conditions should be avoided (LBNL, 2004). The GEO-SEQ project has investigated this technique as part of its work on tracers.

3.1.2 Near-Surface Monitoring Methods Developments

In addition to atmospheric gases, subsurface gases may need to be monitored to consider microbial signal, as well as barometric pumping and soil moisture changes. Monitoring for CO_2 migration from the storage reservoir should focus on the shallow subsurface gas geochemistry. Several methods are available to measure surface CO_2 flux and subsurface CO_2 concentration and to determine the origin of CO_2 (LBNL, 2004).

Near-Surface Gas Monitoring – The accumulation chamber (AC) method measures soil CO_2 flux at discrete locations over an area of several square centimeters. In this technique, an AC with an open bottom is placed either directly on the soil surface or on a collar installed on the ground surface, and the contained air is circulated through the AC and an IRGA. The rate of change of CO_2 concentration in the chamber is used to derive the flux of CO_2 across the ground surface at the point of measurement (LBNL, 2004). The NETL Office of Research and Development (ORD) GEO-SEQ project has investigated this technique as part of its work on tracers and it has been used for CO_2 flux measurements at the Frio Brine Pilot.

Two new monitoring systems developed by Los Alamos National Laboratory (LANL) that can detect CO_2 seepage at the soil surface have been engineered, tested in the laboratory, and are now being fitted for field application. The specific tools that have been created to detect CO_2 seepage are oxygen (O_2)/CO_2 measurement systems and radon (^{222}Rn) detectors that are able to continuously measure small amounts of ^{222}Rn (used as a surrogate for adjective flow) and portable stable isotope detectors of CO_2 that can be used for in situ analyses (high temporal resolution at a single point location) and remote analyses (large spatial coverage over a field).

Near-Surface Geochemistry – Near-surface geochemistry methods can be used to detect short-term rapid loss or long-term intermittent leakage of CO_2 from GS formations. These techniques are routinely employed in the environmental consulting industry and include monitoring soil gas and shallow groundwater. In general, both consist of purging the monitoring point and collecting a sample, followed by analysis and interpretation. Soil gas can be collected with sorbents, sample tubes, or Tedlar bags, depending on the compounds expected and the detection level. Groundwater samples are collected in laboratory glassware.

Soil gas and groundwater monitoring for various tracers has been used in several Core R&D projects. Natural tracers (isotopes of carbon [C], O, hydrogen [H], and noble gases associated with the injected CO_2) and introduced tracers (noble gases, sulfur hexafluoride [SF_6], and perfluorocarbons [PFC]) may provide insight about the underground movement of CO_2 and reactions between CO_2 and the geologic formation. Perfluorocarbon tracers (PFT) added to the injected CO_2 can be detected in soil gas at parts-per-quadrillion levels. Natural tracers (Rn and light HCs) can also be used in monitoring CO_2 in soil gas.

Sampling and analysis of local well water and surface soil gas (Strutt et al., 2005) were performed at the Weyburn field. The primary objectives of the soil gas analyses were to measure the natural background concentrations of CO_2 and to ascertain whether CO_2 or associated reservoir tracer gases were escaping to the near surface. Samples were collected three times over the course of two years on a regular spatial grid; additional samples that could represent possible vertical migration pathways were also collected at other sites in the surrounding area.

Near-surface monitoring at the Frio Brine Pilot includes soil gas CO_2 flux and concentration measurements, aquifer chemistry monitoring, and tracer detection of PFC with sorbents in the soil and aquifer. Pre-operation baseline surveys for CO_2 flux and concentration-depth profiles over a wide area and near existing wells were done in 2004. The near-surface research team includes NETL, the Bureau of Economic Geology (BEG) at the Jackson School of Geosciences, Colorado School of Mines, and Lawrence Berkeley National Laboratory (LBNL). The suite of tracers injected with the CO_2 includes PFCs, the noble gases krypton (Kr), neon (Ne), and xenon (Xe), and SF_6 (Hovorka et al., 2005; NETL Website, 2008).

The West Pearl Queen reservoir project also used soil gas surveys to detect PFC tracers that were injected into the reservoir with the CO_2. Soil gas sampling was conducted before and after the CO_2 injection by using capillary tubes and adsorbent packets for the tracers. Brookhaven National Laboratory (BNL) supplied the tracers and performed the tracer concentration analysis (Wells et al., 2007).

Near-Surface Geophysics – The use of magnetometers is another possible near-surface geophysical technique. Magnetometers measure the strength and/or direction of the magnetic field in the vicinity of the instrument. They are typically used in geophysical surveys to find iron deposits because they can measure magnetic field variations caused by the deposits. In an effort to develop comprehensive monitoring techniques to verify the integrity of CO_2 reservoirs, NETL and their partners (listed in Appendix II) have used airborne and ground-based magnetometry in conjunction with CH_4 detection to locate abandoned wells that can be a source of leakage from a potential CO_2 storage reservoir (depleted oil or gas field).

Magnetotelluric surveys (soundings) are a natural-source electromagnetic (EM) geophysical method that utilizes variations in the Earth's magnetic field to image subsurface structures. A magnetotelluric sounding was attempted at Weyburn but has not produced results. Consequently, a final assessment of its utility is not available (Monea et al., 2008).

Electrical resistance tomography (ERT) is a technique of imaging subsurface electrical conductivity. When deployed in time-lapse mode, it is capable of detecting conductivity changes caused by the injection of CO_2. The method utilizes borehole casings as electrodes for both stimulating electrical current in the ground and measuring the electrical potentials that are induced. ERT may be tested in Weyburn Phase II using a single borehole configuration as an economical monitoring alternative for situations that require less detail (Monea et al., 2008).

High precision gravity (microgravity) surveys are a near-surface geophysical technique used to detect changes in subsurface density. The densities of CO_2, typical reservoir fluids, and their mixtures are known or can be obtained by sampling. For most of the depth interval for sequestration, CO_2 is less dense and more compressible than brine or oil, so gravity (and seismic) methods are a candidate for brine or oil bearing formations. The University of California, San Diego, and Statoil have performed two high-precision gravity surveys on the sea floor at the Sleipner gas field off the coast of Norway (an international project covered in section 3.3). The first survey was used to record the baseline gravity, and the second (three years later) was to measure the changes due to continued CO_2 injection. Microgravity surveys were successfully conducted in 2002 and 2005.

3.1.3 Subsurface Monitoring Methods Developments

Simulations – One of the most important purposes of monitoring is to confirm that the project is performing as expected based on predictive models or simulations. This is particularly valuable in the early stages of a project when there is the opportunity to alter the project if it is not performing adequately. Monitoring data collected early in the project are often used to refine and calibrate the predictive model. The refined model then forms the basis for predicting longer-term performance.

Comparing model predictions with monitoring data is the key to model calibration and performance confirmation. While simple in principle, unless the linkage between the model results and monitoring data is considered during the design of the monitoring program, the data needed for model calibration and performance confirmation may not be available. Issues, such as which parameters should be monitored, timing of measurements, spatial scale and resolution of measurements, and location of monitoring points, all need to be considered (Benson, 2002).

The models can be used to predict several reservoir attributes, including fluid pressure, reservoir production and injection rates, numerical reservoir flow simulations, and geochemical simulations. The information used for calibration and performance confirmation include, but are not limited to, downhole pressure, actual injection and production rates, 3-D seismic data, tracer data (reservoir and near-surface), data from geophysical logs, geochemical data from cores, and reservoir fluid test data.

EnCana Corporation, Natural Resources of Canada, and their partners (see Appendix III) at the Weyburn Field have matched reservoir modeling against production and injection statistics and performed repeated and frequent reservoir fluid sampling to understand geochemical mechanisms occurring in the reservoir during the four years of the initial phase of the project (2000 to 2004).

At the Frio Brine Pilot, two groups of modelers, LBNL, using TOUGH2 (non-isothermal multiphase flow model), and the University of Texas Petroleum Engineering Department, using Craig-Geffen-Morse (CGM) water flooding model, input geologic and hydrological information along with assumptions concerning CO_2/brine multiphase behavior to predict the evolving behavior of the injected CO_2 through time. Geochemical modeling by Lawrence Livermore National Laboratory (LLNL) predicted changes in brine composition over time (Hovorka et al., 2005).

At the West Pearl Queen reservoir, two types of numerical simulations (one reservoir and two geochemical) were supervised by LANL. Reservoir flow simulations were run using Eclipse (Schlumberger's oil reservoir simulator) to characterize the reservoir response to varying injection rates. Two types of numerical models were used to characterize the geochemical interactions. The first model, REACT (chemical kinetics simulator), was used to predict the most stable configuration of the system after equilibrium has been achieved along a reaction path with the steady addition of CO_2. The second numerical model, flow and transport simulator (FLOTRAN), was used to explore both short- (months) and long-term (more than 1,000 years) geochemical behavior (Pawar et al., 2006).

Advanced Resources International (ARI) is evaluating the effect of slow or rapid CO_2 leakage on the environment during initial operations and the subsequent storage period. The study will include a comprehensive and multi-disciplinary assessment of the geologic, engineering, and safety aspects of natural analogs. Five large, natural CO_2 fields, which provide a total of 1.5 billion ft^3/day of CO_2 for EOR projects in the United States, have been selected for evaluation. Based on the results of geomechanical modeling, an evaluation of environmental and safety related factors will be completed (Stevens et al., 2001).

Geochemical – Geochemical surveys that monitor the reservoir characteristics have routinely been used in the oil and gas industry and have been successfully adopted for use in monitoring carbon sequestration. Initially, reservoir samples (solids, liquids, and gases) are collected to establish a baseline prior to CO_2 injection; tests can be repeated later to monitor CO_2 migration (using tracers), or to assess geochemical changes, as CO_2 saturated brine reacts with the reservoir formation.

Production fluid sampling and geochemical analyses were conducted at Weyburn at regular intervals of three to four months over a three year period, with the primary objective of tracing the distribution of CO_2 over time within the reservoir. The fluids were analyzed for a broad spectrum of chemical and isotopic parameters, including pH, total alkalinity, calcium (Ca), magnesium (Mg), total dissolved solids (TDS), chlorine (Cl), sulfate (SO_4), and $^{13}C\{HCO_3\}$. The chemical analyses allowed the short-term chemical interaction of the CO_2 with the reservoir fluids and rock matrix to be monitored. The distinct isotopic signature of the injected CO_2 also allowed its migration through the reservoir to be monitored (Monea et al., 2008).

Geochemical analysis of the reservoir sandstone by LANL at the West Pearl Queen Field have led to better understanding of CO_2 reaction products in the sandstone reservoir. Understanding the kinetics of reaction with certain mineral formations (Dawsonite) is critical for sequestration in sandstone reservoirs (Pawar et al., 2006).

An innovative geochemical sampling tool, developed and operated by LBNL to support in-zone fluid chemistry sampling, is the U-tube (Appendix III). This technique was used with great success by LBNL at the Frio Brine Pilot in 2004 (Hovorka et al., 2005) and was redesigned for multi-level geochemical sampling at the Otway Basin Project in southern Australia (considered an international project, see Section 3.3).

Seismic – At the Weyburn Field, multi-component 3-D surface seismic time-lapse surveys were conducted at intervals of approximately 12 months, starting prior to the commencement of CO_2 injection in 2000, and repeated in 2001 and 2002. The resultant time-lapse images (primarily seismic amplitude changes) acquired at Weyburn clearly map the spread of CO_2 over time within the reservoir, fulfilling a key objective set at the outset of the project. However, a detailed, quantitative estimate of CO_2 volumes from the seismic surveys remains elusive due to the multi-phase composition (brine, oil, and CO_2) and pressure-dependent behavior of the reservoir fluids (Monea et al., 2008).

In 2004, Sandia National Laboratory (SNL) and LANL conducted an extensive 3-D seismic survey prior to CO_2 injection in the West Pearl Queen reservoir to provide the best possible baseline subsurface image of the reservoir. After CO_2 was injected and allowed to “soak” into the reservoir for six months, a second 3-D seismic survey was conducted to determine the fate of the CO_2 plume and to provide data to calibrate and modify the simulation models (Pawar et al., 2006).

Microseismic (passive) seismic monitoring was conducted at Weyburn to monitor the dynamic response of the reservoir rock matrix to CO_2 injection (i.e., stress release due to injection-induced deformation) and assess the level of induced seismicity in regard to safety of existing surface infrastructure and as an alternative means of mapping the spread of CO_2 within the reservoir. An array of eight, three-component geophones was permanently installed just above the oil reservoir, which is located at approximately 1,450-meter depth. Microseismic (passive) seismic monitoring has been conducted semi-continuously since mid-2003. During this time, microseismicity has been limited to a few small microseisms on average per month (Monea et al., 2008).

In the West Pearl Queen reservoir, SNL and LANL deployed a microseismic (passive) seismic monitoring system during injection in late 2003 and early 2004. A receiver array was deployed in a nearby well and the microseisms generated during injection were recorded. Analysis of the data did not show any significant microseismic events, suggesting that the injection rate was not high enough to cause any significant fracturing (Pawar et al., 2006).

VSP and crosswell tomography were conducted at the Weyburn Field with mixed results. Although VSP provided higher resolution imaging of the reservoir zone than the surface time-lapse seismic images, it failed in the initial attempt to provide robust images of the distribution of injected CO_2. At least part of this failure was due to non-repeatability of the data. A time-lapse horizontal crosswell tomographic survey was planned at Weyburn. The baseline survey, acquired prior to the start of CO_2 injection, provided high resolution tomographic images of the reservoir zone of interest, but a follow-up survey was not successfully completed (Monea et al., 2008).

VSP was used at the Frio Brine Pilot before and after CO_2 injection, and analysis showed that the tool was successful in detecting CO_2 (Hovorka et al., 2005).

Injection Parameters – Other measurements used in the subsurface include injection volumes, rates, and pressures. These measurements have been extensively used in the oil and gas industry and easily transfer to monitoring CO_2 injection. All injection wells should be equipped with meters and pressure sensors to accurately measure injection and production rates (if applicable to the project), surface casing pressure, injection pressure, and annulus pressure to verify that no casing, tubing, or packer leaks exist. Reservoir pressure data may be accomplished either with downhole pressure sensors or by inverting surface pressure and injection data given knowledge of the injection profile. The Weyburn field, Frio Brine Pilot, and the West Pearl Queen reservoir all utilized these pressure sensors and techniques.

Cement Reactions – Cement reactions to CO_2 are also part of Core R&D. NETL, Carnegie Mellon University (CMU), and RJ Lee Group, Inc., are conducting laboratory tests to determine any adverse reactions. That knowledge is used in conjunction with other wellbore information to help determine the integrity of the well (NETL Website, 2008).

3.1.4 Enhanced Coalbed Methane Methods

An attractive option for disposal of CO_2 is sequestration in deep, unmineable coal seams. Not only do these formations have high potential for adsorbing CO_2 on coal surfaces, but the injected CO_2 can displace adsorbed CH_4, thus producing a valuable by-product and decreasing the overall cost of CO_2 sequestration. Coal can store several times more CO_2 than the equivalent volume of a conventional gas reservoir, because it has a large internal surface area. To date, only a few experimental ECBM tests involving CO_2 injection have been conducted throughout the world.

3.1.4.1 Near-Surface Monitoring Methods

Geophysics – An innovative geophysical approach, developed by BP North America, Sproule Associates, Inc., the University of California, Santa Cruz, and LBNL, is being used to assess the ability of non-seismic techniques to adequately monitor gas movement in coalbeds under CO_2 flood at considerable cost savings over more conventional seismic techniques. An aerial remote-sensing approach is using cutting-edge thermal hyperspectral imagery to test the feasibility of monitoring large surface areas for CO_2 and CH_4 seeps (NETL Website, 2008). If successful, this approach could eliminate the need for an extensive ground-based monitoring system and associated operational costs. In development for three years, this technique was used in a CBM-CO_2 storage pilot demonstration at the Deerlick Creek Field, Black Warrior Basin in Alabama, and in a ground-surface controlled leak experiment that released CO_2 and CH_4, conducted at the Naval Petroleum Reserve Site #3 in Wyoming in 2006 (NETL Website, 2008).

3.1.4.2 Subsurface Monitoring Methods

Simulations – Simulation techniques for ECBM have been under development for the past three years by BP North America, Sproule Associates, Inc., the University of California, Santa Cruz, and LBNL. The program addresses optimization of ECBM recovery using CO_2, in addition to monitoring, verification, and risk assessment of CO_2 GS in coalbeds. A numerical modeling study is using a state-of-the-art CBM simulator to define the physical and operational boundaries and tradeoffs for safe and effective CO_2 storage accompanying CO_2-ECBM recovery. Geologic and reservoir engineering data from a CO_2-CBM storage pilot demonstration at the Deerlick Creek Field, Black Warrior Basin, in Alabama were acquired, evaluated, and integrated into the reservoir simulation (NETL Website, 2008).

CONSOL and NETL onsite researchers, in collaboration with the Zero Emission Research and Technology (ZERT) team and West Virginia University, conducted the essential computational modeling and monitoring for pretest injection simulations. The simulations will enable researchers to determine reservoir properties, CO_2 injection and CBM production rates, and structural responses of the reservoir. Simulations also dictate what monitoring networks are needed to predict both the migration of CO_2 within the coal seam and the recovery of CH_4 from the coal seam (NETL Website, 2008).

3.2 Core R&D Test Locations

The majority of field projects supported by DOE are being implemented by the RCSPs. Yet, since 1999 the DOE's Core R&D Program directly supports a limited number of GS field tests throughout North America in order to contribute towards gaining the knowledge necessary to one day employ GS of CO_2 commercially across various geologic and regional settings. The program's core R&D agenda focuses on increased understanding of CO_2 GS, MVA technology and cost, and regulations through field testing of GS technologies. A major portion of DOE's Core R&D is aimed at providing an accurate accounting of stored CO_2 and a high level of confidence that the CO_2 will remain permanently sequestered. MVA research is being developed at these select Core R&D supported field tests, including the Frio Brine Pilot, West Pearl Queens Field Test, and the Weyburn Field test.

Frio Brine Pilot, Texas – The Frio Brine Pilot in Texas is a project testing MVA techniques (Hovorka et al., 2005). This is the first field test in the United States to investigate the ability of brine formations to store CO_2. Phase I of the project involved the injection of 1,600 tons of CO_2 into a mile-deep well drilled into the high porosity Frio sandstone formation. CO_2 was injected on October 4, 2004, into a brine/rock system contained within a fault-bounded compartment with a top seal of 200 feet of Anahuac shale. The site is representative of a large volume of the subsurface from coastal Alabama to Mexico and provides useful experience in the planning of CO_2 storage in high-permeability sediments throughout the world.

The project is being extensively monitored to observe the movement of the CO_2. Before injection, several monitoring techniques were executed, including baseline aqueous geochemistry, wireline logging, crosswell seismic, crosswell EM imaging, and vertical seismic profiling (VSP), along with hydrologic testing and surface water and gas monitoring. Monitoring was periodically repeated during injection and is continuing. Data gathered during this test will enable researchers to enhance conceptualization and calibrate models to plan, develop, and effectively monitor larger-scale, longer-timeframe CO_2 injections and devise risk management strategies for CO_2 storage in geologic formations of this type (Monea et al., 2008).

West Pearl Queen Field, New Mexico – This project represents a subset of saline reservoirs and depleted oil reservoirs that present both benefits and challenges in the application of MVA methodologies. The benefits include a comparatively extensive knowledge base of site-specific reservoir properties and subsurface gas/fluid rock processes developed during petroleum production operations, while the challenges include monitoring the impact of long-term CO_2 storage on the three-phase system (oil, brine, and gas).

SNL, LANL, and NETL have partnered with an independent producer, Strata Production Company, to conduct the first DOE field demonstration of CO_2 storage in a depleted oil reservoir, the West Pearl Queen Field (Pawar et al., 2006). About 2,100 tons of CO_2 was injected into the field during 2002 and 2003. Shutting the injection well for six months allowed the injected CO_2 to interact with the reservoir. The injection well was then vented to release the injected CO_2. Data acquisition included geophysical surveys, including 3-D surface seismic surveys before and after injection; microseismic (passive) seismic surveys during injection; and changes in reservoir rock properties due to CO_2 exposure, determined through laboratory examination of samples, including x-ray diffraction and scanning electron microscopy. Results of the planned integration of field and laboratory experimental results, numerical modeling, and geophysical monitoring will be beneficial in planning and implementing more complex field tests, as well as in identifying scientific and technological gaps relative to the implementation of long-term CO_2 storage in depleted oil and gas reservoirs (Monea et al., 2008).

Weyburn Field, Regina, Saskatchewan – In July 2000, a major research project to study the GS of CO_2 was launched by the Petroleum Technology Research Centre (PTRC), located in Regina, Saskatchewan, in close collaboration with EnCana Resources of Calgary, Alberta. This CO_2 monitoring and storage project was a field demonstration of CO_2 storage in the subsurface, made possible by adding a research component to EnCana's CO_2 EOR project that has been underway since 2000 at its Weyburn Unit. Located in the southeast corner of Saskatchewan in Western Canada, the Weyburn Unit is a 180 km^2 (70 mi^2) oil field discovered in 1954; production is 25 to 34 degree API medium gravity sour crude from the Midale beds of the Mississippian Charles Formation. Water flooding initiated in 1964, and significant field development, including the extensive use of horizontal wells, began in 1991.

In September 2000, EnCana initiated the first phase (Phase 1A) of a CO_2 EOR scheme in 18 inverted nine-spot patterns. The flood is to be expanded in phases over the next 15 years to a total of 75 patterns. The CO_2 is approximately 95 percent pure, and the initial injection rate is 5,000 tons/day (95 million standard cubic feet per day [scfd]). Approximately 30 million tonnes of CO_2 is expected to be injected into the reservoir over the project's life. The CO_2 is a purchased by-product from the Dakota Gasification Company's synthetic fuels plant in Beulah, North Dakota, and is transported through a 320-kilometer pipeline to Weyburn.

A broad, but not exhaustive, spectrum of monitoring techniques has been applied at Weyburn, including various seismic methods (time-lapse 3-D multi-component surface seismic, multi-component vertical seismic profiling, and microseismic (passive) seismic monitoring), magnetotellurics, production fluid sampling, geochemical analysis, tracer studies, and soil gas sampling and analysis (Monea et al., 2008).

Other Field Research Teams – ARI is evaluating the effect of slow or rapid CO_2 leakage on the environment during initial operations or the subsequent storage period. The study will include a comprehensive and multi-disciplinary assessment of the geologic, engineering, and safety aspects of natural analogs. Five large natural CO_2 fields, which provide a total of 1.5 billion ft^3/day of CO_2 for EOR projects in the United States, have been selected for evaluation. Based on the results of a geochemical analysis of CO_2 impacts and geomechanical modeling, an evaluation of environmental and safety related factors will be completed.

Battelle Memorial Institute is completed a DOE sponsored project that designed an experimental CO_2 injection well and prepare it for permitting. Tasks involved include subsurface geologic assessment in the vicinity of the experimental site, seismic characterization of the site, borehole drilling to characterize the reservoir and cap rock formations, injection and monitoring system design, and risk assessment. The well site is located at a large coal fired power plant in west-central West Virginia. The site has the advantage of providing access to both saline formations and deep coalbeds. Another benefit of the geology in the site vicinity is the formation depth of about 9,000 feet, which provides significant cap rock containment potential and separation from freshwater. The project involved site assessment to develop the baseline information necessary to make decisions about a potential CO_2 geologic disposal field test and verification experiment at the site. MVA efforts included; (1) a completed characterization of subsurface formations using 2-D seismic and evaluated the possible use of seismic technologies for monitoring and (2) completed an approximately 9,200 foot well that was designed from the outset to be capable of retrofit to an injection well.

LBNL, LLNL, Oak Ridge National Laboratories (ORNL), and their partners are developing innovative monitoring technologies to track migration of CO_2. The project, called GEO-SEQ, will develop and use seismic techniques, electrical imaging, and isotope tracers for optimizing value added sequestration technologies for brine, oil and gas, and CBM formations.

ZERT group, in conjunction with Montana State University is conducting studies at a newly-developed controlled CO_2 release facility established on the campus of Montana State University in Bozeman, Montana. The field facility was built for the intended purpose of evaluating CO_2 monitoring instrumentation and techniques in order to detect the controlled CO_2 release. The ZERT site uses a packer system capable of injecting CO_2 into several isolated and independent zones in the shallow subsurface. CO_2 flow into each zone can be controlled independently. In August 2007, a controlled release at a uniform flow rate was delivered to the six zones resulting over an eight-day period in which a total release of 0.3 tons CO_2 day. ZERT has been developing the use of laser-based instruments to detect CO_2 both above ground and in the subsurface. Both the above ground and subsurface instruments were capable of detecting CO_2 concentrations above background CO_2 levels, demonstrating the instrument's capability for carbon sequestration site monitoring (Humphries et al., 2008 & Lewicki, J. et al., 2007b).

3.3 International Projects

The DOE's Carbon Sequestration Program also supports global initiatives, such as the Carbon Sequestration Leadership Forum (CSLF), an international climate change initiative that focuses on the development of technologies to cost-effectively capture and sequester CO_2, and the International Energy Agency (IEA). The Carbon Sequestration Program is also providing technical and financial support to international projects through the Core R&D MVA Program. Projects include the Weyburn Project (see Section 3.2) in Canada, the Sleipner Project in Norway, the In Salah Project in Algeria, the CO_2SINK Project in Germany, and the Otway Basin Pilot Project in Australia.

Sleipner West (Sleipner) – The Sleipner West natural gas field in the North Sea (Norway) produces associated CO_2. To avoid paying a tax on CO_2 emitted into the atmosphere, Statoil, which owns the field, has been injecting most of the recovered CO_2 into a saline aquifer, the Utsira formation, about 1,000 meters beneath the sea in Sleipner East. The Utsira formation is a permeable sandstone saline formation about 200 to 250 meters thick overlain by mudstone. The studied site, with an average water depth of about 80 meters, covers an approximately three by seven kilometer area (Chadwick et al., 2008 & NETL, 2006). NETL has directly supported the application of microgravity surveys at the Sleipner project

In Salah – In Salah Gas is a joint venture between BP (33 percent), Sonatrach (35 percent) and Statoil (32 percent). The project comprises a phased development of eight gas fields located in the Ahnet-Timimoun Basin in Algerian Central Sahara. The initial development focuses on the exploitation of the gas reserves in the three northern fields. These gas fields contain CO_2 concentrations ranging from one to nine percent, which is above the export gas specification of 0.3 percent and, therefore, requires CO_2 removal facilities. Instead of venting the CO_2 to the atmosphere, In Salah Gas re-injects the produced CO_2 (up to 70 million scfd or 1.2 million tonnes per year) into the aquifer zone of one of the shallow gas producing reservoirs. This project is the world's first CO_2 storage operation in an actively produced gas reservoir (Riddiford et al., 2004).

CO2SINK Project – CO2SINK is a European Commission funded mid-scale (60,000 tonnes over two years) demonstration project that aims to increase the knowledge-base of CO_2 storage in saline formations and increase public confidence and awareness of GS. The CO2SINK field site is located in Ketzin, Germany, approximately 20 km west of Berlin at the site of a former natural gas storage field. Storage will be at an approximate depth of 650 meters in the saline Stuttgart Formation. The CO2SINK project deploys numerous monitoring and measurement technologies that are focused on increasing the understanding of subsurface transport of CO_2 in saline formations. In particular, the application of surface and wellbore seismic, wellbore logging, electrical resistivity tomography, geochemical sampling, and thermal logging provide a unique opportunity to compare and contrast the different measurement methods. CO2SINK incorporates a robust MVA program in order to assess the efficacy of various monitoring approaches, including several that have never before been used during a CO_2 sequestration demonstration project (Cohen and Plasynski, 2008). In 2007, LBNL began working collaboratively with GeoForschungsZentrum (GFZ), Postdam in order to collect, interpret, and disseminate selected ata sets relating to two specific tasks: (1) conducting Distributed Thermal Perturbation Sensor (DTPS) Measurements, and (2) performing laboratory measurements of seismic properties as a function of variable CO_2 saturation to facilitate accurate interpretation of field seismic data. LBNL and GFZ, Postdam are implementing the firstever DTPS study aimed at monitoring the replacement of formation brine. The DTPS unit is comprised of a fiber-optic temperature sensor and a line source heater that runs along the axis of a wellbore. The DTPS will monitor the heating and cooling phases of a thermal perturbation, in which formation thermal properties can be estimated. This technique has been successful in the past at monitoring groundwater transport, however the application to CO_2 sequestration is very new. The DTPS data is being compared to other monitoring technique data being deployed at CO2SINK (high-resolution ERT and wellbore logging). The DTPS technique offers the possibility of a simple and inexpensive measurement that can be performed periodically to assess the distribution of CO_2 within a storage field, and replace more expensive monitoring methods. To date, the DTPS has been deployed in two observation wells at the CO2SINK, Ketzin site, in which baseline data have been acquired (Cohen and Plasynski, 2008).

Otway Basin Pilot Project – The $36 million Otway Basin Pilot Project, located in southern Australia, is one of 19 sequestration projects endorsed by the CSLF. The project is directed by Australia's Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC). Project partners include DOE and a variety of other public and private organizations. The Otway Basin has a large source of natural CO_2 and an abundance of now-depleted gas fields consisting of geologic formations with a history of storage permanence. CO_2 will be produced from an existing well then compressed to a supercritical state for more efficient movement and storage at a final location. This project will allow for new insight to be gained about GS in Australia as well as improvements to MVA techniques. MVA practices at Otway include: (1) identifying an optimal suite of MVA technologies to deploy by using forward and inverse geophysical simulators, (2) deploy unique capabilities such as U-tube sampler (Appendix III), noble gas tracers, and seismic techniques, and (3) participate in integrated interpretation and simulation of the fate and transport of the injected CO_2 (Cohen and Plasynski, 2008).

3.4 Regional Carbon Sequestration Partnerships

The growing concern over the impact of CO_2 on global climate change led DOE to form a nationwide network of seven RCSPs to help determine the best approaches for capturing and permanently storing CO_2. RCSPs are tasked with determining the most suitable technologies, regulations, and infrastructure for carbon capture, transport, and storage in their respective areas of the United States and, for some partnerships, portions of Canada. The seven partnerships include more than 350 state agencies, universities, national laboratories, private companies, and environmental organizations, spanning 42 states and four Canadian provinces. The seven RCSPs created under the DOE program are:

- Big Sky Carbon Sequestration Partnership (Big Sky)
- Midwest Geological Sequestration Consortium (MGSC)
- Midwest Regional Carbon Sequestration Partnership (MRCSP)
- Plains CO_2 Reduction Partnership (PCOR)
- Southeast Regional Carbon Sequestration Partnership (SECARB)
- Southwest Regional Partnership on Carbon Sequestration (SWP)
- West Coast Regional Carbon Sequestration Partnership (WESTCARB)

The RCSP initiative is being implemented in three phases: Phase I, known as the Characterization Phase (2003 to 2005), focused on collecting data on CO_2 sources and sinks and developing the human capital to support and enable future carbon sequestration field tests (Litynski et al., 2006a); Phase II, known as the Validation Phase (2005 to 2009), focuses on implementing small-scale field tests using storage technologies; and Phase III, known as the Development Phase (2008 to 2017) involves developing large-scale (1 million tones or more of CO_2) CCS projects, which will demonstrate that large volumes of CO_2 can be safely, permanently, and economically injected into geologic formations representative of formations with large storage capacity. Currently, the partnerships are conducting over 20 small-scale geologic field tests and 11 terrestrial field tests (Litynski et al., 2006a,b). Each field test incorporates extensive characterization, permitting, reservoir modeling, site monitoring, risk assessment, public outreach, and technology transfer efforts aimed at ensuring safe and permanent carbon storage and wide dissemination of the information developed (NETL Website, 2008).

To overcome the challenges associated with MVA, RCSPs are developing technologies for cost-effective instrumentation and protocols that accurately monitor carbon storage, protect human and ecosystem health, and improve computer modeling for CO_2 plume tracking. The monitoring activities that occurred during all three phases are described in Section 3.5.

3.5 Applicable Core R&D, International, and Regional Carbon Sequestration Partnership Program Monitoring Efforts

Applicable Core R&D projects, RCSP projects, and international projects are referenced in the discussion of monitoring methods below.

3.5.1 Simulation

Following site characterization, working hypotheses about important mechanisms that control the behavior of injected CO_2 are developed and tested. This approach has been studied extensively over the last decade from a risk assessment perspective (Savage et al., 2004; Lewicki et al., 2006). The mechanisms that have controlled past behavior, and will control future behavior, need to be understood through fluid flow simulation based on an understanding of the fluid and chemical processes active at the pore level and guided by available injection/production and monitoring data. Simulations are utilized to predict the following: temporal and spatial migration of the injected CO_2 plume; the effect of geochemical reactions on CO_2 trapping and long-term porosity and permeability; cap rock and wellbore integrity; the impact of thermal/compositional gradients in the reservoir; pathways of CO_2 out of the reservoir; the importance of secondary barriers; effects of unplanned hydraulic fracturing; the extent of upward migration of CO_2 along the outside of the well casing; impacts of cement dissolution; and consequences of wellbore failure.

Simulation is a critical step in the systematic development of a monitoring program for a GS project, because selection of an appropriate measurement method and/or instrument is based on whether the method or instrument can provide the data necessary to address a particular technical question. Effective monitoring can confirm that the project is performing as expected from predictive models. The linkage between model results and monitoring data can be complicated if monitoring programs are not designed to address which parameters should be monitored, timing of measurements, location, spatial scale, and resolution of measurements to match with model parameters. This is particularly valuable in the early stages of a project when the opportunity exists to alter the project to ensure long-term storage and improve efficiency. Monitoring data collected early in the project are often used to refine and calibrate the predictive model, improving the basis for predicting the longer-term performance of the project.

Simulations have been used in Core R&D test projects, including Weyburn, Frio Brine Pilot, and West Pearl Queen (see Section 3.2), and at Deerlick Creek and in Marshall County, West Virginia, for ECBM (see Section 3.1.4). Several modeling programs have been used by SECARB, WESTCARB, and MRCSP. SECARB has used Comet3, a reservoir simulator, to determine the precise location of the observation wells for a CBM project in the Black Warrior basin. WESTCARB, working with the Arizona Utilities CO_2 Storage Pilot demonstration, will conduct preliminary computer simulations (by LBNL) using TOUGH2/EOS7C in support of the pilot tests. The simulations will be used to determine:

- CO_2 quantity and rate of injection.
- The expected pressure and temperature changes in the reservoir associated with the injection.
- The kind of monitoring and sampling that should be conducted in the injection well.

CO_2 storage simulations for the Mt. Simon formation in west-central Ohio near the TAME Ethanol site have been carried out in earlier research by members of the MRCSP team. While these early models did not simulate the exact location as the proposed projects, the results are similar to what may be expected for these general areas. Key input parameters in the simulations were based on best available regional data. The parameters are not site specific, but they are fairly reasonable for the Mt. Simon formation in the area. These initial model studies indicate that injection rates over 1 million tons of CO_2 per year may be sustained in the Mt. Simon formation at the TAME site.

Several types of reservoir simulators being used by the RCSPs' large-scale field projects are important for sequestration of CO_2 in brine-saturated formations or sequestration in formations that contain both brine and oil and are briefly described in Table 3-1. These include simulators for multiphase flow through porous media, geomechanical simulators, simulators for "leakage" of CO_2 from wells or from deep underground back to the atmosphere, and simulators for flow through fractured geologic formations. Many of the simulators are used to predict underground multi-phase flow, flows to the surface, geomechanical computation, or flow through fractured media. For historical reasons, the phrases "reservoir simulator" and "reservoir simulation" often refer, respectively, only to computer codes and calculations that treat the flow of fluids deep underground.

In general, three key areas of simulation – focusing on faults/fractures, subsurface behavior and fate of CO_2, and geomechanical/mechanical/flow models – demonstrate how simulation technology is critical to sequestration evaluation and risk assessment.

3.5.2 Geophysical Approaches

Single or multi-component 2-D and 3-D surface seismic surveys are a widely deployed technology in oil and gas exploration that utilizes surface sources (e.g., dynamite or vibrating machines) to generate downward propagating elastic waves that are reflected from subsurface features and return to the surface where they are recorded by ground motion sensors (geophones). In the case of a 3-D survey, a regular 2-D grid of surface sources and sensors is deployed. The data recorded in this manner is combined to produce a 2-D or 3-D image of the subsurface. In a monitoring program, an initial seismic survey contributes to geological site characterization. In addition, the survey provides an initial baseline survey that can be compared to subsequent seismic surveys to create a time lapse image of CO_2 plume migration and to detect significant leakage and migration of CO_2 from the storage site. International projects, including Sleipner, CO_2SINK, and Weyburn, and selected RCSP demonstration projects (MRCSP and SWP) are using surface seismic surveys (Figures 3-1, 3-2, and 3-3). The Weyburn project is one example of a Core R&D project that is implementing seismic profiling. Seismic studies at small CO_2 test injections (e.g., Frio [crosswell seismic] and Hobbs) demonstrate that seismic reflection is sensitive to plumes as small as a few thousand tons.

Table 3-1: Classification of Primary Models Used by RCSPs

Type of Code	Names	Main Sequestration Application
Geomechanical	GMI-SFIB, ABCUS	Modeling stresses applied to reservoirs during and after injection
Non-isothermal multi-phase flow in porous media	Eclipse, GEM-GHG, NUFT	Model plume dispersion
Non-isothermal multi-phase chemically reactive flow in porous media	PFLOTRAN, STOMP	Model plume dispersion and CO_2 interaction with reservoir fluids
Non-isothermal multi-phase flow in porous media with geomechanical coupling	TOUGH-FLAC	Model plume dispersion and impact of stresses due to CO_2 interactions
Non-isothermal multi-phase flow in porous media with reactive geochemistry	TOUGHREACT, VIP Reservoir	Model plume dispersion and CO_2 trapping
Flow in fractured media	NFFLOW-FRACGEN	CO_2 flow through fractured networks

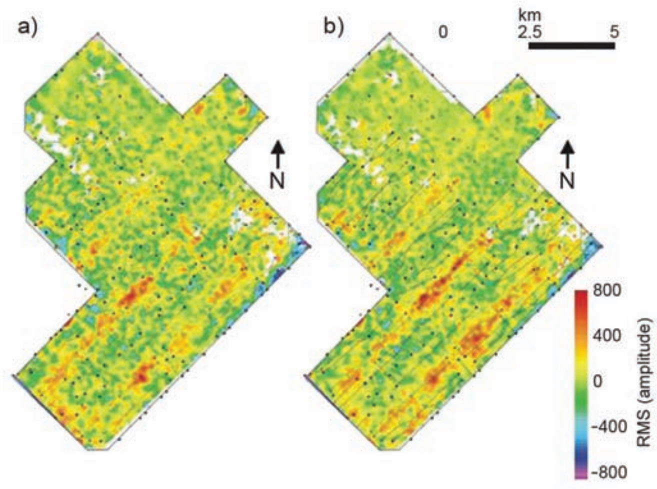

Figure 3-1: Amplitude difference map at the Midale Marly horizon for the Weyburn Monitor 1 (a) and 2 (b) surveys relative to the baseline survey. The normalized amplitudes are RMS values determined using a 5-ms window centered on the horizon.

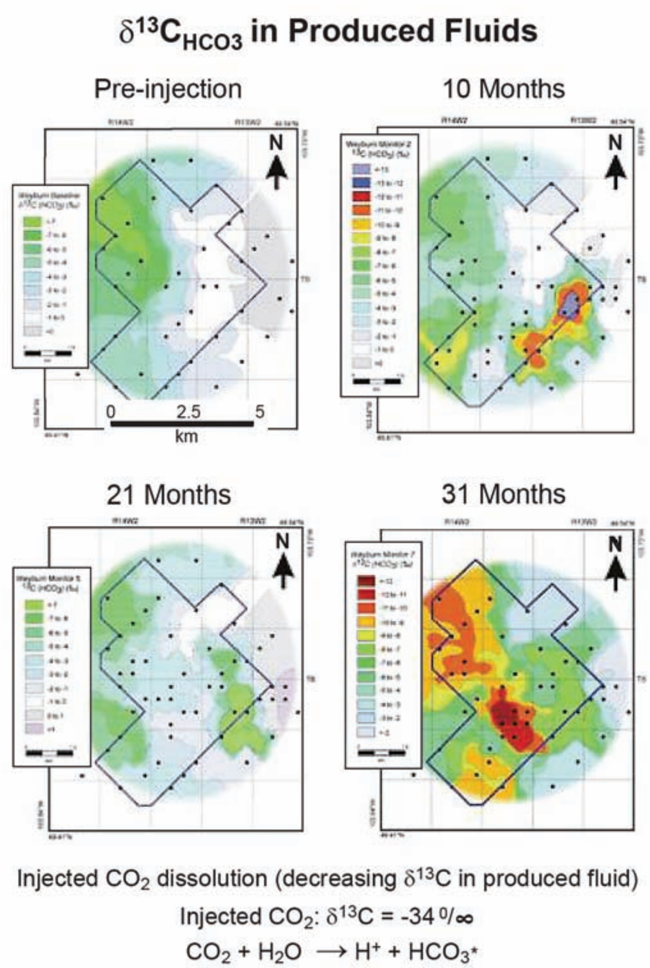

Figure 3-2: $\delta^{13}C$ {HCO_3} in produced fluids at Weyburn. The well locations (black dots) represent the locations of data points that are used to produce the contour plots. Values are per mil differences in the ratio of ^{12}C to ^{13}C relative to the PDB standard.

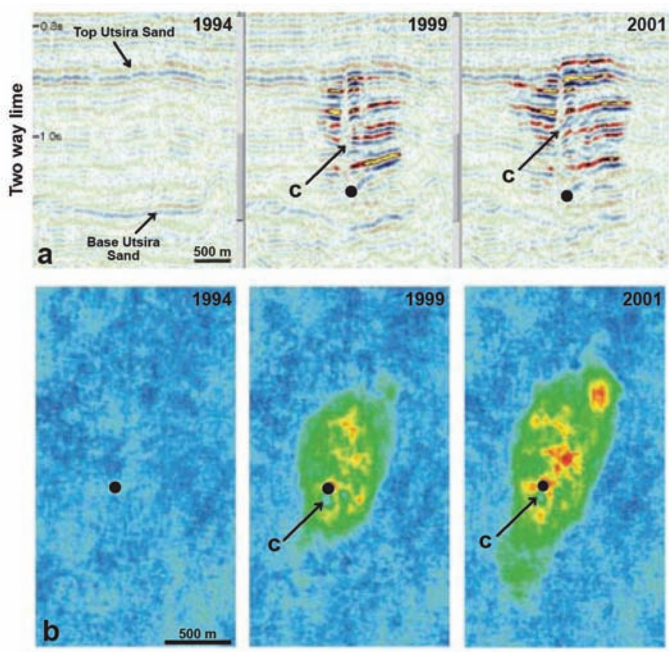

Figure 3-3: Time lapse seismic data collection and interpretation from large CO_2 injection projects. Three successive seismic volumes from the Sleipner project, Norway. Upper images are cross-sections through the injection point; the lower images show impedance changes at the top of the CO_2 plume. Injection began in 1996, between the first two surveys. From Arts et al. (2004).

VSP techniques provide information in the vicinity of the borehole. VSP is a class of seismic measurements that can obtain high resolution images near the wellbore (Hardage, 2000). VSP acquisition utilizes sensors deployed within a borehole and sources located at the surface, whereas crosswell tomography uses sources and receivers both deployed in boreholes. The advantage of VSP, crosswell seismic, and other high resolution methods is to obtain more precise estimations of the CO_2 induced effects on seismic properties. Results from high resolution testing can be used as a calibration for lower resolution surface seismic. A potential advantage of these borehole methods, relative to surface seismic methods, is higher vertical resolution imaging. This approach has been deployed and tested at the Frio Brine Pilot project to characterize the reservoir and to monitor CO_2 movement (Hovorka et al., 2005). At Weyburn VSP provided higher resolution imaging of the reservoir zone than the surface time-lapse seismic images. However, due to non-repeatability, the VSP failed to provide images of the distribution of injected CO_2. Core R&D test projects using geophysical monitoring methods include Weyburn, Frio Brine Pilot, and West Pearl Queen (see Section 3.2). VSP will be used by RCSPs (MRCSP, SECARB, SWP, and WESTCARB) during their Phase II projects to evaluate cap rock integrity in the vicinity of the CO_2 injection well. VSP can be implemented in a "walk-away" fashion in order to monitor the footprint of the plume as it migrates away from the injection well. Walk-away VSP is employed by placing the source progressively further and further down-gradient from the injection well in order create an offset at the surface as the receivers are held in a fixed location. This technique yields a mini 2-D seismic line that can be of higher resolution than surface seismic data and provides more continuous coverage than an offset VSP. Furthermore, walkaway VSPs with receivers placed above the reservoir can be an effective method to quantify seismic attributes and calibrate surface seismic data.

Microseismic arrays were tested at Weyburn and are currently installed and collecting data at In Salah. In general, microseismic tools work best in areas with moderate permeability and where rock formations contain abundant natural fractures. RCSPs employing microseismic technology include MRCSP, PCOR, and SECARB. In general, no significant activity has been observed at Australia's Otway project, as part of DOE funded GEO-SEQ project, regarding the use of microseismic arrays.

3.5.3 Crustal Deformation

Injection of large fluid volumes into the shallow crust causes surface deformation that can be measured. This information can help to identify the location and volume of subsurface CO_2, detect anomalous shallow build-ups, and provide operational and hazard information. Two techniques are commonly used to measure deformation: tiltmeters and synthetic aperture radar. The CONSOL project in West Virginia is an example of one of the Core R&D projects using tiltmeters. Several RCSPs have proposed employing tiltmeter surveys in their monitoring programs, including MRCSP (Mt. Simon reservoir, TAME site), PCOR, SECARB, and SWP (San Juan Basin ECBM project – under Core R&D).

3.5.4 Geochemical Methods

When CO_2 dissolves in water, a number of geochemical changes occur. These can be due to direct effects (e.g., formation of carbonic acid) or indirect effects (e.g., mineral dissolution). In addition, chemicals can be injected with CO_2 and used as tracers in the subsurface. Geochemical monitoring and analysis have been used routinely in oil field operations. Several important sequestration projects have deployed geochemical surveys to monitor CO_2 location and fate, including Weyburn (Hirsch et al., 2004), CO2SINK (Cohen and Plasynski, 2008), West Pearl Queen (Wilson et al., 2007), and the Frio Brine Pilot (Doughty et al., 2004). In these applications, the surveys considered for hazard management and to provide some insight into processes at depth.

Tracers have been used at Weyburn (Core R&D and international project) and the Frio Brine Pilot, as well as by several RCSPs (MRCSP, SECARB, SWP, and WESTCARB). Core R&D test projects using groundwater monitoring methods include Weyburn, the Frio Brine Pilot, and West Pearl Queen (see Section 3.2).

3.5.5 Surface Monitoring

Common field applications in environmental science include the measurement of CO_2 concentrations in soil air, including the flux from soils. Diffuse soil flux measurements are made using simple infrared (IR) analyzers. Closed chambers can be used to measure the flux into and out of the soil, including CO_2. The gases measured this way can be collected and analyzed isotopically to understand their origin. This method has been developed and field tested to monitor CO_2 injections at the Rangely Field in northwestern Colorado (Klusman, 2003).

As part of the Core R&D Program, the California Institute of Technology developed an open-path device that uses a laser to detect CO_2 (Section 3.1.1). Researchers at Montana State University have developed instruments for carbon sequestration site monitoring based on tunable laser spectroscopy. These instruments utilize continuous wave temperature tunable distributed feedback diode lasers that are capable of identifying several CO_2 absorption features. These instruments are being employed at the ZERT field site located in Bozeman, Montana. As mentioned in Section 3.2, the ZERT project is investigated the ability of the lasers to detect CO_2 above background levels in the atmosphere and subsurface by conducting a controlled release of CO_2 from the ground surface. Laser instruments were successful in detecting significant variations from background CO_2 levels in both the atmosphere and subsurface after CO_2 had been injected and subsequently released, indicating that the instrument is capable for use in carbon sequestration site monitoring (Humphries et al., 2008 & Lewicki, J et al., 2007b).

Additionally, LANL has developed CO_2 monitoring instruments that detect O_2/CO_2, as well as developing radon (^{222}Rn) detectors. These secondary technologies are described in Appendix II. RCSPs using near-surface gas monitoring techniques for Phase II and Phase III projects include MRCSP, SECARB, SWP, and WESTCARB.

4.0 Review of EPA Permitting Requirements

Existing regulations in the United States relevant to GS of CO_2 involve protection of groundwater meeting underground sources of drinking water (USDW) standards from brine and CO_2 plume infiltration (from the CO_2 injection process) under the UIC Program. The UIC Program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal (http://www.epa.gov/safewater/uic/index.html). Once EPA promulgates final regulations for GS wells for states and at the Federal level, proper criteria and standards will be in place to ensure a consistent and effective permitting system for commercial-scale GS projects.

EPA has proposed regulatory changes to the UIC Program and invites the public and stakeholders to provide input throughout the rule development process (Federal Register, July 25, 2008). The UIC Program provides standards, technical assistance, and grants to state governments for regulating injection wells and protecting drinking water resources. At present, EPA defines the five classes of wells (Classes I to V) according to the type of fluid they inject and where the fluid is injected. EPA is proposing to create a new category of injection well under its existing UIC Program with new Federal requirements to allow for permitting of the injection of CO_2 for the purpose of GS. The proposal builds on existing UIC regulatory components for key areas including siting, construction, operation, monitoring and testing, and closure for injection wells that address the pathways through which USDWs may be endangered. In addition to protecting USDWs, the proposed rule provides a regulatory framework to promote consistent approaches to permitting GS projects across the United States.

EPA has promulgated regulations for siting, drilling, completing, operating, monitoring, and closing each of the existing injection well classes. A detailed discussion of the five existing UIC well classes is available on EPA's UIC website (http://www.epa.gov/safewater/uic/wells.html).

Federal and state agencies have permitted the wells for the RCSP Program's Validation Phase field projects across various geologic sink formations under the UIC Program's current regulatory framework for the five well classes (with a sixth class proposed in July 2008). The wells are classified under the following five categories:

- Class I – Wells injecting hazardous, industrial, and municipal wastes below USDWs.
- Class II – Wells related to oil and gas production, mainly injecting brine and other fluids.
- Class III – Wells injecting fluids associated with solution mining of minerals, such as salt (sodium chloride [NaCl]) and sulfur (S).
- Class IV – Wells injecting hazardous or radioactive wastes into or above USDWs; generally only used for bio-remediation.
- Class V – Injection wells not included in Classes I through IV that are typically used as experimental technology wells.
- Class VI – Proposed new class of injection well specific for GS of CO_2 (Section 4.3 and Table 4-2).

Currently, wells for GS of CO_2 fall under Classes I, II, and V. The proposed EPA rulemaking, when finalized, would establish a new class of injection well – Class VI – for GS projects based on the unique challenges of preventing potential endangerment to USDWs and leakages from the subsurface from these operations (Federal Register, July 25, 2008, p 43502). The variations in the current permitting process and well classification reflect differences in project type, institutional architecture, primacy, and the local regulations of individual states or provinces within the context of overall Federal oversight.

EPA has been actively working with DOE's R&D Program to evaluate potential impacts on health, safety, and the environment through coordinating efforts like Program Guidance #83, "Using the Class V Experimental Technology Well Classification for Pilot GS Projects." The guidance is intended to assist state and EPA regional UIC Programs in processing pilot permit applications for projects designed to assess the efficacy of CO_2 injection for the purpose of GS (http://www.epa.gov/safewater/uic/wells_sequestration.html).

Of the five well classes, EPA believes that the Class V experimental technology well subclass provides the best mechanism for authorizing and permitting CCS pilot projects. Class V experimental technology wells are intended to demonstrate unproven but promising technologies. On the other hand, wells that inject CO_2 for the purposes of EOR and enhanced gas recovery (EGR) are designated as Class II wells. While there are similarities between CO_2 injected for oil and gas extraction and for CCS, EPA believes that there are also important differences that require the creation of a new class of injection well. For example, CO_2 injection for CCS will eventually involve much greater volumes that will require containment for hundreds of years.

Additional regulatory guidance by the Interstate Oil and Gas Compact Commission's (IOGCC) Task Force on Carbon Capture and GS led to producing a legal and regulatory model framework for the GS of CO_2 that addresses the unique requirements of individual states and Canadian provinces. The 30 member states and four Canadian member provinces have jurisdiction, experience, and expertise in the regulation of oil and natural gas wells (Class II), particularly in the injection of petroleum wastes and CO_2 for EOR. In addition, natural gas storage statutes provide a starting point for operational plans addressing public health and safety during injection. The IOGCC model rules are subject to revision as they are reviewed by more people and more knowledge about geological sequestration is developed. Although custody issues for long-term GS are not addressed in its report, IOGCC's work is a first step in considering appropriate regulatory requirements.

The EPA proposed rules use a combination of fixed timeframe and a performance standard. EPA is tentatively proposing a post-injection site care (monitoring) period of 50 years with the UIC Program Director having discretion to change that period to lengthen or shorten the 50 year period if appropriate. The default timeframe could be lengthened if potential for endangerment to USDWs still exists after 50 years or if modeling and monitoring results demonstrate that the plume and pressure front have not stabilized in this period. Conversely, the 50-year time period could be reduced if data on pressure, fluid movement, mineralization, and/or dissolution reactions support a determination that movement of the plume and pressure front have ceased and the injectate does not pose a risk to USDWs. This combination of fixed timeframe and performance standard emphasizes the importance of developing robust technologies for measurement and monitoring of CO_2 stored in deep geologic formations.

4.1 RCSP Project UIC Classification Summary

One of the goals of the RCSP large-scale field projects is to not only develop the necessary technologies, but also to contribute to progress in the development of permitting requirements. Validation and Development Phase projects require permits for well drilling and injection that are enforced by Federal (i.e., EPA or Bureau of Land Management [BLM]) and state governments and other organizations, such as the Navajo EPA, although the overall permitting process is ongoing and in flux. Nevertheless, RCSP field projects have initiated the administrative activity necessary to develop the framework for validating and potentially deploying GS of CO_2 as a GHG mitigation option.

Federal and state agencies have permitted the wells for Validation Phase field projects across various geologic sink formations under UIC Classes I, II, and V. The variations in the permitting process and well classification reflect the differences in project type, target formation characteristics, institutional architecture, primacy, and the local regulations of individual states or provinces within the context of overall Federal oversight. Almost 80 percent of the wells for Phase II projects were permitted by state agencies under the UIC Program, while 20 percent were permitted by Federal agencies. Applications for nearly all of the large-scale Development phase UIC permits will be as Class V wells. Table 4-1 presents a breakdown of the RCSPs' Validation and Development Phase UIC permits by sink type.

Table 4-1: Breakdown of RCSP (Phase II and Phase III) UIC Permits by Sink Type (as of April, 2008)

	Oil & Gas	Coal	Saline	Total
Class I			1	1
Class II	11	5		16
Class V			14	14
Total	11	5	15	31

Appendix V provides a detailed list of the target formation, sink type, injection volume and depth, UIC permit class, and the permitting agency for each RCSP project (Phase II and Phase III). Typical UIC permits for Classes I and V wells include the Archer Daniels Midland Company's Permit (Illinois Environmental Protection Agency, 2008) and the Core Energy, LLC Permit (EPA, 2007) respectively.

4.2 UIC Mandatory Requirements

The UIC Program, authorized under Part C of the SDWA, regulates the injection of fluids (including liquids, gases, and semi-solids) into the subsurface in order to protect USDWs. The UIC Program's primary mission is to protect USDWs, and no injection operations may endanger USDWs or the health of persons.

The UIC mandatory (primary) regulations and program elements reflect the ways in which injection activities could potentially endanger USDWs. Each injection well class is subject to siting, construction, operating, monitoring, and closure requirements that address the types of fluids injected and the use of the wells. For example, injection wells are sited in geologically suitable areas and a study is conducted to determine whether any conduits (e.g., abandoned wells) for fluid movement to USDWs exist. Injection wells are constructed of materials that can withstand exposure to injected fluids; operating requirements and testing throughout the injection operations help assure that the well remains in proper working order and that no unintended movement occurs. Finally, injection wells must be closed in a manner that prevents the well from inadvertently serving as a conduit for future fluid migration.

Three classes of injection wells covered in Section 4.1 (Class I, Class II, and Class V) offer potential technical analogues for GS. In general, Class I wells are subject to more stringent requirements than Class II and Class V wells. However, all EPA well classes must meet the non-endangerment of USDW standard. Table 4-2 briefly summarizes the requirements for Class I, Class II, and Class V wells. Monitoring requirements for each well class typically remain the same across the different phases (pre-operation, operation, closure, or post-closure) of the project, but vary in monitoring frequency, depending on the project phase.

Although there are no Federal requirements written specifically for Class V experimental technology wells, the EPA has issued a guidance document in 2007 that applies to GS projects that are to be permitted as Class V experimental technology wells. It provides suggested guidelines for permitting and operating near-term pilot GS projects prior to commercial-scale implementation of GS. It is designed to provide a timely and consistent framework to assist regional and state directors to permit pilot CO_2 injection wells. The guidance does not, however, substitute for the SDWA or EPA's UIC regulations; nor is it a regulation itself. Thus, it cannot change or impose legally binding requirements on EPA, states, or the regulated community, and may not apply to a particular situation based upon the circumstances. The suggested guidance makes Class V requirements for monitoring nearly as stringent as Class I UIC regulations (EPA, 2007).

Currently, all CO_2 injection in the United States is conducted in Class I, Class II, or Class V experimental technology wells. CO_2 injection into Class II wells is limited to EOR/EGR operations; when oil and/or gas recovery is complete, this classification would no longer apply. To date, all pilot-scale GS operations have been permitted as Class V experimental technology wells.

4.3 EPA's 2008 Proposal for Developing New Requirements for CO_2 Injection for GS

EPA recently announced proposed regulations to establish a path for commercial geologic carbon sequestration (Federal Register, July 25, 2008, p 53492). Once completed and adopted, the regulations will ensure there is a consistent and effective permit system under the SDWA for commercial-scale GS projects. EPA (Federal Register, July 25, 2008, p 53492) has proposed regulatory changes to the UIC Program and has invited the public and stakeholders to provide input via the rule development process.

The proposed plan is to establish a new class of injection well – Class VI – and technical criteria for geologic site characterization; Area of Review (AoR) and corrective action; well construction and operation; mechanical integrity testing (MIT) and monitoring; well plugging; post-injection site care; and site closure for the purposes of protecting USDWs. The elements of this proposal are built upon the existing UIC regulatory framework, with modifications based on the unique nature of CO_2 injection for GS.

Table 4-2: Summary of Current Mandatory Technical Requirements for Class I, Class II, Class V, and Class VI (Proposed) UIC Injection Wells

	Class I[1] and Class V[2]	Class II	Class VI
Siting	Demonstrate the presence and adequacy of injection and confining zones by presenting information on the local geologic structure and faults; geomechanical information; and maps and cross sections of the regional geology.	Demonstrate the presence and adequacy of injection and confining zones by presenting information on geologic formations; map of the injection well and AoR3; and maps, cross sections and a list of penetrations into the injection zone geomechanical information; and maps and cross sections of the regional geology.	Extensive site characterization needed, including well logs, maps, cross-sections, USDW locations, determine injection zone porosity, identify any faults, and assess seismic history of the area.
Fluid Movement	No fluid movement to a USDW[4], except for municipal wells, injectate is treated.	No fluid movement to a USDW.	No fluid movement to a USDW.
AoR	Define the AoR as a radius of at least 1/4 mile or calculate by a formula; identify and address any improperly completed or abandoned wells in the AoR.	Define the AoR as a radius of at least 1/4 mile or calculate by a formula; identify and address any improperly completed or abandoned wells in the AoR.	Determined by computational model and reevaluated during project duration.
Construction	Wells must have at least 2 layers of casing and cement in a multilayer design, with surface casing cemented to the surface, in addition to tubing and a packer. Engineering designs must be approved by regulatory agency. Tests performed during drilling to ensure no vertical migration of fluid.	Wells must be cased and cemented to prevent movement of fluids into or between USDWs	Two layers of corrosion-resistant casing required and set through lowermost USDW. Cement compatible with subsurface geology.
Operation	Injection pressures may not initiate or propagate fractures into the confining zone or cause fluid movement into USDWs. Quarterly reporting on injection, injected fluids and monitoring of USDWs within the AoR. Must report changes to facility, progress on compliance schedule, lose of mechanical integrity, or noncompliance with permit conditions. Permit valid for 10 years.	Injection pressures may not initiate or propagate fractures into the confining zone or cause fluid movement into USDWs. Make monthly observations of injection pressure, flow rate, and cumulative volume.	Injection pressures may not initiate or propagate fractures into the confining zone or cause fluid movement into USDWs. Quarterly reporting on injection, injected fluids and monitoring of USDWs within the AoR. Must report changes to facility, progress on compliance schedule, lose of mechanical integrity, or noncompliance with permit conditions. Permit valid for 10 years.

	Class I[1] and Class V[2]	Class II	Class VI
MIT[5]	Conduct internal and external MITs every five years.	Conduct internal and external MITs every five years. May use cement records as an alternative.	Continuous internal integrity monitoring and annual external integrity testing.
Monitoring	Analyze injectant; continuously monitor annular pressure; monitor for fluid movement into USDWs within AoR; conduct ambient groundwater monitoring	Analyze injectant	Analyze injectant. Continuous temperature and pressure monitoring in the target formation. Plume tracking required.
Closure	Ensure that the well ins in a state of static equilibrium, plug with cement; tag well, test plugs, submit plugging and abandonment report	Ensure that the well ins in a state of static equilibrium, plug with cement; tag well, test plugs, submit plugging and abandonment report	50 day notice and flush well. Must be plugged to prevent injectent from contaminating USDWs.
Proof of Containment and Post-Closure Care[6]	Site dependant – typically 30 years post-injection care.	Site dependant – typically 30 years post-injection care.	Post-closure site care for 50 years or until proof of non endangerment to USDWs demonstrated.
Financial Responsibility	Trust fund, surety bond, financial test, insurance or corporateguarantee that meets estimate cost of post-closure plan.	Trust fund, surety bond, financial test, insurance or corporateguarantee that meets estimate cost of post-closure plan.	Periodically update the cost estimate for well plugging, post injection site care and site closure, and remediation to account for any amendments to the area of review and corrective action plan. EPA is also proposing that the owner or operator submit an adjusted cost estimate to the Director if the original demonstration is no longer adequate to cover the cost of the injection well plugging, post-injection site care, and site closure.

Source: 40 CFR, Parts 144 and 146.

Note: This table provides an brief overview of the mandatory requirements for Class I, II, and V wells. Complete information on geologic storage of CO_2 in wells can be found at the UIC website at http://www.epa.gov/OGWDW/uic/wells_sequestration.html

[1] Class I wells have additional requirements for hazardous waste wells (Annual MIT Required), which are not covered in this table

[2] Class V wells may have additional requirements for motor vehicle waste disposal wells, which are not covered in this table.

[3] "AoR" is the Area of Review surrounding the well.

[4] USDW is an Underground Source of Drinking Water

[5] MIT is a Mechanical Integrity Test

[6] No-migration petition demonstration (fluids remain in injection zone for 10,000 years) required for Class I Hazardous wells. See Section 5.4 for discussion.

EPA-proposed monitoring efforts for the Class VI injection well are similar, in many cases, to existing UIC regulation. However, several additional monitoring requirements have been proposed for Class VI wells that exceed existing UIC regulation, including; siting requirements, AoR determination, well design and construction, MIT, tracking plume location, and post-closure care. Additional siting requirements to the existing UIC regulations include providing data on target formation porosity, information on the seismic history of the site and in-situ fluid pressures, and extensive geochemical data on fluids in the injection zone, confining zones, overburden layers and USDWs. Additional siting requirements can be fulfilled with many Primary Technologies, including wireline logs, sample cores, downhole pressure monitors, and fluid sampling.

The proposed AoR determination procedure for Class VI requires extensive computational models designed for the specific site conditions and injection regime to assess potential plume migration and pressure propagation, as opposed to relying on a one-fourth mile fixed radius around the injection well location. The models should be based on site characterization data collected regarding the injection zone and confining system, taking into account any geologic heterogeneities, and potential migration through faults, fractures, and artificial penetrations. In addition, the proposal would require that the owner or operator periodically reevaluate the AoR during the injection operation as site conditions may change from the baseline state and directly impact AoR.

Well construction procedures for Class VI wells would require that surface casing for GS wells be set through the base of the lowermost USDW and cemented to the surface. The long-string casing would be cemented in place along its entire length. GS wells would also be constructed with a packer that is set opposite a cemented interval. Also, the use of corrosion-resistant materials that are compatible with the injectate and subsurface fluids is required. MIT of the wells would require owners or operators of Class VI GS projects to monitor internal mechanical integrity of their injection wells by continuously monitoring injection pressure, flow rate, and injected volumes, as well as the annular pressure and fluid volume to assure that no anomalies occur that may indicate an internal leak. Continuous internal mechanical integrity monitoring of GS project injection wells, instead of periodic testing (which is required for most other types of deep injection wells) is important because the corrosive nature of GS waste streams makes immediate identification of corrosion-related well integrity loss critical. The proposal would also require automatic downhole shut-off mechanisms in the event of an mechanical integrity loss. The proposal would require owners or operators of CO_2 wells to demonstrate injection well external mechanical integrity (accomplished through the use of down-hole geophysical logs or surveys designed to detect such leaks) at least once annually. This increase in testing frequency (from once every five years to once a year) is justifiable for the protection of USDWs.

EPA considers CO_2 plume and associated pressure front monitoring to be necessary for verification of model predictions. The proposal requires owners or operators to track the subsurface extent of the CO_2 plume and pressure front using pressure gauges in the first formation overlying the confining zone or using indirect geophysical techniques or other downhole CO_2 detection tools, monitor for geochemical changes in subsurface formations, and if directed, monitor at the surface. Current UIC regulations only require certain operational monitoring practices (flow rate, injection pressure, etc.) (Same operational monitoring required for Class VI) and prevention of USDW contamination.

One of the major differences between current UIC monitoring regulations and Class VI proposal is the post-closure monitoring requirements. Today's proposal would also require that owners or operators: 1) develop a post-injection site care and closure plan, 2) monitor the site following cessation of the injection activity, and 3) plug all monitoring wells in a manner that prevents movement of injection or formation fluids that could endanger a USDW. Post-closure care includes recording certain formation pressures and determining location of the plume front. EPA is tentatively proposing a post-injection site care (monitoring) period of 50 years with Director's discretion to change that period to lengthen or shorten the 50-year period if appropriate (Federal Register, July 25, 2008, p 43540).

5.0 Addressing the Objectives and Goals of Monitoring

The principal goal of DOE's Carbon Sequestration Program is to gain scientific understanding of carbon sequestration options and provide cost-effective, environmentally sound monitoring technologies and accounting protocols. The goals set for GS are that by 2008, MVA protocols are sufficiently accurate so that 95 percent of stored CO_2 can be credited as net emissions reduction and by 2012, 99 percent can be credited. It is believed that the 2008 goal for MVA to accurately measure 95 percent of the amount of CO_2 retained in geologic formations has already been met or exceeded (NETL, 2007b). A 95 percent credit means that at least 95 percent retention is assured and implies that leakage rates to the atmosphere and shallow subsurface are between 0.01 and 0.001 percent per year (90 to 99 percent retention over a 1,000-year period) (Hepple and Benson, 2004). The IPCC Special Report concluded that at least 99 percent retention is likely for well selected and managed sites (Metz et al., 2005).

5.1 Role of Primary Technologies

The monitoring objectives outlined by the UIC regulations in 40 CFR § 146 are aimed at ensuring that storage projects are carefully designed and that measures are undertaken to mitigate leakage pathways so that CO_2 remains entirely in the subsurface over significant time spans (hundreds to thousands of years). The primary technologies listed in Table 5-1 are fully capable of meeting and exceeding the UIC monitoring requirements of 40 CFR § 146 and achieving the MVA goals for GS (Litynski et al., 2008). MVA technologies (Table 5-1) are aimed at assessing CO_2 storage efficiency within the target reservoir, protecting against environmental health and safety impacts associated with injection and storage, and addressing possible leakage situations. A wide array of advanced monitoring technologies has also been used/evaluated by the Weyburn Project, the Frio Project, Sleipner, and DOE's RCSP Program, as discussed at the end of this chapter. This additional monitoring was guided by the ongoing complexities of injection and storage and the results showed that CO_2 remained entirely in the subsurface over significant time spans.

Primary Technologies are considered proven technologies capable of satisfying the monitoring requirements under UIC regulations for Class I (non-hazardous), Class II, and Class V injection wells and that could be used in meeting the 95 percent and 99 percent demonstrated CO_2 containment goals for CCS projects for 2008 and 2012, respectively. These technologies are typically well-known and been effectively used in applications similar to GS, including for oil and natural gas exploration and geological subsurface characterization.

5.2 Role of Secondary MVA Technologies

Secondary technologies are typically routine, often low-cost, technologies that have been applied in other applications, such as oil field monitoring or environmental remediation. These technologies often help in the characterization of a storage formation and the overlying strata to support the development of site specific reservoir simulations and provide information on the design of the GS project. The use of these technologies for CO_2 monitoring shows promise, but the technologies require additional demonstration that they are sufficiently precise and quantitative to detect, locate, and quantify emissions from a CCS project for an appropriate monitoring program. If a secondary MVA technology has too high a detection limit, it could compromise the effectiveness of CCS, provide misleading inventory of CO_2 in storage and not provide the needed assurances for protection of the environment. The secondary technologies for CO_2 monitoring are shown in Table 5-1 and elaborated upon in the appendices.

5.3 Role of Potential Additional MVA Technologies

Through Federal and private sector funding, promising additional technologies are being developed to better understand the long-term behavior of CO_2 in the broad portfolio of potential GS sites (e.g., oil and gas reservoirs, deep coal beds, saline aquifers). In addition, new technologies can be improved and modified for detailed monitoring of CO_2 in GS. These potential additional technologies may currently be cost or time prohibitive and lack required precision. Potential additional monitoring techniques may have significant advantages over existing MVA technologies by improving the assessment and confirmation of the migration of CO_2 (free and dissolved) in the storage formation, long-term storage integrity, volume and rate of potential leakage in the overlying and underlying formations, and detection of potential leakage pathways from the storage formation to the atmosphere. Several of the Secondary and Potential Additional Technologies can be used in non-invasive applications to assess plume location and areas of potential leakage over larger spatial scales compared to Primary Technologies. Techniques like seismic reflection, ground swell, and vegetative stress monitoring can provide a strong indication of the extent of the CO_2 plume and pressure front (and any indication of leakage) over a relatively large area compared to the Primary Technologies, which require investigation through invasive techniques (well drilling, sample coring, etc.) and are constrained to fixed, spatially–limited locations. The potential additional technologies are shown in Table 5-1 and elaborated upon in the Appendices II and III.

It is believed that by 2012 modifications and improvements to monitoring protocols through the development of secondary and potential additional technologies will reduce GS cost and enable 99 percent of injected CO_2 to be credited as net emissions reduction. The use of one or more primary technologies can address the retention requirements for each of the MVA goals for GS outlined in Section 1.3 (Table 5-1). Achieving these MVA technology goals will provide the confidence that specified retention rates are achieved for injected CO_2 stored underground at a GS project (on a mass balance basis). Ultimately, a robust MVA program will likely be critical in establishing CCS as a viable GHG mitigation strategy.

5.4 Application of Monitoring Techniques and Regulatory Compliance

While a broad range of safety and environmental issues must be addressed to ensure safe and effective storage, the majority of the issues hinge on two primary factors:

- The extent, location, and nature of possible CO_2 leakage out of the primary storage horizon and potential leakage from the subsurface back into the atmosphere.
- Implementation of effective controls on injection well completion, injection rates, and wellhead and formation pressures.

To address the first of these issues from a monitoring perspective, it is necessary to be able to monitor the plume location of a separate CO_2 phase, either as a supercritical fluid or gas, in the subsurface. If there were evidence that significant leakage had occurred from the primary storage structure and CO_2 had migrated to the land surface, methods for monitoring the concentration and flux of CO_2 at the land surface would be highly desirable.

Meeting the second need, ensuring effective injection well control, will require monitoring the condition of the injection well, injection rates, wellhead pressures, and the formation pressure (Benson and Myer, 2002). A number of specific monitoring objectives, recommended to achieve monitoring goals, have been identified by Benson et al. (2004), including:

- Establishing baseline conditions from which the impacts of CO_2 storage can be assessed.
- Assessing the integrity of shut-in, plugged, or abandoned wells.
- Monitoring to ensure injection effectiveness.
- Monitoring to detect the location of the injected CO_2 plume.
- Comparing model predictions to monitoring data.
- Detect and quantify leakage from the storage formation to other strata or the surface.
- Assess health, safety, and environmental impacts of leakage.
- Monitoring to detect micro-seismicity associated with CO_2 injection.
- Monitoring to aid in the design and evaluation of remediation efforts, if needed.
- Evaluating interactions with, or impacts on, other geological resources.
- Reassuring the public, where visibility and transparency are of prime importance.

Table 5-1: List of RCSPs' Monitoring Tools for Phase II and Phase III Projects

Objectives	Primary Technologies	Secondary Technologies	Potential Additional Technologies
Atmospheric Monitoring ***Objectives:*** • Ambient CO_2 Concentration • CO_2 surface flux		CO_2 Detectors *(Ambient CO_2 Concentration)* Laser systems and LIDAR* *(Ambient CO_2 Concentration)*	Eddy Covariance *(Surface Flux)* Advanced Leak Detection System *(Surface Flux)* Isotopes
Near-Surface Monitoring ***Objectives:*** • Groundwater Monitoring • Fluid Chemistry • Soil gas monitoring • Crustal Deformation • Leak Detection • Vegetative Stress Monitoring • Vadose Zone Characterization	Geochemical Analysis *(Groundwater Monitoring)* *(Fluid Chemistry)*	Advanced Water Quality Analysis • Inorganics & Organics • Isotopes • Total Organic and Inorganic Carbon Aerial Photography *(Vegetative Stress)* *(Crustal Deformation)* Seismic Surveying *(Vadose zone characterization)* *(Leak Detection)* • Shallow 2-D Seismic Soil and Vadose Zone Gas Monitoring *(Gas sampling)* Flux Accumulation Chamber *(Surface Flux)*	Tracers *(Leak Detection)* • Noble Gases • Mercaptans • Stable Isotopes • Perfluorocarbons Geophysics *(Leak Detection)* *(Vadose zone characterization)* • Conductivity • Induced Polarization • Self-Potential Tiltmeters *(Crustal Deformation)* Remote Sensing *(Crustal Deformation)* • Color Infrared Transparency Film • Hyper-spectral – multispectral • Synthetic Aperture Radar & InSar
Subsurface Monitoring ***Objectives:*** • Groundwater Monitoring • Soil Gas Monitoring • Leak Detection • Subsurface and Reservoir Characterization • Plume Tracking • Well Integrity Testing	Water Quality Analysis • Injection Fluid Monitoring • Formation Fluid Monitoring • Water Level Caprock Integrity *(Subsurface and Reservoir Characterization)* • Geomechanical Analysis • Core Collection Wireline Logging *(Well Integrity)* • Temperature • Noise • Cement Bond • Density • Gamma Ray • Sonic *(Acoustic)* Physical Testing *(Well Integrity)* • Annulus Pressure • Injection Volume/Rate • Wellhead Pressure • Downhole Pressure • Downhole Temperature	Seismic Surveying *(Reservoir Integrity)* • Acoustic (2-D and 3-D) • VSP • 2-D and 3-D Geochemistry *(Reservoir Integrity)* • Brine/Fluid Composition • Tracer Injection/Monitoring Injection Well Logging *(Wireline Logging)* *(Plume Tracking)* *(Reservoir Integrity)* • Temperature Logging • Reservoir Saturation Tool • Optical	Geophysical Techniques *(Leak Detection)* *(Subsurface and Reservoir Characterization)* *(Plume Tracking)* • Crosswell Seismic • Microseismic *(Passive)* • EMIT • Magnetotelluric Sounding • Resistivity and EM • Electrical Resistivity Tomography • Time-lapse Gravity Survey • Electromagnetic Resistivity • Wireline Logging *(Well integrity and Subsurface Characterization)* - Resistivity

The concept of four distinct phases in the life cycle of a GS project was introduced by Benson et al. (2004). Monitoring activities will vary among these phases, which are defined as follows:

1. **Pre-operation Phase:** Project design is carried out, baseline conditions are established, geology is characterized, and risks are identified.
2. **Operation Phase:** Period of time during which CO_2 is injected into the storage reservoir.
3. **Closure Phase:** Period after injection has stopped, during which wells are abandoned and plugged, equipment and facilities are removed, and the agreed upon site restoration is accomplished. Only necessary monitoring equipment is retained.
4. **Post-closure Phase:** Period during which ongoing monitoring is used to demonstrate that the storage project is performing as expected and that it is safe to discontinue further monitoring. This phase will last for decades. Once it is satisfactorily demonstrated that the site is stable, monitoring will no longer be required except in the event of leakage, legal disputes, or other matters that may require new information about the status of the storage project.

Each monitoring phase (pre-operational, operational, closure, and post-closure) of a GS project will employ specialized monitoring tools and techniques that will address specific atmospheric, near-surface, and subsurface monitoring needs. Atmospheric monitoring techniques are critical in identifying CO_2 concentrations above ambient background levels. Near-surface techniques play a vital role in the preservation of shallow groundwater sources and supply critical information on any major vertical migration of injected CO_2. Subsurface monitoring techniques can identify CO_2 plume location, pressure propagation, and reservoir and seal integrity. Monitoring packages for a particular GS project will depend heavily on site-specific geologic conditions and project objectives.

The recommended steps for selection of suitable geophysical techniques include:

- Developing geologic models for the sequestration site that includes the reservoir, the seals, and overlying geology, aquifer(s), vadose zone, and surface.
- Performing reservoir simulations of the sequestration processes of interest, such as prediction of changes and the distribution of fluid phases resulting from CO_2 injection.
- Using the geologic model and results of reservoir simulations to perform numerical simulations to predict the response of candidate geophysical and geochemical monitoring techniques.

In addition to site selection, determining the appropriate monitoring technique is a key factor for successful GS of CO_2. Monitoring techniques can provide information to address safety and environmental concerns, address research questions, and provide verification for national accounting of GHG emissions and support GHG registries. Based on risk assessment, evaluation of the project goals, and mandatory monitoring requirements, a decision tree for selection of monitoring techniques for a particular research or operational GS project can be constructed (Figure 5-1 for pre-operation and operation phases; Figure 5-2 for post-injection monitoring).

The results of monitoring throughout the life cycle of GS project from pre-operation to post-closure phases will provide information to operators and regulators. This information will provide the flexibility to revise operational and monitoring activities that may persist for many decades. The goal is to limit unnecessary burden on owners, operators, or permitting agencies and provide a strong foundation for national consistency in permitting and safe operation of GS projects.

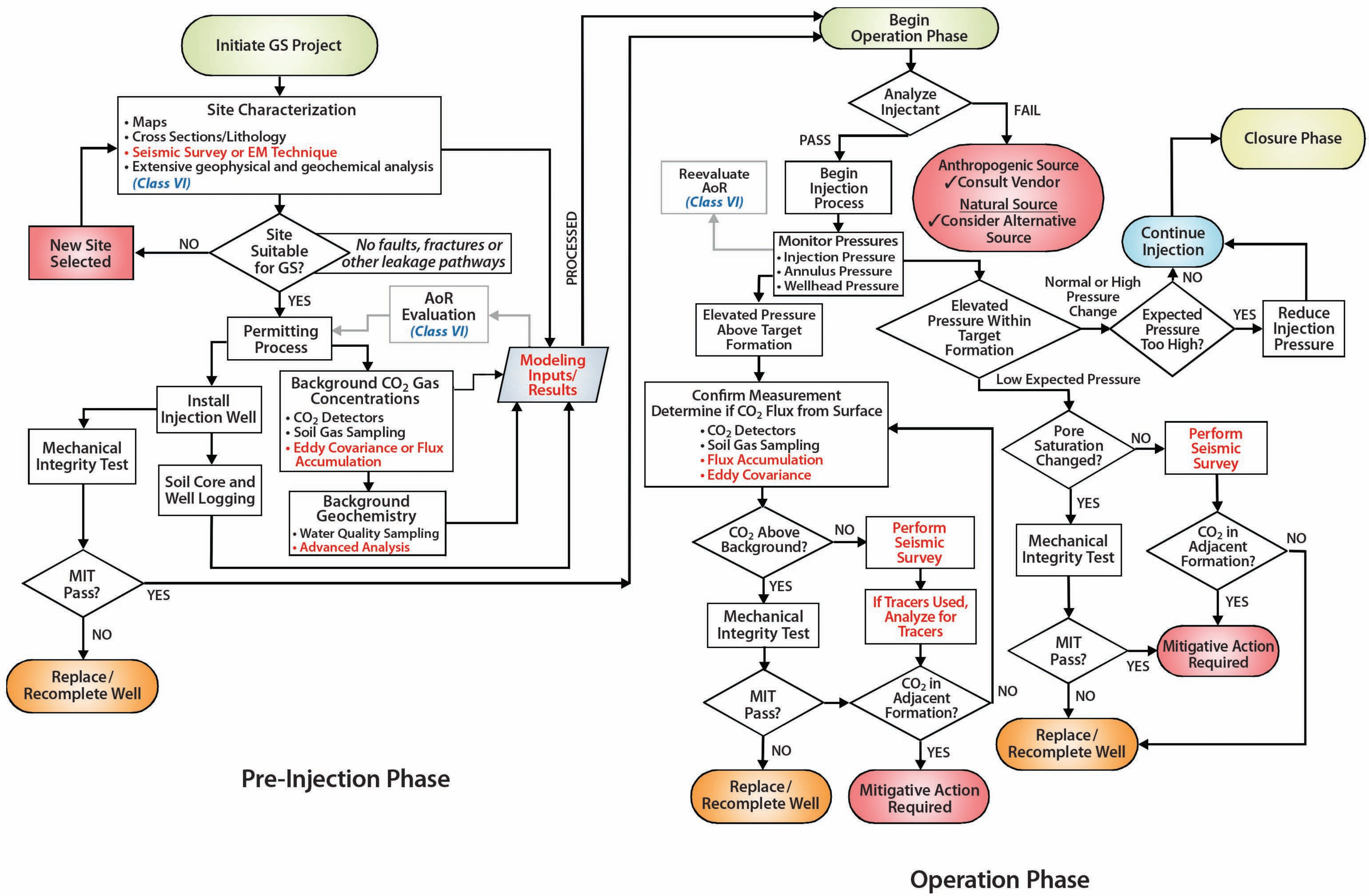

Figure 5-1: Decision tree for pre-operational and operational phase monitoring techniques for GS project based on mandatory monitoring requirements and proposed Class VI requirements. Primary technologies are listed with black text and solid figure lines, whereas Secondary and Potential Additional Technologies are listed with red text and dashed figure lines. Light-grey lines depict proposed UIC regulatory changes for Class VI wells.

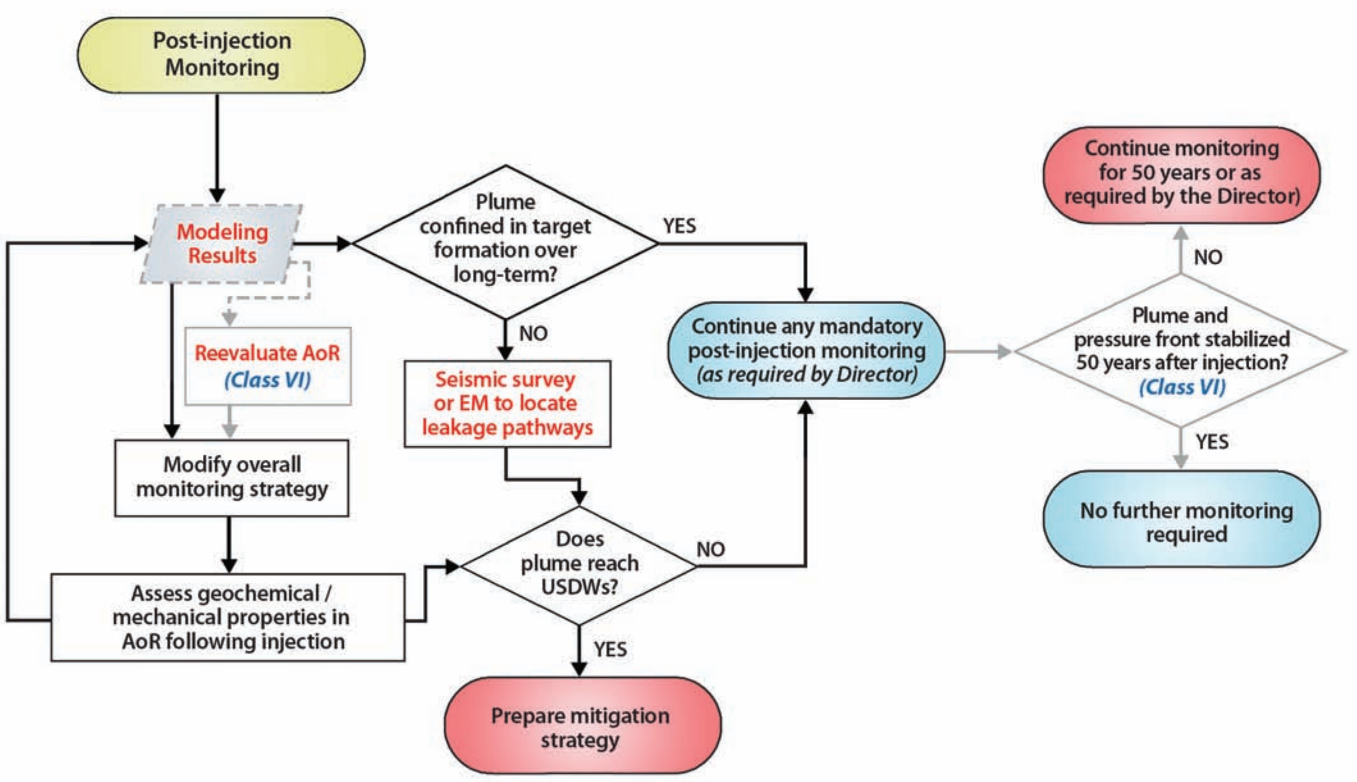

Figure 5-2: Decision tree for post-injection monitoring techniques for a GS project based on mandatory monitoring requirements. Primary technologies are listed with black text and solid figure lines, whereas Secondary and Potential Additional Technologies are listed with red text and dashed figure lines. Light-grey lines depict proposed UIC regulatory changes for Class VI wells.

5.5 Pre-Operation Phase

Site characterization and selection is the first step in a monitoring program that can assure the safety and integrity of a GS project. Most elements of site characterization are considered to be normal operational practice, based on existing regulations for natural gas storage, injection of water for secondary oil recovery, and disposal of produced water, acid-gases, and hazardous wastes. Site characterization to establish a baseline can include:

- Determination of baseline characteristics of the target formation.
- Bounding formation information, including continuity and thickness of caprock, lithology, integrity, presence of fracturing, and how containment can be assured.
- Well completion and casing data, well logs, and well testing requirements, such as those developed for Alberta (EUB, 1994) and the UIC Program administered by either EPA or the designated state agency under the 1974 SDWA (EPA, 2008a).
- Information (well location, status, and completion and casing data) on all wells in the vicinity of the project, including any wells that have been shut down, had workovers or remedial actions.
- Emergency response plans and mitigation actions (Monea et al., in press).

At the close of site characterization, the GS site and proposed monitoring plan must be permitted by the appropriate regulatory agency prior to operations. The RCSPs' GS field projects have developed not only monitoring technologies, but have also contributed to the development of monitoring requirements for CCS. The RCSPs' demonstration projects have initiated a high-level of activity by Federal (EPA, BLM), state, and other organizations (Navajo EPA and IOGCC). Activity to develop monitoring requirements for CCS is still underway and has contributed to the proposed Federal EPA rules establishing a new UIC class for injection wells associated with GS projects (Federal Register, July 25, 2008). The Phase II projects have helped initiate the necessary regulatory activity to develop monitoring requirements to validate and potentially deploy large-scale geologic CCS.

5.5.1 Pre-operation Monitoring

Monitoring during the pre-operation phase of a GS project is used to establish baseline conditions, including characterization of geologic features within the vicinity of the site, and identifying potential risks and leakage pathways (LBNL, 2004). Pre-operation monitoring involves all activities prior to injection, including: site screening and selection, baseline characterization, well-drilling and installation, well-integrity testing, and caprock and formation integrity testing. The suite of monitoring tools and techniques implemented during this project phase should be capable of determining wellhead and formation pressure; establishing baseline soil gas, groundwater, and atmospheric CO_2 concentrations; verifying injection rate (and production rate if it is an EOR or gas extraction project); and assessing site geology. A summary of the purpose for each phase of monitoring for a GS project can be found in Appendix IV.

Monitoring packages for a particular storage project will heavily depend on site-specific objectives and characteristics. In addition, specific monitoring tools and their application, including the spatial and temporal scales in which they are used, will vary across project phases (pre-operation, operation, closure, and post-closure) and may vary due to specific project events (i.e., change in direction in CO_2 plume migration, discovery of a leakage pathway, shift in target formation integrity, etc.). Pre-operation monitoring tools and applications are described below according to their function.

Geophysical Approaches – Geophysical monitoring in the pre-operation phase of a GS project is used to assess the baseline geological conditions in and around the site vicinity prior to CO_2 injection. Integration of the geophysical approaches is needed to get the best quantitative estimate of CO_2 in place. Available geophysical monitoring techniques include seismic surveys, EM imaging, well logging, sample core collection and analysis, and pressure and temperature monitoring. Results of baseline geophysical testing can be compared to subsequent monitoring during the injection and post-closure phases to observe time-lapse changes resulting from the injection process. Requirements under UIC regulations for Class I (non-hazardous) and II wells indicate that injection pressures must be monitored so as to not cause fracturing into the confining zone or cause fluid movement into USDWs. Additional requirements demand monitoring and reporting of the CO_2 injection flow rate and volume, injection and annulus pressure, as well as periodic well MIT (EPA, 2008a). Step-rate tests conducted prior to injection can indicate the maximum allowable injection pressure without inducing failure or formation parting pressures (usually, injection pressure will be some fraction of estimated formation pressure, with maximum injection pressure capped by regulation). Downhole pressure sensors can be used to obtain pressure readings inside the well casing. Step-rate tests only need to be conducted once for each project injection well drilled during the pre-operation period. Refer to the EPA step-rate testing procedure for additional details on conducting a step-rate well test (http://www.epa.gov/region8/water/uic/INFO-StepRateTest.pdf).

CO_2 injection flow rate and volume can be easily monitored at the wellhead. Flow rate and volume readings will obviously be zero during the pre-operation phase. Pressure sensors placed in the wellhead and annulus can provide instantaneous, real-time pressure readings for all project operational phases. Although not a primary practice at GS sites, downhole pressure (P) and temperature (T) sensors can be used to detect baseline conditions (P and T) in the target formation prior to injection. These readings can be helpful in assessing overall caprock and target formation integrity once the injection phase begins, as P and T readings will definitely change from baseline conditions.

An MIT is needed to satisfy requirements set forth in 40 CFR § 146.8(b) for Class I and II wells to ensure the absence of significant leaks in the tubing, packer, or casing and to ensure that no significant fluid movement into a USDW through vertical channels adjacent to the injection wellbore will occur. No specific MIT is required for Class V wells; however, permit conditions will likely require operators to demonstrate internal and external integrity during the lifetime of the project, and this may require more frequent testing. One of the three following methods is considered a suitable MIT according to 40 CFR § 146.8(b): (1) conduct an initial pressure test and monitor the tubing-casing annulus pressure with sufficient frequency to be representative while maintaining an annulus pressure different from atmospheric pressure measured at the surface; (2) pressure test with liquid or gas; or (3) record of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for certain existing Class II enhanced recovery wells. The MIT should be conducted once the well is complete and is required to be repeated at least once every five years or when packer reseating is conducted. Noise logs and cement bond logs (CBL) can be used to assess the integrity of the cement component of the well. Cement records are required for new and existing Class II injection wells in all EPA regions except Region 6 (Arkansas, Louisiana, New Mexico, Oklahoma, and Texas), where State or BLM records are used (unless a state has primacy over UIC regulations). CBLs are also required for new and existing Class II injection wells in all EPA regions except Region 5 (Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin). Surface casing cement is typically required to be circulated to the surface, while the production casing is typically cemented at least 100 feet above the injection zone. Refer to Table 4-2 for a complete summary of the monitoring, construction, and operation requirements for Class I, II, and V UIC injection wells. Appendices II and III provide detailed descriptions of monitoring tools available for GS projects to assess geophysical parameters.

Siting requirements for Class I and II UIC wells under CFR § 146.14 require demonstration of the presence and adequacy of injection and confining zones by presenting information on local geologic structures, faults, and other relevant geomechanical information. Maps and cross sections of site lithology, USDWs, and AoR are also required. For Class I and II injection wells, Federal UIC regulations require that the AoR be defined as either a fixed radius of one-fourth mile surrounding the well (or wells, for an area permit) or an area above the injected fluid and pressure front determined by a computational model. Class II well regulations also require a list of penetrations into the injection zone. Available monitoring tools for assessing subsurface geology include: core sampling, wireline logging (sonic, density, gamma ray, RST, and resistivity); EM techniques (electromagnetic induction tomography [EMIT] and magnetotelluric sounding); and seismic surveying (VSP, 2-D seismic, 3-D seismic, crosswell seismic, microseismic (passive) seismic, microseismic).

Core sampling is a relatively simple technique that can be used to assess the lithology at the sampling location as a function of depth. Sample cores can be taken as part of the well drilling process and at additional locations in and around the site. Sample cores only provide geologic information at their specific location. Site geology can be interpolated between coring locations and by the use of data gathered from other wells within the vicinity. Spatial placement and frequency of core samples will likely be based on the project operator's judgment and the available budget. Wireline logging is a common method for evaluating geologic formations by lowering an instrument and obtaining a profile of one or more physical properties along the length of the well. A variety of different well logs are available that can measure several different parameters – from the condition of the well to the composition of pore fluids and the mineralogy of the formation. Wireline logging can provide detailed information on rock and fluid characteristics in the immediate vicinity of the wellbore casing. Additional wells, either observation wells, monitoring wells, or production wells (for ECBM or EOR) would need to be placed in and around the site for any added geologic characterization.

EM and seismic survey methods are capable of providing a graphic depiction of the subsurface over a large area and are not limited to a specific sampling point (like sample cores and wireline logging). But they in exchange give up resolution, and quantitative properties. These techniques can provide detailed information of the subsurface (beyond UIC regulatory requirements) that can be used to in combination with well – based subsurface characterization methods (see Section 5.6). These available techniques can provide the necessary data needed to meet the siting requirements in 40 CFR § 146.14. The spatial scales at which the tools will be implemented will be based strictly on specific site characteristics, operator preference, and available budget.

Geochemical Methods – Geochemical monitoring approaches in the pre-operation phase of a GS project are used to assess the baseline groundwater quality and composition. Groundwater sources of interest include USDW around the injection site, as well as saline formation fluids (brine) and production well water from EOR and ECBM projects. Available geochemical monitoring techniques include basic groundwater quality monitoring, analysis for inorganics and isotopes, brine composition studies, and groundwater CO_2 tracer monitoring (all geochemical tools described in detail in Appendices II and III). Baseline groundwater samples can be collected to ensure data availability prior to first injection of CO_2. This will provide the basis against which further sampling and analytic work can be compared (Brown et al., 2001).

Requirements under UIC regulations under 40 § CFR 146.12 for Class I, II, and V wells indicate that no fluid movement is permitted to any USDWs and that the chemical composition of the injected fluid must be properly analyzed. Preventing fluid movement into USDWs is primarily based on high quality well construction rather than monitoring (refer to 40 CFR § 146.12 & 146.22 for respective Class I and Class II well construction requirements). Groundwater monitoring can be used to determine USDW integrity during and after the injection phase of the project.

The main geochemical technique used in the pre-operation project phase will be to conduct initial groundwater quality monitoring to identify USDWs in the vicinity of the project, establish back groundwater quality, as well as confirm that fluids in the target formation meet the criteria outlined in 40 § CFR 146.4, exempting them from USDW status. Additional permitting requirements include annual formation fluid analysis and quarterly analysis of the physical characteristics of the injected fluid (both require reporting to the permitting body following analysis).

Crustal Deformation – UIC standards do not mandate monitoring for surface deformation as a result of CO_2 injection under Class I (non-hazardous) and Class II wells. Two techniques that are commonly used to measure deformation, tiltmeters and synthetic aperture radar, are considered "promising technologies" and are discussed in Section 5.6.

Surface and Atmospheric Monitoring – Surface and atmospheric monitoring approaches in the pre-operation phase of a GS project are used to assess the baseline ambient CO_2 and soil gas CO_2 concentrations within the vicinity of the injection site. Natural and anthropogenic non-point sources of CO_2 in the vicinity of the site need to be addressed in order to prevent false-positive CO_2 readings once injection has commenced. Available near-surface and atmospheric monitoring techniques include atmospheric CO_2 detectors, flux ACs, Advanced Leak Detection Systems, EC, and soil and vadose zone gas sampling. (All near-surface and atmospheric tools are described in detail in Appendices I and II.) Baseline atmospheric and soil gas CO_2 concentrations provide the basis against which further sampling and analytic work can be compared in the operations and post-injection project phases (Brown et al., 2001). Requirements under UIC regulations for Class I, II, and V wells do not indicate continuous or periodic atmospheric or soil gas monitoring for CO_2 concentrations for any project phase. However, UIC permits normally require immediate reporting of CO_2 releases into the atmosphere. Pre-operation CO_2 releases could result from a wellhead breach or damage to the CO_2 transporting system (pipeline, truck, tanker, etc.). CO_2 detectors should continuously operate in the vicinity of site workers to establish baseline CO_2 concentrations prior to injection and to detect and warn site personnel of elevated and unsafe levels of CO_2. Flux accumulation chambers, Advanced Leak Detection Systems, and eddy covariance techniques can be used to detect CO_2 fluxes from the soil surface. These techniques are typically used only in research applications and are discussed in Sections 5.5 and 5.6.

5.6 Operation Phase

As a GS project is permitted and approaches operational status, three types of monitoring (operational monitoring, verification monitoring, and environmental monitoring) are initiated. These monitoring levels represent an increasing progression of monitoring intensity, duration, and technology application, as briefly described below.

Operational Monitoring – Minimum requirements (specified by regulations) for baseline/operational monitoring can closely resemble those of a CO_2 EOR flood and provide a basis for verification. Additional operations monitoring is guided by the ongoing complexities of injection and production. Monitoring of injection volume, wellhead and downhole pressure, and the injection zone is expected during operations, which has been the case at Weyburn, In Salah, Sleipner, and the RCSPs' Phase II and Phase III demonstration projects. Some of these parameters (e.g., produced oil volume) are not relevant for saline formation storage projects. Key components of operational monitoring used in CO_2 EOR (Jarrell et al., 2002) and applicable to CCS include:

- **Injection Metering and Pressure Monitoring:** All injection wells should have meters and pressure sensors to accurately measure injection and production rates, surface casing pressure, bottom-hole injection pressure, and annulus pressure to verify that no casing, tubing, or packer leaks exist.
- **Injection Profiles:** This logging reveals where the injectant is flowing; such measurements are not continuous, but may be required early in the injection and on an occasional basis afterwards (e.g., once a year).
- **Reservoir Pressure Data:** This data may be acquired either with downhole pressure sensors or by inverting surface pressure and injection data, given knowledge of the injection profile.
- **Step-rate Tests:** These tests are performed before injection to reveal the maximum allowable pressure without inducing failure or exceeding formation parting pressures. Usually, injection pressure will be some fraction of estimated formation pressure, with the maximum injection pressure cap set by regulation.

Verification Monitoring – This refers to additional measurements that improve the understanding of complex processes occurring in situ. This level of monitoring is specified by regulatory agencies and independent verification bodies and involves tracking and quantifying the volume of injected CO_2.

Environmental Monitoring – This refers to monitoring aimed at safeguarding against risks to health, safety, and the environment. Depending on the risk level of the project, aspects of environmental monitoring may be part of operational monitoring.

Monitoring requirements for the operation phase are discussed in more detail in the next section.

5.6.1 Operation Monitoring

Monitoring during the operation phase of a GS project is used to ensure safety with all procedures associated with fluid injection. Operational monitoring involves all fluid injection activities, including: site screening and selection, baseline characterization, well drilling and instillation, well integrity testing, and caprock and formation integrity testing. The suite of monitoring tools and techniques implemented during this project phase should be capable, at a minimum, of determining wellhead and annulus pressure; measuring soil gas, groundwater, and atmospheric CO_2 concentrations; continuously monitoring injection rate (and production rate, if it is an EOR or gas extraction project); and tracking cumulative injected volumes. A summary of the purpose for each phase of monitoring for a GS project is located in Appendix IV.

Minimum requirements (specified by regulations) for baseline/operational monitoring closely resemble those of a CO_2 EOR flood and provide a basis for CO_2 accounting. Supplemental operations monitoring is influenced by site-specific complexities of injection and production. Monitoring of injection volume and flowrate, wellhead and annulus pressure, and the well integrity is expected during operations. This has been the case at Weyburn, In Salah, and Sleipner, and is being applied widely across the RCSPs'

Phase II and Phase III demonstration projects. Some parameters (e.g., produced oil volume) are not relevant for saline formation storage projects. Key components specific to CO_2 EOR operational monitoring that are applicable to CCS include injection metering and pressure monitoring, injection profiles, and reservoir pressure data (Jarrell et al., 2002) (as described in 5.6).

Monitoring tools used for a particular storage project to satisfy mandatory monitoring requirements will heavily depend on site-specific objectives and characteristics. In addition, specific monitoring tools and their application, including the spatial and temporal scales in which they are used, will vary across project phases (pre-operation, operation, closure, and post-closure) and may vary due to specific project events (e.g., change in direction in CO_2 plume migration, discovery of a leakage pathway, shift in target formation integrity, etc.). Operational monitoring tools and applications are described below according to their function.

Geophysical Approaches – Available geophysical monitoring techniques practical for both pre-operation and operation phase include seismic surveys, EM imaging, well logging, sample core collection and analysis, and pressure and temperature monitoring. Results of baseline geophysical testing can be compared to operational monitoring data obtained during injection to observe time-lapse differences between baseline conditions and conditions after injection. UIC regulations for Class I and II wells require monitoring and reporting of the CO_2 injection flow rate and volume, injection and annulus pressure, as well as periodic well MIT (EPA, 2008a). While complete Class V well operational monitoring requirements are usually project specific, complete Class I requirements differ significantly from Class II requirements (mostly due to the production expected from Class II wells).

As mentioned in Section 5.6, CO_2 injection flow rate and volume can be easily monitored at the wellhead using a flow meter that reads instantaneous and cumulative flows. Flow rate and volume readings are required to be continuously monitored throughout the injection period. Pressure sensors placed in the wellhead and annulus can provide instantaneous, real-time pressure readings for all project operational phases. Specific Class I operational geophysical monitoring requirements, as outlined by 40 CFR § 146.13, include at a minimum:

- Analysis of the injected fluids with sufficient frequency to yield representative data on their characteristics (quarterly).
- Installation and use of continuous recording devices to monitor injection pressure, flow rate and volume, and the pressure on the annulus between the tubing and the long string of casing (continuous).
- Demonstration of mechanical integrity pursuant to § 146.8 at least once every five years during the lifetime of the well.
- The type, number, and location of wells within the AoR to be used to monitor any migration of fluids into, and pressure in, the USDW, the parameters to be measured, and the frequency of monitoring.

Specific Class II operational monitoring requirements as outlined by 40 CFR § 146.23 include at a minimum:

- Monitoring injected fluids at sufficiently frequent time intervals to yield data representative of their characteristics.
- Observation of injection pressure, flow rate, and cumulative volume at least with the following frequencies:
  - Weekly for produced fluid disposal operations.
  - Monthly for enhanced recovery operations.
  - Daily during the injection of liquid hydrocarbons and injection for withdrawal of stored hydrocarbons.
  - Daily during the injection phase of cyclic steam operations and recording of one observation of injection pressure, flow rate, and cumulative volume at reasonable intervals no greater than 30 days.

- A demonstration of mechanical integrity pursuant to § 146.8 at least once every five years during the life of the injection well.

- Maintenance of the results of all monitoring until the next permit review (see 40 CFR 144.52(a)(5)).

- Hydrocarbon storage and enhanced recovery may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well operating with a common manifold. Separate monitoring systems for each well are not required, provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.

40 CFR § 146.13 also requires the development of an Ambient Monitoring Plan by the well operator that, at a minimum, annually monitors the pressure buildup in the injection zone (obtained by downhole pressure monitoring devices), including the shutdown of the well to conduct an observation of the pressure fall-off curve. Additional geophysical monitoring tasks may be prescribed by the Director (Regional Administrator, State director, or Tribal director) to any Ambient Monitoring Plan, including:

- Continuous monitoring for pressure changes in the first aquifer overlying the confining zone. Quarterly sampling of aquifer constituents (specified by the Director) may also be required.

Class V well operation monitoring requirements may be similar to many of the Class I well requirements listed above. Additional Class V monitoring may be required compared to Class I; however, permit conditions, dictated by site-specific situations and scenarios, are likely to vary across different projects.

The MIT procedure will not change from the initial test in the pre-operation phase to the periodic testing schedule required for operation phase monitoring. UIC requirements for Class I and Class II wells require an MIT at least once every five years during the lifetime of the injection well or when packer reseating is conducted. Figure 5-3 shows the CO_2 pathways around an injection well that may be tested by the MIT. Refer to Table 4-2 for a complete summary of the monitoring, construction, and operation requirements for Class I, II, and V UIC injection wells. Appendices II and III provide detailed descriptions of monitoring tools available for GS projects to assess geophysical parameters.

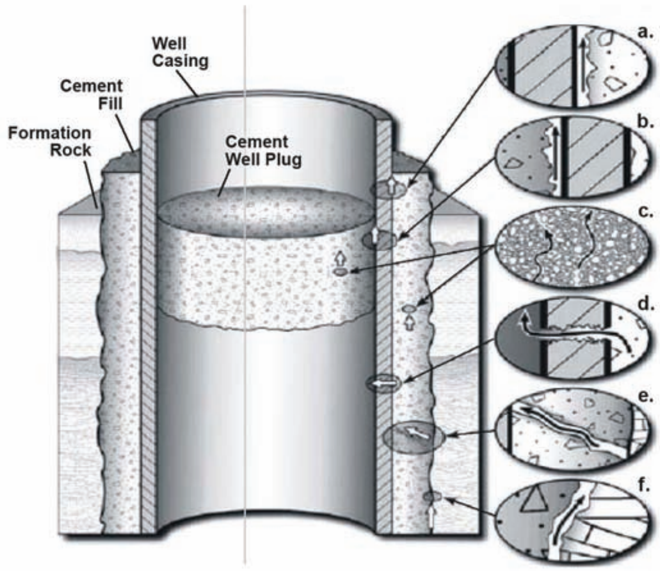

Figure 5-3: Potential leakage pathways along an existing well: between cement and casing (Paths a and b), through the cement (c), through the casing (d), through fractures (e), and between cement and formation (f) (Celia et al., 2004).

Geochemical Approaches – Geochemical monitoring approaches in the operation phase of a GS project are used to detect any changes in groundwater and formation fluid quality and composition from baseline conditions. Monitoring requirements under UIC regulations specific to geochemical applications include monitoring the physical characteristics of the injected fluid (sampled and analyzed quarterly) for Class I and Class II wells. Additional requirements particular to site-specific Class I Ambient Monitoring Program include:

- The use of indirect geophysical techniques to determine the position of the waste front, the water quality in a formation designated by the Director, or provide other site specific data.

- Periodic monitoring of the groundwater quality in the lowermost USDW.

- Any additional monitoring necessary to determine whether fluids are moving into or between USDWs.

Class V well permits may require analysis of formation fluid or groundwater (annually or monthly, if performed) in addition to monitoring the injected fluid (as indicated by UIC Class V permit monitoring requirements for Core Energy, LLC in Otsego County, Michigan (EPA, 2007)).

Crustal Deformation – UIC standards do not mandate operational monitoring for surface deformation as a result of CO_2 injection under Class I (non-hazardous) and Class II wells.

Surface and Atmospheric Monitoring – Surface and atmospheric monitoring approaches in the operations phase of a GS project are used to assess ambient CO_2 and soil gas CO_2 concentrations in the vicinity of the injection site. (All near-surface and atmospheric tools described in detail in Appendices I and II.) Requirements under UIC regulations for Class I and II wells do not indicate continuous or periodic atmospheric or soil gas monitoring for CO_2 concentrations for any project phase. UIC permits do require immediate reporting of CO_2 releases into the atmosphere. Operation phase CO_2 releases could result from a breach from the wellhead, damage to the system transporting CO_2 to the site (pipeline, truck, tanker, etc.), leakage around the well casing (at the injection well, monitoring wells, or abandoned wells within the AoR), or from movement from the target formation (via caprock fracturing, faults, or other leakage pathways). CO_2 detectors should continuously operate in the vicinity of site workers and warn site personnel of elevated CO_2 concentrations during site operation. Flux accumulation chambers, Advanced Leak Detection Systems, and eddy covariance techniques can be used to detect CO_2 fluxes from the soil surface; however, they are typically used primarily in research applications and are discussed further in Appendix I and II.

5.7 Closure Phase

Well and site closure are important for protecting against leakage to the atmosphere and USDWs. GS well operators will need to maintain recordkeeping and reporting information and plugging and abandonment reports during the operations phase of the project, as well as for a significant period after site closure. The time extent of this recordkeeping is not defined under present rules. Prior to closure and the plugging of a well, operators will need to notify the appropriate regulatory authority and close the well(s) in accordance with the approved post-injection site care plan or specify the differences between the plan and the actual closure.

Operators will need to plug wells in a manner specified by the regulatory authority. This may be accomplished in a number of ways using a variety of different materials. The materials must be compatible with the fluids that they may come into contact with and must prevent the movement of fluids outside the storage horizon. Specialized cements, resistant to CO_2 for long periods of time, may be required. To ensure that wells at a closed site are in a state of static equilibrium, tagging the cement, integrity testing, and other mechanical techniques may be required to test the adequacy of cement plugs. All records and the post-closure monitoring plan will need to be submitted to the appropriate regulatory agency. Important steps in injection well plugging as outlined by 40 CFR 144.12 include:

- Well shall be plugged with cement in a manner which will not allow the movement of fluids either into or between USDWs.
- The well to be abandoned shall be in a state of static equilibrium with the mud weight equalized top to bottom.
- Prior to abandoning a Class V well, the owner or operator shall close the well in a manner that prevents the movement of fluid containing any contaminant into a USDW.
- Materials must be compatible with the fluids with all subsurface fluids and must prevent the movement of fluids outside the storage horizon.
- Tagging the cement, integrity testing, and other mechanical techniques may be required to test the adequacy of cement plugs.

For the proposed Class VI well, EPA is proposing to provide owners or operators flexibility in meeting the well plugging requirements by allowing the owner or operator to choose from available materials and tests to carry out the proposed requirements. EPA is not specifying the types of materials or tests that must be used during well plugging because a variety of appropriate methods exists and new materials and tests may become available in the future.

Injection well plugging must comply with requirements of 40 CFR 144.12(a). Additional post-closure monitoring is also required (as mentioned in Section 4.3), which is an additional requirement to current UIC regulations. The Class VI proposal would require that owners or operators develop a post-injection site care and closure plan and monitor the site following cessation of the injection activity. Post-closure care includes recording certain formation pressures and determining location of the plume front. EPA is tentatively proposing a post-injection site care (monitoring) period of 50 years, with the Director retaining discretion as to whether the 50-year period should be lengthened or shortened. Additional requirements demand that owners or operators demonstrate and maintain financial responsibility for corrective action described in 40 CFR 146.84, and have the resources for activities related to closing and remediating GS sites. Financial assurance is typically demonstrated through two broad categories of financial instruments: 1) third party instruments, including surety bond, financial guarantee bond or performance bond, letters of credit (the above third party instruments must also establish a trust fund), and an irrevocable trust fund and 2) self-insurance instruments, including the corporate financial test and the corporate guarantee (*Federal Registe*r, July 25, 2008).

5.8 Post-Closure Phase

During the post-closure phase, operators would periodically report on the results of monitoring. Monitoring would focus on: 1) recording the pressure differential between pre-operation and anticipated post-injection pressures in the injection zone; 2) predicted position of the plume and associated pressure front at the time the site is closed; 3) description of post injection monitoring location(s), methods, and proposed frequency of monitoring; and 4) assuring that vertical leakage to the surface through wellbores and other pathways is minimal. Monitoring tools, such as 3-D seismic and instrumented monitoring wells, could be used to track the position of the CO_2 plume and pressure front and to identify any potential vertical leakage toward the surface. A record of the pressures in the injection formation and surrounding areas, as well and the pressure decay rate, can confirm that the injected CO_2 is not moving beyond the specified GS horizon.

The presence of physical and geochemical trapping mechanisms is likely to reduce the mobility of CO_2 over time and research also suggests that pressure within the storage system will drop significantly when injection ceases, thus decreasing the risks of induced seismic activity, faulting, and fracturing (Birkholzer et al., 2005), making storage more secure over longer timeframes. However, the timeframe over which this happens and the frequency and duration of post-closure monitoring are difficult to define, because it is based on site-specific geologic considerations. Although site dependent, UIC Classes I II and V typically use 30 years as the duration for post-closure monitoring. The UIC Class VI proposed regulations require 50 years of post-closure monitoring of future CO_2 injection wells. If it can be determined that no plume migration outside of the target formation occurs within these post-closure monitoring periods (normally by matching favorable monitoring and modeling results), then no further monitoring is needed as the plume is considered to be contained within its' target formation.

5.9 Application of MVA Technologies at GS Field Projects

DOE has supported the application of MVA technologies at several field sites through both the Core R&D and the RCSPs. The following summarizes some of the key point on how primary and secondary technologies have been used to satisfy regulatory permitting requirements under the UIC program.

Weyburn is an example of a project using MVA techniques to track the behavior of injected CO_2. In 2000, IEA launched a comprehensive geological study of the Weyburn CO_2 storage site. Production fluid sampling and geochemical analyses (Shevalier et al., 2004; Quattrocchi et al., 2004) were conducted at Weyburn at regular intervals of three to four months over a three-year period, with the primary objective of tracing the distribution of CO_2 over time within the reservoir. The chemical analysis allowed the short-term chemical interactions of the CO_2 with the reservoir fluids and rock matrix to be monitored. The primary advantage of geochemical monitoring is that it is capable of providing detailed and sensitive measurements of CO_2 concentrations in sampled subsurface fluids at a relatively low cost. The primary disadvantage of this technique is that the spatial sampling is typically sparse, as it is limited by the distribution of boreholes where fluids can be sampled. In the case of non-EOR CO_2 storage, the number of wells available for sampling is likely to be limited. IEA concluded that the geology of Weyburn field is suitable for long-term CCS, that the primary reservoir seals are competent, forming thick and extensive barriers to upward fluid migration, and that faults and fractures in the region show no fluid conductance. Risk-assessment modeling suggests that approximately 0.02 percent of the initial CO_2 in place after EOR operations are complete will migrate above the reservoir after 5,000 years; of this small percentage of CO_2, most will diffuse into the overlying caprock, and none will reach near-surface strata containing potable aquifers. Moreover, the cumulative leakage through existing wells in the field is expected to be less than 0.001 percent of the initial CO_2 in place (Zhou et al., 2004).

For accurate CO_2 volume estimation, seismic data require calibration (e.g., time-lapse downhole seismic logging, pressure monitoring, sample coring) and integration with detailed reservoir flow simulations as a complementary constraint. Reservoir simulation models require site-specific geologic parameters to properly simulate plume fate and transport over time. Primary technologies (Tables 5-1 and 6-1) needed to satisfy UIC mandatory monitoring requirements can provide the necessary site-specific physical (lithology, pressures, temperatures) and chemical (groundwater and formation fluid compositions, soil gas composition) data needed to generate in-depth reservoir simulation models. However, the application of primary technologies is spatially limited and normally only generates data at or in the vicinity (as in many wireline logging applications) of a specific monitoring location.

At the Frio Brine pilot, a detailed characterization was conducted using primary reservoir assessment technologies. This effort included use of log analysis and seismic surveys to define facies, structure, and diagenetic evolution and estimation of petrophysical and geochemical properties using core from analogous facies in Chambers County to build a quantitative reservoir model. Wireline logging, pressure and temperature measurement, and geochemical sampling were also conducted during injection (Hovorka, et al, 2006). A wireline sonic log taken three months after injection showed a weak and slower arrival of compressional wave over the perforated injection interval when compared to the baseline sonic log. The successful measurement of plume evolution is an effective method to monitor CO_2 in reservoirs and document migration (Sakurai, et al, 2005).

Seismic monitoring can be useful for detecting significant leakage or migration of CO_2 from the reservoir. Estimates from the Weyburn project suggest that CO_2 leakage in the order of 2,500 to 10,000 tonnes (a mere 0.0.008 to 0.03 percent of the total anticipated injection amount of approximately 30 million tonnes) would be detectable, assuming that the CO_2 remains concentrated within the overlying strata. This is in the range of 90 to almost 99 percent retention and new technologies developed at Weyburn and other demonstration projects are improving resolution and detection levels. Time-lapse 3-D seismic surveys at the Sleipner gas field saline injection indicate that no detectable leakage of CO_2 into the caprock has occurred (7 million tonnes of CO_2 injected over 12 years) (Chadwick et al., 2008). Crosswell seismic surveying at the Frio test site indicates plume migration throughout the “C” Sandstone (deepest sandstone layer) injection region and successful plume confinement by the “B” Sandstone (middle sandstone layer) formation. Monitoring of site geophysical (downhole and well pressure and temperature) and geochemical (gas composition analysis and water chemistry: pH, alkalinity) parameters using primary technologies (Tables 5-1 and 5-2) confirmed the plume images obtained via seismic surveying and verified that the CO_2 plume had not breached the “B” Sandstone layer (Hovorka et al., 2005).

Table 5-2: MVA Technologies that Enable Recognition of Leakage to the Atmosphere and Shallow Subsurface in Order to Ensure 99 Percent Retention of CO_2

Primary Technologies		**MVA Goals for Geologic Sequestration**				
		Identify storage processes and confirm their efficiency.	Evaluate the interactions of CO_2 with formation solids and fluids.	Assess environmental, health, and safety impacts in the event of a leak.	Evaluate and monitor remediation efforts should a leak occur.	Assist in mediating legal disputes resulting from any impact of sequestration technology (groundwater impacts, seismic events, crop losses, etc.).
Water Quality Analysis	Groundwater Monitoring*	X		X	X	X
	Injection Fluid		X		X	X
	Formation Fluid*		X	X	X	X
	Water Level			X	X	X
CoreCollection	Geomechanical Analysis	X	X			
Wireline Logging (Well Integrity)	Temperature		X	X	X	X
	Noise		X	X	X	X
	Cement Bond (Ultrasonic)				X	X
	Density	X	X		X	X
	Gamma Ray	X	X			X
	Sonic (Acoustic)	X	X			X
	Resistivity	X	X			X
Physical Testing (Well Integrity)	Annular Pressure*			X	X	X
	Injection Volume/Rate*	X	X	X	X	X
	Wellhead Pressure*	X	X	X	X	X
	Downhole Pressure*	X	X	X	X	X
	Downhole Temperature	X	X	X	X	X
Geophysical Techniques	Seismic, Gravity, Electromagnetic Surveys, etc.*	X	X		X	X

6.0 MVA Developments for Large-Scale Tests in Various Settings

The first step towards continued use of fossil fuels within a broad climate change mitigation strategy is to demonstrate the viability of GS of CO_2 in a variety of settings. A serious effort will require large-scale tests of geological sequestration in formations with diverse characteristics that are representative of many regions throughout the United States and Canada. DOE is currently sponsoring projects to move CCS from research to commercial application. Such demonstrations are necessary to increase understanding of trapping mechanisms, to test and improve monitoring techniques and mathematical models, and to gain public acceptance of CCS. Testing under a wide range of geologic conditions will demonstrate that CCS is an acceptable GHG mitigation option for many areas of the United States.

The proposed large volume sequestration test (LVST) activities will provide valuable opportunities for R&D in carbon sequestration. Major R&D targets/activities include:

- Determination of CO_2 behavior in the subsurface.
- Comparison of multi-phase flow models with real-world data to assess predictive capabilities and refine the models.
- Determination of efficacy and detection limits of monitoring tools for CO_2 in oil and gas reservoirs and saline target formations.
- Development and application of a comprehensive risk assessment framework.
- Development and refinement of coupled models, such as reactive transport and geomechanical models.
- Refinement of regional storage capacity estimates based on LVST information.

Modeling and monitoring R&D targets for these projects include: (1) assessing the sweep efficiency as large volumes of CO_2 are injected to better quantify capacity; (2) quantifying the pressure effects and brine movement though heterogeneous rock to better understand the significance of these effects on capacity, monitor pressure, and brine migration; (3) quantifying inter-well interactions as large plumes develop, focusing on interaction of pressure, heterogeneity, and gravity as controls on migration; (4) better understanding pressure and capillary seals; (5) developing and assessing the effectiveness of available and novel monitoring tools; and (6) assessing how monitoring tools can be used efficiently, effectively, and hierarchically in a mature monitoring environment.

Critical to the successful implementation of this approach is the development of a robust MVA program, including evaluating and determining which monitoring techniques are most effective and economic for specific geologic situations; this information will be vital in guiding future commercial projects. The monitoring programs of five GS projects taking place in the United States are outlined below. These projects are sited in areas considered suitable for GS and are employing robust monitoring programs (for research purposes) to measure physical and chemical phenomena associated with large-scale CO_2 injection. The five selected projects are:

1. **Gulf Coast Mississippi Strandplain Deep Sandstone Test (Moderate Porosity and Permeability):** GS test located in the southeast portion of the United States will be conducted in the down dip "water leg" of the Cranfield Unit in Southwest Mississippi. Large volumes of CO_2 from a natural source will be delivered by an established pipeline.
2. **Nugget Sandstone Test (Significant Depth, Low Porosity and Permeability):** LVST in the Triassic Nugget Sandstone Formation on the Moxa Arch of Western Wyoming. The source of the CO_2 is the waste gas from an He and CH_4 production facility.
3. **Cambrian Mt. Simon Sandstone Test (Moderate Depth, Low Porosity and Permeability):** A large-scale injection test in Illinois is being conducted in the Midwest Region of the United States. The main goal of this large-scale injection is to implement a geologic injection test of sufficient scale to generate understanding of injectivity, capacity, and storage potential in reservoir types having broad importance across the Midwest Region

4. **San Joaquin Valley Fluvial-Braided Deep Sandstone Test (High Porosity and Permeability):** Large-scale injection of CO_2 beneath a power plant site into a deep saline formation (the Olcese and/or Vedder sandstones) of the San Joaquin Valley, California.

5. **Williston Basin Deep Carbonate EOR Test:** CO_2 sequestration in conjunction with EOR in select oil fields in the Williston Basin, North Dakota. A minimum of 500,000 tons per year of CO_2 from an anthropogenic source (PC plant) will be injected into an oil reservoir in the Williston Basin.

Each site varies significantly in overall site geology, including target formation depth, formation porosity, permeability, temperature, pressure, and seal formation (see Table 6-1). MVA packages selected for commercial projects will be tailored to site specific characteristics and geological features (Benson et al, 2004). The MVA packages for these case studies were selected to maximize understanding of CO_2 behavior and to determine which monitoring tools are most effective across different geologic regimes (as opposed to tailoring a site-specific MVA package).

An overview of the MVA tools for each case study project is presented in Table 6-2. Although each project site has distinct geology, the projects employ many of the same Primary Technologies. Many Secondary and Potential Additional Technologies are used to expand the information obtained from the Primary Technologies. The MVA protocols outlined herein do not replace or supersede statutory or regulatory requirements for protection of human health and the environment.

Table 6-1: Comparison of Site Geology for Each Case Study Project

Project	Geographic Location	Geologic Formation	Geologic Storage Class	Reservoir Type	Attributes						Injection Schedule	Geologic
					Porosity	Permeability	Thickness	Avg. Depth	Temperature	Pressure	Tons CO_2	Seal
Gulf Coast Tuscaloosa Deep Sandstone Test	Mississippi	Lower Tuscaloosa	Fluvial Sandstone	Saline	15% to 30%, avg. 20%	50 to 1,000 mD	150 to 250 ft	10,000 to 10,500 ft	220 °F to 270 °F	4,300 to 4,400 psi	1.5 MM Total	Tuscaloosa Marine (300 ft) Austin Chalk Midway Fm
Nugget Sandstone Test	Southwest Wyoming	Nugget Sandstone	Eolian Sandstone	Saline	12% to 15%	70 to 300 mD	150 to 250 ft	11,000 to 13,000 ft	209 °F	3,850 psi	1 MM/yr, 3 MM Total	Twin Creek Limestone (500 ft) Strump-Pruess Shale (1,000′)
Mt. Simon Shallow Sandstone Test	Ohio	Mt. Simon Sandstone	Strandplain Sandstone	Saline	8% to 18%	<1 to 300 mD	200 to 300 ft	3,300 to 3,600 ft	88 °F	1,435 psi	.28 MM/yr, 1.2 MM Total	Eau Claire Shale (500 ft)
San Joaquin Valley Fluvial-Braided Deep Sandstone Test	California	Olcese and Vedder	Fluvial-Braided	Saline	20% to 40%	31 to 2,400 mD	500 to 800 ft	8,000 to 9,000 ft	Not Available	Not Available	0.25 MM/yr, 1.0 MM Total	Freeman Siltstone, Jewett Shale (1,000 ft)
Williston Basin Deep Carbonate EOR Test	North Dakota	To be Determined	Shallow Open Shelf Carbonate	EOR	To be Determined	To be Determined	To be Determined	>10,000 ft	To be Determined	To be Determined	0.5 MM to 1.0 MM Total	Charles Formation

Table 6-2: Comparison of MVA Tools Used by Each of the Selected Case Studies

Monitoring Techniques			Gulf Coast Tuscaloosa Sandstone Injection	Deep Eolian Nugget Sandstone Injection	Cincinnati Arch Mt. Simon Sandstone Injection	San Joaquin Valley Fluvial-Braided Sandstone Injection	Williston Basin Shallow Shelf Open Carbonate EOR Test
Atmospheric	**Primary Technologies**	CO_2 Detectors	X			X	X
	Secondary Technologies	Laser Systems and LIDAR				X	
	Potential Additional Technologies	Eddy Covariance		X		X	
		Advanced Leak Detection System					
		Isotopes	X		X	X	X
Near-Surface	**Primary Technologies**	Geochemical Analysis	X	X	X	X	X
	Secondary Technologies	Advanced Water Quality	X		X		X
		Aerial Photography					
		Shallow 2D Seismic		X			
		Soil and Vadose Zone Gas Monitoring	X	X	X		
		Flux Accumulation Chamber	X			X	
	Potential Additional Technologies	Tracers	X		X		X
		Conductivity					
		Induced Polarization					
		Self-Potential					
		Tiltmeters			X		X
		Remote Sensing (CIR, SAR, Hyperspectral)		X	X		
Subsurface	Primary Technologies	Water Quality Analysis	X	X	X	X	X
		Wireline Logging	X	X	X	X	
		Physical Testing	X	X	X	X	X
	Secondary Technologies	Acoustic (2D and 3D) Seismic	X				
		VSP	X			X	
		2D and 3D Seismic	X	X	X		
		Geochemistry Analysis	X	X		X	
		Wireline Logging (Optical, Gamma Ray, CBL, etc.)	X				
	Potential Additional Technologies	Crosswell Seismic	X	X	X	X	
		Microseismic	X	X	X	X	X
		EMIT					
		ERT					
		Magnetotelluric Sounding					
		Resistivity and EM	X	X			
		Induced Polarization					
		Time-lapse Gravity Survey		X			

6.1 Gulf Coast Mississippi Strandplain Deep Sandstone Test (Moderate Porosity and Permeability)

A GS test located in the southeast portion of the United States will be conducted in the down dip "water leg" of the Cranfield unit. A large volume of CO_2 from a natural source will be delivered by an established pipeline. The goals of the project are to: (1) assess the feasibility and logistics of injecting 1.1 million tons (1 million metric tons) of CO_2 per year into a regionally significant brine-bearing formation in the Gulf Coast; (2) monitor the subsurface movement of CO_2 and its storage as dissolved and residually trapped phases along the flow path; and (3) document lack of harm to surface resources through close monitoring of injection activities. High purity, commercial-grade CO_2 will be transported through a pipeline from a natural source to the site.

The unique features of this project are that it involves injection of natural source CO_2 into a deep (~10,000 ft [3,050 m]) saline sandstone formation of moderate porosity (20 percent average) and permeability (up to 1,000 millidarcy [mD]). This project will provide data on the behavior of CO_2 in this type of venue and help validate mathematical models.

6.1.1 Target Formation

The target formation is the massive sandstone of the Lower Tuscaloosa Formation, a Cretaceous age sandstone saline reservoir that occurs in the subsurface along the Gulf of Mexico Coastal Plain from Western Florida to Texas (where it is defined as the Woodbine Formation). The Lower Tuscaloosa contains an upper section of alternating shales and sands and a sand-rich basal section. The formation was deposited during a major period of global sea-level rise, and its deposition has been interpreted as an upward gradation from fluvial and deltaic sedimentation to shelf deposition (alternating sands and shales) (Mancini, 1987). The well-sorted, clean, coarse-grained nature of the Massive Sand is a result of this environment and makes it an ideal candidate for injection due to its moderate permeability and porosity.

The Lower Tuscaloosa Formation occurs at 10,000 to 10,500 feet at the site location along the flanks of the Cranfield oil field with reservoir pressures of about 4,300 to 4,400 pounds per square inch (psi). The lower Tuscaloosa at Cranfield is well characterized by more than 70 wireline logs, sidewall cores, whole cores, a well known production history, and a 3-D seismic survey. The lower complex flow system, locally known as the "E and D" sandstones and conglomerate, is 10 to 50 ft (15 m) thick, highly heterogeneous, and complexly incises fluvial deposits. Red and gray shales and siltstones form within lower Tuscaloosa flow-unit barriers, isolating the younger sand bodies. These units are less amalgamated, and therefore sand is less continuous.

The mineralogy of the lower Tuscaloosa complex, including conglomerate, coarse sandstone, muddy sandstone and mudstone, carbonate and chlorite cementation, are common and variable (MDEQ Bulletin 108). The permeability of the lower Tuscaloosa varies from 50 to 1,000 mD (GSA Bulletin 104). The Gulf Coast Basin contains a thick interval of sandstones and shales, which were deposited over a series of transgressive-regressive cycles from the Jurassic Period to the present. Formations generally thicken towards the Gulf and offshore and occur in thicknesses of up to 20,000 feet.

The seals for this project have demonstrated prior retention of oil and gas in the structure. Local seals within the lower Tuscaloosa have confined oil to the lowermost sands. Regional seals, including the middle Tuscaloosa marine shale, the Austin Chalk, and the Midway Formation, are present at Cranfield and are presumed to function as seals in the saline aquifer, as well as over the producing field, because they have retained hydrocarbons. Low permeability carbonate and shale form a seal beneath the injection interval.

6.1.2 Site Characterization

Detailed information that can be applied to this test from previous field investigations in the area is being assessed. A 3-D seismic survey adds coverage into the saline aquifer part of the field that was not available and enhances the inter-well detail needed to better interpret structure and stratigraphy. Work conducted during the investigation phase will include the assessment of new down dip injection wells by using data from coring, core analysis, and open-hole logs available for the first time from the saline portion of the Tuscaloosa Formation. To develop an interpretable and significant research result from monitoring the CO_2 flood, an integrated program will be employed, beginning with characterization and extending through several types of predictive modeling, to monitoring planning, injection strategy, baseline monitoring, injection, and post-injection monitoring. It is important to use modeling to assess uncertainties that will result from data collection efforts and to focus data collection on reducing key uncertainties.

6.1.3 Risk Assessment and Mitigation Strategy

CO_2 injection is a low risk experiment because nearby production in the oil rim will minimize pressure buildup and will influence CO_2 migration; therefore, a low-budget risk assessment approach will be implemented.

Mitigation will follow normal oil field processes and best practices. Substandard well performance (poor injectivity or non-conformance) will be corrected by well handling with dense “kill” fluids and workover. Wellhead pressure will be monitored to assure that injection occurs below fracture pressure. While considered to present minor risk, potential complications include: (1) CO_2 deliverability through the pipeline, which is a new retrofit; (2) injectivity below expected rates in the saline part of the reservoir; and (3) logistical and timeline mismatches. The project team will work with DOE and others to develop various schedules to be prepared should a problem arise.

6.1.4 MVA Activities

A robust MVA program is anticipated. The site will be well instrumented with multiple sensor arrays. Standard, off-the-shelf technologies will be tested in this carbon sequestration application. In addition, novel tools and techniques will be tested and evaluated. The project will include an extensive program to monitor performance during its 10-year duration.

Sweep efficiency is one of the primary unknowns in assessing capacity. Sweep efficiency is estimated in DOE’s Carbon Sequestration Atlas of the United States (2008) and has a large effect on the capacity of saline formations. Methods used to measure sweep efficiency are (a) saturation measurements along wellbores, (b) crosswell measurements, and (c) special measurements—VSP and/or surface seismic. Time lapse changes compared to baseline and measurements with multiple instruments are most likely to lead to a unique solution.

Pressure and brine migration are less sensitive to heterogeneity than multiphase flow. However, improved understanding of these potential risk factors under sub-fracture injection conditions is needed. Collection of data that allows quantification of the components of pressure response (fluid flow, rock and water compression, dilatancy and tilt) in high and low permeability units is a goal. Models show that plume interactions are a major factor controlling capacity. The project setting will provide a unique laboratory to history match as saline injection wells are started. Pulsing injection and measuring bottom-hole pressure response in the signal source well and distant monitoring points is also a powerful tool for history matching. Interaction with cones of pressure reduction around producers in the oil ring will also be included.

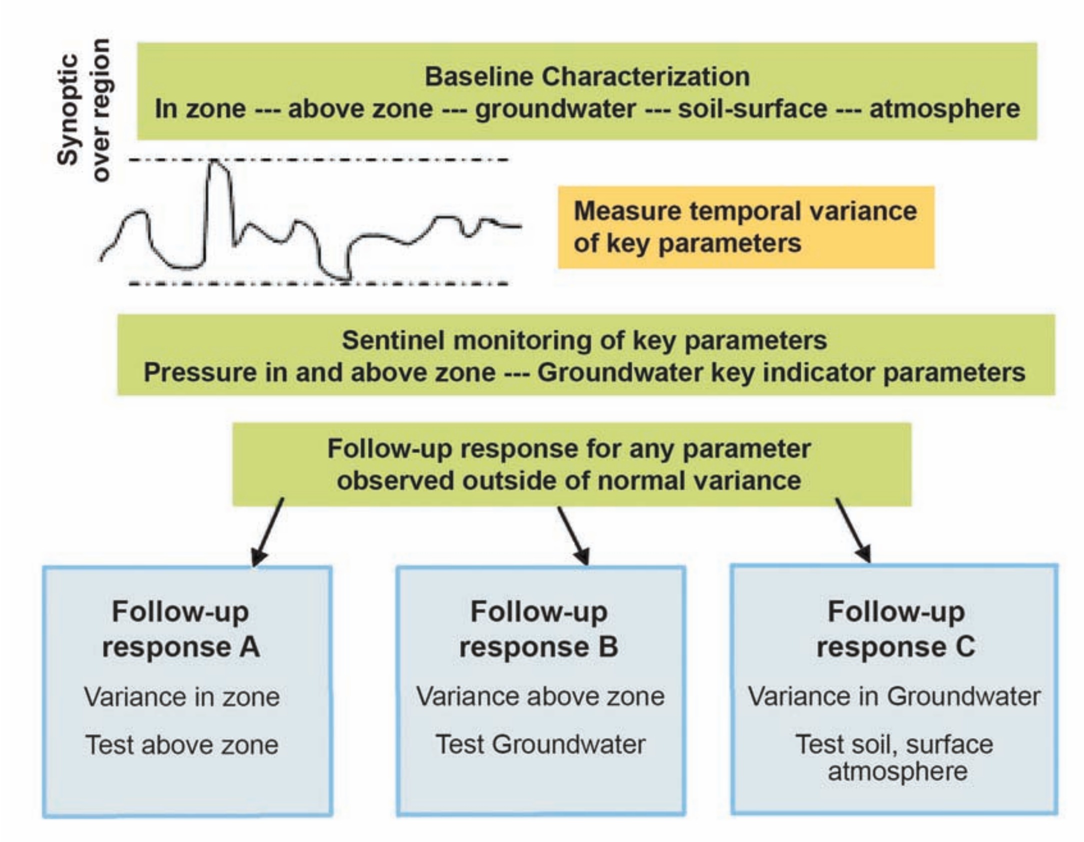

Figure 6-1: Hierarchical Monitoring Strategy

Tools are needed to better understand the performance of pressure and capillary seals. The seals at the injection site are known to hold gas; their performance under CO_2 flood will help to extrapolate this critical factor in assuring retention of CO_2 in zone.

One focus of the project is experimentation with a prototype hierarchical mature monitoring strategy (see Figure 6-1). It starts with baseline characterization, which includes measurement of the change of selected key parameters over time prior to injection and then as injection proceeds. A good temporal baseline is required to determine if the monitoring parameter changes outside of normal variability and may indicate nonconformance of the injection, such as leakage. A follow–on strategy and development of contingency plans are required for each type of non-conformance, as indicted in Figure 6-2.

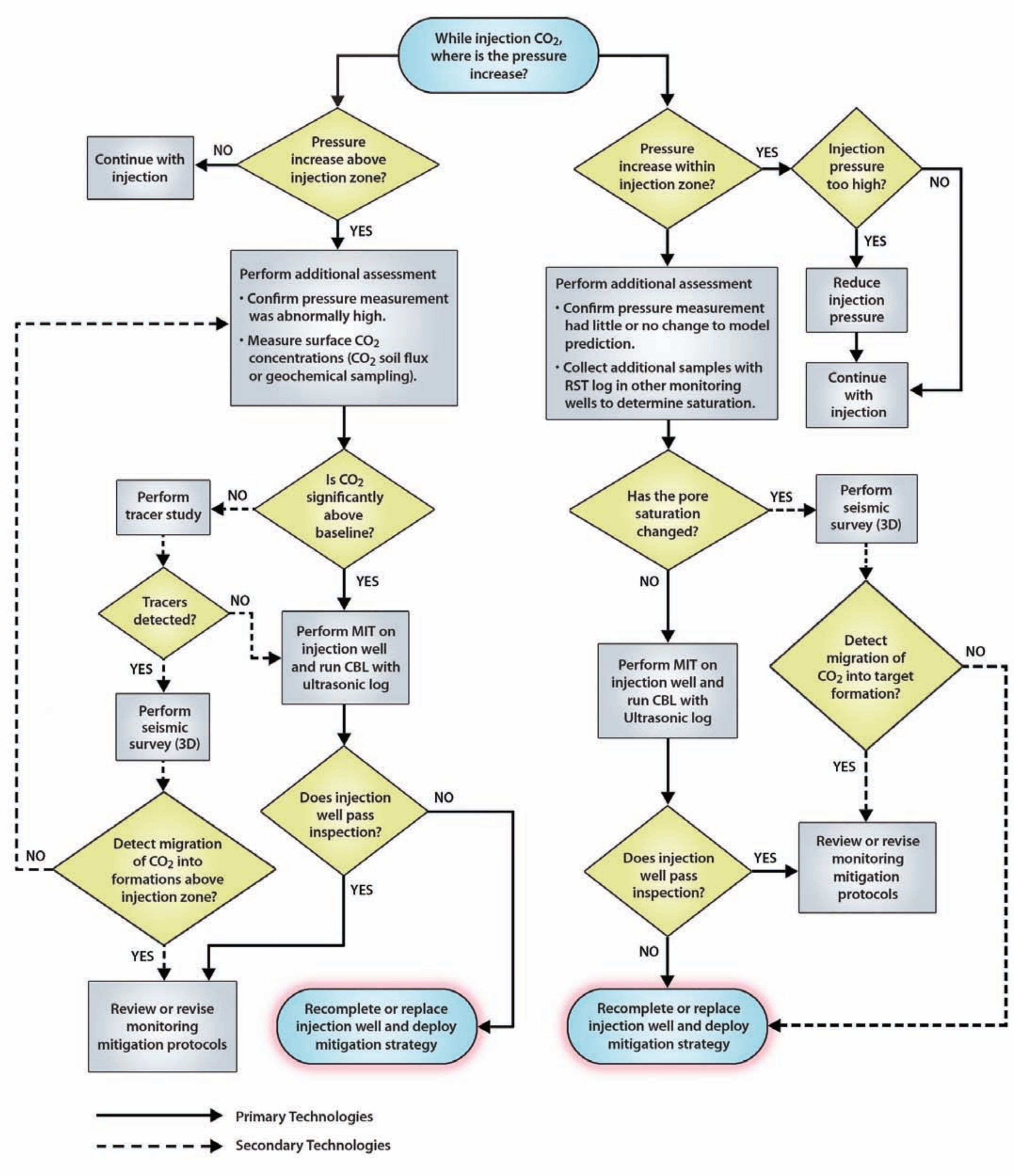

Figure 6-2: An example of contingency plans for Gulf Coast Mississippian fluvial sandstone injection during initial injection period. Major risks during injection period: pressure and buoyancy-driven flow through damaged wells or fracture networks. Probability increases over time as CO_2 quantity and pressure increases and as AoR increases.

Components of this monitoring plan include the assessment of wellbore integrity, annual assessment of the areal extent of the plume, target reservoir leakage monitoring, shallow subsurface and surface seepage monitoring, and reservoir simulation modeling. Data from monitoring will be used to calibrate and resolve inconsistencies with simulation models.

The primary monitoring strategies included for this project are aimed at accomplishing specific goals. Each task focuses on some aspect of subsurface or near-surface monitoring as can be seen in Table 6-3.

Table 6-3: Summary of MVA Plans for Gulf Coast Mississippi Strandplain Deep Sandstone Test

Measurement Technique	Measurement Parameters	Application
Introduced—noble gasses/ partitioning tracers	Dissolution of CO_2 into brine	Significant uncertainties in pressure response is the amount of CO_2 dissolved. The SECARB Early Test will deploy the U-tube to reservoir depths to obtain tracer chromatography to assess dissolution via chromatography. This is a follow-on to Frio with a larger volume and longer flow-path using the same techniques. The SECARB team recognizes that laboratory measurements of fractionation into relevant fluids and rocks is key to quantifying this test.
Produced fluid composition	CO_2 via mass, DIC, DOC; Selected major and minor cations, organics	Validation of well log and cross-well CO_2 detection, index of rock-water reaction.
Bottom-hole pressure	Pressure transducers on wireline with real-time readout	Key measurement assessing relationship between pressure field and multiphase field.
Distributed down hole temperature	Measure zones of fluid movement	Additional data to constrain flow units, especially to determine flow-unit thicknesses under relevant conditions. Also indicates well integrity.
Pulsed neutron reservoir saturation; Cased hole sonic if modeling predicts sensitive	CO_2 saturation	Distribution of CO_2 at measurements points, model match, validation and quantification of CASSM and cross-well ERT. Key input to capacity calculation term "E."
Time-lapse 3-D seismic imaging (surface deployed)	Change from baseline, only if baseline assessment shows reasonable sensitivity to the expected CO_2 saturation change	Extent of CO_2 plume: especially down-dip. May substitute VSP if sensitivity is higher.
Continuous Active Source Seismic Monitoring (CASSM); Cross-well seismic tomography	Detect timing of CO_2 movement cross the plane of measurement	History match model, with high frequency temporal records with pressure signal
Passive seismic monitoring	Assess stress distribution	Development of stress in formation
Above-zone pressure and fluid monitoring	Assess leakage signal (possible through well completions-poor cement bond)	Continuation from Phase II to obtain long record (if Phase II results justify)
Cross-well electrical resistance tomography (ERT)	Improve measurement of saturation; will be used if proves feasible and economic	Tool development will extend tie range of cross-well measurement of saturation and improve the rigor of history match and seismic inversion.
Subsurface deformation	Tilt; Measurements at surface to assess depth-effectiveness of tool under high injection rates	Quantify geomechanical effects on storage formation as part of pressure-field assessment.
$C0_2$ land surface-soil gas assessment	Measure natural CO_2 fluxes—aquifer-vadose zone-soil-land-surface and atmosphere in depth over time.	Determine sensitivity of these techniques under regional conditions. Possible follow-on-tracer test to validate hypothesis.
Aquifer monitoring	Alkalinity, DIC, DOC, isotopes, chloride selected cations and anions.	Assessment of method in compact possibly contaminated setting, directly regulated recourse. Possible follow-on-tracer test to validate hypothesis.

6.2 Nugget Sandstone Test (Significant Depth, Low Porosity and Permeability)

The goal of this LVST is to demonstrate that the Nugget sandstone in the LaBarge Platform, Wyoming, and other analogous sandstones are a viable and safe target for sequestration of a large portion of the northwestern United States' CO_2 emissions. This test will improve understanding of injectivity, capacity, and storability in a regionally significant formation and promote commercialization of carbon sequestration.

This project will conduct an LVST in the Triassic Nugget Sandstone Formation on the Moxa Arch. The test will inject approximately 1 million tons of CO_2 a year for three years into the saline aquifer at depths of 11,000 to 13,000 feet. The source of the CO_2 is the waste gas from an He and CH_4 production facility. CO_2 will be injected into the Nugget Formation utilizing a single vertical wellbore. Injectivity into the Nugget Formation will be approximately 5,360 tons/day according to testing in the target formation. Since the mid-1970s, the vicinity of the site has been, and continues to be, subjected to significant oil and gas exploration and production. Regional Characterization activities include acquiring and analyzing new data, field measurements, refining capacity estimates, and collaboration and data sharing with industry and agencies. The regional characterization work will include geologic, terrestrial, economic, and geographic information system (GIS) components.

The unique features of this project are that it involves injection of by-product CO_2 from He and natural gas production into a deep (~12,000 ft [~3,700 m]) saline sandstone formation of low porosity (12 to 15 percent) and permeability (up to 300 mD). This project will provide data on the behavior of CO_2 in this type of venue and help validate mathematical models.

6.2.1 Description of Target Formation

The LaBarge Platform encompasses a large structural closure at the northern limit of the Moxa Arch. The Moxa Arch is a large north-south trending anticline bound on the south by the Uinta Mountains and trending north for 120 miles before plunging beneath the leading edge of the Wyoming Thrust Belt. The west flank of the anticline dips below the Wyoming Thrust Belt, and the east flank is the western margin of the Green River Basin. The closure of the LaBarge Platform encompasses approximately 800 square miles on the northern region of the Moxa Arch. Three small, mature Nugget oil fields are present on the LaBarge Platform and produce from smaller anticlines superposed on the much larger structural feature. The Nugget Sandstone is an extensive brine aquifer located in the LaBarge Platform and extending across the remainder of the Moxa Arch and into the Green River Basin. This saline formation of the Nugget Sandstone within the closure of the LaBarge Platform is the target of this injection project. The LaBarge Platform has the potential to store a large volume of CO_2 in the Nugget Formation and takes on even greater long-term significance, as the Nugget Formation on the remainder of the Moxa Arch and within the Green River Basin is also a potential sequestration target.

The Nugget Sandstone is a Jurassic-aged regional sheet sandstone that underlies southwestern Wyoming. The thickness of the Nugget Sandstone in the area of LaBarge is approximately 650 to 700 feet. It is equivalent to the Navajo Sandstone (Utah) and has similar properties to the Tensleep Sandstone (Montana and Wyoming), Weber Sandstone (Colorado, Utah, and Wyoming), Quadrant Sandstone (Montana), and the Sundance Sandstone (Wyoming) and, thus, has important regional significance. The Nugget Sandstone was deposited as a series of sand dunes and interdunal deposits in an Eolian depositional environment. The porous sandstones that are the injection target have an average thickness of 150 to 250 feet, an average porosity of greater than 15 percent, and are highly permeable. The seal formation consists of 500+ feet of the overlying Twin Creek limestone capped by 1,000+ feet of the Jurassic Strump-Pruess shale section. These seals maintain integrity in the structurally more complex Wyoming/Utah thrust Belt and have also been proven to be an effective seal for the three small oil fields located on the LaBarge Platform. There is no reason to suspect any issues pertaining to seal integrity for CO_2 storage.

6.2.2 Risk Assessment and Mitigation Strategy

Major effort will include the development of the system level model CO_2-PENS, as well as detailed work on the integrity of wellbores and seals in the context of CO_2 storage. Other work will include dynamic fracture simulations for the risk assessment portion of the project. This work will directly assess important aspects of site performance and risk due to pressure and stress changes in fracture networks.

6.2.3 MVA Activities

MVA activities will include extensive monitoring and simulations to ensure that the injected CO_2 remains contained in the target formation. The basic well configuration will consist of a single injection well with a minimum of four installed monitoring wells. Additional monitoring capacity will depend on existing wells, if available within the plume dimensions. The fundamental direct monitoring methods employed will include soil gas surveys, geophysical detection of subsurface CO_2 (2-D or 3-D seismic, single or multi-component) and sampling of monitoring wells for geochemical indicators of the presence of CO_2. Sampling of multiple vertical intervals is planned to allow detection of CO_2 in the target formation, the overlying seal interval, and a shallow subsurface aquifer. Additional surface methodologies may include EC towers, LIDAR and IR detection tools, and hyperspectral tools, as well as traditional soil gas analysis.

Subsurface measurements will focus on borehole logs that provide physical and chemical information about the reservoir rocks and gases and fluids within the pore space. Gravity and other borehole log measurements, when measured between boreholes and during and after CO_2 injection (time-lapse), can be used to map changes in physical and chemical properties of rocks and fluids. Borehole wireline logging will also be conducted to assess geologic characteristics as a function of depth in the well vicinity.

Other subsurface methodologies may be employed, depending on specific site conditions and costs. These include downhole methods such as electrical resistance tomography, crosswell tomography, microseismic (passive), sparse array seismic in-situ probes, and syn-injection tracers. These methodologies can be used to address storage feasibility, make point measurements of state functions (P and T), and track the disposition of injected CO_2.

All surface and subsurface data from the project will be integrated using a stochastic inversion approach. Stochastic inversion is extremely well suited to integration of uncorrelated (orthogonal) subsurface data sets. It is robust, fast, handles non-linear and non-unique solutions well, and calculates the likelihood for each of multiple solutions. This approach can also be used to help plan a field monitoring network.

6.3 Cambrian Mt. Simon Sandstone Test (Moderate Depth, Low Porosity and Permeability)

The goal of this large-volume storage test is to demonstrate the ability of the Mt. Simon Sandstone, a major regional saline reservoir in the Illinois Basin, to accept and retain 1 million tons of CO_2 injected over a period of three years. The proposed site is near an ADM ethanol fermentation facility. The ethanol facility serves as the source of the injected CO_2.

The key research and development targets for the large-scale injection test relate to acceptance by the saline reservoir of the CO_2 (injectivity), ability of the reservoir to store the CO_2 (storage capacity), the integrity of the seals, and the entire process of pre-injection characterization, injection monitoring, and post-injection monitoring to understand the fate of the CO_2. These targets can be summarized under the general processes of modeling, capture, injection, and monitoring.

6.3.1 Target Formation

The thickest and most widespread saline reservoir in the Illinois Basin is the Cambrian-age Mt. Simon Sandstone. It is overlain by the Eau Claire Formation, a regionally-extensive low-permeability shale, and underlain by Precambrian granitic basement.

There are only about 20 wells in the target region of southern Illinois that reach into the Mt. Simon (greater than 4,500 feet measured depth) and many of these wells penetrate only a short interval at the top. Most of these are old wells that lack a suite of modern geophysical logs suitable for petrophysical analysis. Although comprehensive reservoir data, where injection will occur, are currently lacking, there are sufficient data to demonstrate the regional presence of the Mt. Simon. The Mt. Simon is used extensively for natural gas storage in the northern half of Illinois, and detailed reservoir data are available from these projects. The ten gas storage projects show that the upper 200 feet of the Mt. Simon has the necessary porosity and permeability to be a good sequestration target. No current seismic reflection data are available at the proposed site. The project team plans to acquire at least two new 2-D seismic reflection profiles across the proposed site.

The Mt. Simon is more than 1,000 feet thick at the site and has an average porosity, calculated from wireline logs, of about 12 percent. The top of the Sandstone at the site location lies at a depth of approximately 5,500 feet, in agreement with wells in the area that suggest that the top of the Mt. Simon would occur between 5,000 and 6,000 feet. Using a linearly extrapolated temperature gradient of 1 °F/100 ft (1.7 °C/100 m), the bottom hole temperature at 5,500 feet (1,675 m) is estimated to be about 116 ˚F (46.6 °C). To calculate the pressure at 5,500 feet (1,675 m), a pressure gradient of 0.4 psi/ft (0.083 atm/100 m) was used, because Illinois reservoirs tend to be slightly underpressured compared to the standard freshwater gradient of 0.433 psi/ft (0.09 atm/100 m). At 5,500 feet (1,675 m) the expected reservoir pressure is about 2,200 psi (149 atm).

Within the Illinois Basin, three thick shale units function as significant regional seals. These are the Devonian-age New Albany Shale, Ordovician age Maquoketa Formation, and the Cambrian-age Eau Claire Formation. There are also many minor, thinner Mississippian- and Pennsylvanian-age shale beds that form seals for known hydrocarbon traps within the basin. Just as important, the lowermost seal, the Eau Claire, has no known penetrations within a 15-mile radius surrounding the site; therefore, integrity of existing wellbores is not as important an issue as in some shallower formations. All three significant seals are laterally extensive and appear, from subsurface wireline correlations, to be continuous within a 100-mile radius of the test site. There are two secondary seals at the site. The Ordovician Maquoketa Shale is laterally continuous across the projected test site and is estimated to be over 200 feet thick at the ADM site. This shale is a regional seal for production from the Ordovician Galena (Trenton) Limestone. The Devonian-Mississippian New Albany Shale is about 140 feet thick in the ADM study area. Extensive well control from oil fields shows that this shale is a good seal for hydrocarbons; hence, it should also be a good secondary seal against the vertical migration of CO_2.

6.3.2 Site Characterization

The characterization and modeling task will be implemented according to a Performance and Risk analysis program. Based on a systemic approach, this program will allow defining the characterization, modeling and monitoring needs in order to optimize the performance of the specific site and reduce risks to a minimum. Specific site characterization tasks include:

1. System definition; specification of the boundaries of the system that will be analyzed and definition of the assessment phases (site development, operations, long-term storage).
2. Data collection and interpretation: collection of all the relevant data available from previous project phases, their interpretation, and identification of the main uncertainty areas.
3. Initial performance and risk analysis: initial characterization of the ADM site in terms of capacity, injectivity and containment (static analysis) based on the current knowledge and understanding of the storage behavior and the main risks. This study will allow identifying the information needed for a complete analysis. In particular, it may point out the need for further characterization of features or properties.

A comprehensive characterization program will be defined from the results of the initial performance and risk analysis, and be performed to properly assess the storage performance factors and evaluate risks. The effort is outlined in Figure 6-3. This will be achieved by recording two 2-D seismic lines on the roads adjacent to the injection site to pre-qualify the site on a gross basis, drilling a data well to collect data and samples, from which a full formation evaluation study will be conducted, and recording a high-resolution 3-D seismic survey for use as baseline and detailed reservoir characterization. Well testing and/or a small-scale CO_2 injection test will also be considered.

6.3.3 Risk Assessment Strategy

The relevant risk pathways addressing loss of performance (capacity, injectivity, containment) during operations and long-term storage will be identified. Existing generic databases will be cross-referenced to project-specific information and location to identify the relevant risk pathways. The risk pathways so identified will be analyzed, and selected representative scenarios will be built.

The representative scenarios identified will be analyzed in detail by means of dynamic analysis. The associated uncertainties will be estimated for sensitivity analysis. The likelihood of each representative scenario (operations and long term storage) will be assessed based on the results of the previous step, dedicated analysis/simulations, field data, and expert judgment. The consequences of each scenario will be assessed based on its impact on the relevant stakes (health, environment, properties/assets, authorities, public opinion, etc.) (scenario severity). The likelihood of each scenario will be combined with the consequence values to provide a risk estimate. The approach will be semi-quantitative and will provide the best estimate based on the current knowledge of the site and CO_2 behavior underground.

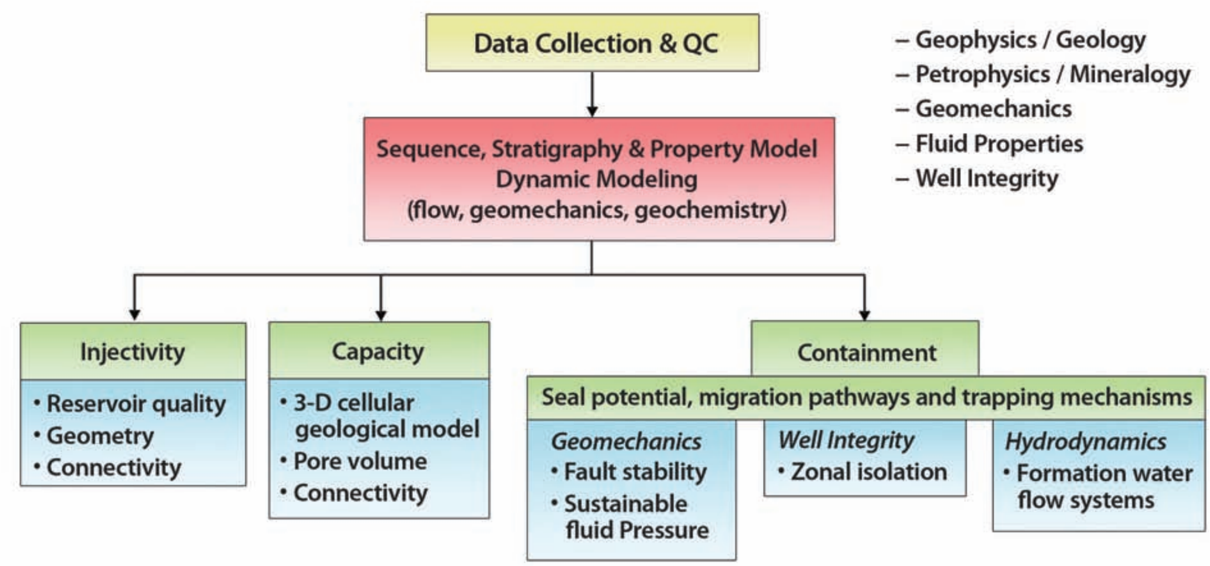

Figure 6-3: Site characterization workflow plan designed to assess injectivity, capacity, and containment.

6.3.4 MVA Activities

Initial site environmental monitoring is designed to obtain a baseline of environmental parameters for at least one year before CO_2 is injected. This monitoring will benefit from experience to date at the small-scale enhanced oil recovery (EOR) pilots at which reservoir fluids, groundwater, gases in the vadose zone, and wellbore gas were sampled and analyzed. In addition, air monitoring will take place and will assist with monitoring as injection proceeds for the large-scale saline reservoir test.

Reservoir monitoring will be baselined against a pre-injection 3-D seismic survey and possibly a pre-injection vertical seismic profiles (VSP), depending upon the results of the initial 2-D survey and the cultural constraints with respect to the layout of the 3-D survey. Geophysical techniques may include permanently placing geophones in the injection well that would facilitate microseismic monitoring and repeat VSPs. This appears especially appropriate given the cultural features on the surface. Monitoring will continue during injection and for two years post-injection.

The MVA program will have operational, verification, environmental, and mitigation components. Data collection for each of these components will occur pre-, during, and post-CO_2 injection. The operational component will provide information on the injected CO_2, injection formation, its response to CO_2 injection, and the migration of the CO_2 plume within the injection formation. The verification component will provide information to evaluate whether leakage of CO_2 through the caprock seal is occurring, and the environmental component will determine whether CO_2 is seeping into the biosphere. The mitigation component will describe action trigger levels to initiate additional monitoring and/or increase monitoring frequency to verify that CO_2 leakage is occurring, the extent of leakage, and to provide actions to reduce or curtail the leakage.

Tailoring the MVA program to the specific site with a yearly review will allow the monitoring program to focus on the greatest potential risks, as well as provide for a cost effective use of monitoring resources. Because of the limited data available regarding the heterogeneity of the injection formation's properties, it is envisioned that the program will be dynamic such that, as information is collected through the life of the project, monitoring can be directed toward areas that pose the greatest risk (Benson et al., 2004). Extensive monitoring will initially occur at the injection well and in the anticipated plume footprint formed by the injection of 330,000 tons CO_2 annually for three years. Based on data collected during the initial year of CO_2 injection, with emphasis on 3-D seismic surveys to determine plume size and migration, the MVA program will be evaluated to ensure that data collection is occurring in areas where the plume is located and where it will migrate during the project period.

Multiple techniques will be required to monitor CO_2 migration in the injection formation and to assess the potential for CO_2 to breach the confining layer. Benson et al. (2004) provide an excellent summary of the most common potential techniques that could be used in CO_2 sequestration projects. Because CO_2 sequestration is a fairly new concept, there are very limited field scale projects, so these techniques have not been fully tested and evaluated as to their suitability for this application. Table 6-4 provides a summary of potential monitoring techniques that could be used in each component of the monitoring program. A composite of these techniques will provide information regarding the (1) atmospheric, soil pore gas, groundwater, and formation CO_2 and hydrocarbon gas concentrations and isotopic signatures, (2) integrity of injection, production, and abandoned wells, (3) vegetative cover profiles in the vicinity of the site, (4) geophysical characterization of the injection formation and shallower geologic formations, and (5) shallow groundwater and formation geochemistry.

In addition CO_2 transport model simulations in conjunction with operational monitoring, that includes injection volumes, injection well pressures, injection formation temperatures, and annulus pressures, will provide the information necessary to determine whether there is potential CO_2 leakage through the caprock. Modeling of the shallow groundwater will provide insights into groundwater flow directions and the potential for transport of groundwater that may be impacted by the CO_2 injection process and require migration off site. Geochemical modeling will provide insights into the reactions and products of injected CO_2

with formation matrix and fluids. Inconsistencies between field data and model predictions, which may suggest a leak, would trigger another level of monitoring to determine the CO_2 plume location.

The potential movement of CO_2 in the unsaturated zone and the near-surface environment—in addition to atmospheric releases—will be evaluated using the multicomponent and multiphase reservoir simulator TOUGH2 (transport of unsaturated groundwater and heat) (Pruess et al., 1999). TOUGH2 will be coupled with LSM, (land-surface model) to account for plant-carbon dioxide interactions (Bonan, 1998).

Reactive transport and geochemical modeling of the fate of injected carbon dioxide and its effects on the chemical and mineralogical composition of the injection formation and confining layers will be studied using NUFT (non-isothermal/thermal, unsaturated/saturated, flow and transport model), a collection of databases and software (Nitao, 1998). The geochemical database is applicable to a pressure range of 1 to 4,935 atm, and a temperature range of 32 to 1742 °F (0 to 1,000 °C). The geomechanical model LDEC (distinct-element geomechanical model) will be used in conjunction with NUFT to predict pressure-stress relationships. LDEC will be applied to assess cap-rock geomechanical deformation by simulating the evolution of microfractures created by the pressure of injected carbon dioxide (Johnson et al., 2004).

Table 6-4: Summary of MVA Program to be Implemented at Large-Scale Injection Sites.

Monitoring Technique	**Monitoring Period**		
Pre-CO_2 Injection	During Injection		Post-CO_2 Injection
Air quality monitoring Measure CO_2 concentrations at injection well Measure CO_2 fluxes using Eddy Covariance	 X X	 X X	 X X
3-D seismic surveys, Vertical Seismic Profiles (VSP)	X	X	X
Injection well logging	X		X
Measure pressure, gas content and isotopic signature in injection well	X	X	X
Monitor formation pressure, temperature, gas content, and formation fluid chemistry	X	X	X
Conduct High Resolution. Electrical Resistivity surveys	X	X	X
Measure CO_2 concentrations and isotopic signature in vadose zone	X	X	X
Determine shallow groundwater flow direction, install monitoring wells, geophysical logs, measure water quality	X	X	X
Measure water quality from potential residential and other potable water wells	X	X	X
Aerial imaging of injection site using satellite imagery	X		X
Measure CO_2 injection rates and volumes		X	
Isotropic characterization of injected CO_2		X	
Model potential geochemical reactions and CO_2 migration in injection formation, cap rock, and land surface	X	X	X
Add perflourocarbon tracer to injected CO_2 and monitor for tracer in vadose zone soil gases and groundwater.	X	X	X
Measure CO_2 surface fluxes using accumulation chambers	X	X	X
Monitor microseismic activity near injection well	X	X	X
Wireline logs to assess subsurface characteristics	X	X	X

6.4 San Joaquin Valley Fluvial-Braided Deep Sandstone Test (High Porosity and Permeability)

This project consists of an LVST at a power plant site in the Western United States. The location, which will provide both the CO_2 and the injection site, is of particular interest because it overlies the San Joaquin Basin, part of the Great Valley province, which has the largest potential storage capacity in California.

The test will store 250,000 tons of CO_2 per year for four years in a deep saline formation beneath the power plant. Clean Energy Systems' (CES) Zero-Emissions Power Plant (ZEPP-1) will supply the CO_2 for the test. Pre-operational phase activities will include permitting, public outreach, site characterization, and infrastructure development. Three formations beneath Kimberlina are possible targets: the Stevens at 7,000 feet, the Olcese at 8,000 feet, and the Vedder at 9,000 feet. Characterization activities will include reservoir modeling and a capacity assessment of these formations. An appraisal well will be developed and a test injection will be conducted using a smaller quantity of CO_2. The actual selection of the target formation(s) will depend on the results from these early characterization activities.

This will be one of the first large-scale GS efforts in the United States storing CO_2 emitted by an industrial or power generation operation. The site will be thoroughly characterized before any injection begins, providing information for later commercial activities in which larger amounts of CO_2 may be sequestered. As the program develops, new methods for monitoring and validating capture and storage will be developed, demonstrated, and certified.

A major aspect of developing new monitoring and modeling technologies and systems will be to accurately determine the amount of CO_2 being stored and retained. All aspects of the injection process will be rigorously monitored to check for leakage and to validate the volume of stored CO_2. This information will be critical in the development of any future measuring and monitoring systems for valuing and providing carbon credits for similar projects.

The unique features of this project are that it involves injection of CO_2 recovered from power plant flue gas into a deep (~8,500 ft [~2,600 m]) saline sandstone formation of high porosity (up to 40 percent) and permeability (up to 2,400 mD). This project will provide data on the behavior of CO_2 in this type of venue and help validate mathematical models.

6.4.1 Target Formation

The site is located in the southern portion of the San Joaquin Basin in California. The focus of the study is injection into saline formations, but the presence of nearby oil fields that could be potential EOR locations is an important consideration for future commercial business development.

There are two sandstone units of primary interest—the Olcese and the Vedder. The Olcese, at a depth of about 8,000 feet (2,400 meters), is a regionally continuous, fluvial-estuarine unit of moderate injectivity. Its thickness at the site is up to 800 feet (240 meters). The Vedder, at a depth of 9,000 feet (2,700 meters), is also regionally continuous. At the site is a braided stream unit with a thickness up to 500 feet (150 meters). The combined storage estimate for the two units in the area beneath the site is about 440 million tons (400 million metric tons) of CO_2 in dissolved and residual capacity and about 1,650 million tons (1,500 million metric tons) of CO_2 in physical capacity. Thick shale units provide a good overlying seal.

Definition of the lithology near the site was provided by logs from site reference wells. The wells provided sufficient data to enable target sequestration formations and capacity estimates. The shallowest injection target is the 400-foot thick Stevens Sandstone located at about 7,000 feet depth. The depositional environment for the Stevens is a deep-water fan. Below the Stevens is the Olcese and below that is the Vedder.

6.4.2 Site Characterization

The LVST will take place on a 40-acre site in which the California ZEPP-1 and associated CO_2 storage and injection systems will be constructed. The site is located in the southern portion of the San Joaquin Basin. The largest potential storage capacity for saline formations in the region is in the Central Valley.

Successful GS of CO_2 requires thorough site characterization, especially for storage in saline formations that have not previously been considered an economic resource, as well as a clear understanding of the processes and mechanisms by which CO_2 is transported and trapped. A potential storage site must have the capacity to accept a large quantity of CO_2 and the ability to effectively trap the CO_2 for a long time, thus demonstrating the economic feasibility of the project and its safety. A geologically realistic mathematical model of the multiphase, multi-component fluid flow produced by CO_2 injection is indispensable for determining the viability of a potential storage site, because capacity and trapping ability are both strongly impacted by the coupling between buoyancy flow, geologic heterogeneity, and history-dependent multi-phase flow effects, which is impossible to calculate by simpler means. Modeling may also be used to: (1) optimize CO_2 injection by assessing the impact of various parameters, such as rates, volumes, and depths; (2) choose monitoring sensitivity and range by providing the expected formation response to CO_2 injection; and (3) assess the state of understanding by comparing model predictions to field observations. The following describes the site characterization activities that will take place during the three phases of the project:

Site Characterization Phase: Regional geological information will be used to build an initial mathematical model of the storage site, including insights from oil field models of nearby petroleum resources. Data acquired from the first well drilled will be used to improve the model. Core data will be used to obtain estimates of permeability and porosity, fluid samples to assess water chemistry, well-test data to infer field-scale permeability, flow geometry, and boundaries of storage formation. If ambiguous results are obtained, alternative models will be developed to bound possible behavior.

Data acquired from the second well will be used to improve the model and assess variability and continuity between the two wells. As was the case with the first well, if ambiguous results are obtained, alternative models will be developed to bound possible behavior. The planned CO_2 injection will be modeled to assess the capacity of storage formations.

Injection Phase: The injection phase will include modeling of actual CO_2 injection using all available models. Modeling results will be compared to field observations:

- Pressure response at injection and observation wells
- CO_2 distribution in injection well (RST, sampling)
- CO_2 arrival at observation well (RST, sampling)

Second-generation model(s) will be generated based on incorporating lessons learned from comparison to field observations. This new model(s) will be used to simulate multiple years of CO_2 injection and storage.

Post-Injection Phase: Modeling of the injected CO_2 plume using the improved model in order to predict plume fate and transport over hundreds of years.

6.4.3 Risk Assessment and Mitigation Strategy

Risk assessment will be a key ongoing activity that will drive the future activities of the project. At each project decision point, the risk assessment will be reviewed, and the decision to proceed to the next phase will depend on the ability of the project partners to manage the assessed risks.

The plan is to inject 250,000 tons of CO_2 per year for four years into the saline formations. The geology, structure, tectonics, and reservoir properties of this subsurface volume are well recognized from experience with drilling and production from nearby oil fields. This geology makes prediction of injectivity, injection-induced pressure increases, brine flow pathways, CO_2

migration, and trapping behavior relatively straightforward, and the general effects and potential impacts of the injection of CO_2 can be anticipated. First, CO_2 injection will increase pressure in the formations, altering the ambient stress state and potentially causing induced seismicity (micro-earthquakes) during injection activities. Second, CO_2 injection will displace saline groundwater in the formation. Displaced brine will follow the path of least resistance and, depending on the magnitude and direction of displacement, saline groundwater could affect shallower aquifers or hydrocarbon reservoirs. Third, injected CO_2 will tend to migrate under buoyancy forces, generally upward along the path of least resistance. During migration, CO_2 will dissolve in formation waters and undergo residual phase trapping, thereby attenuating the migration rate.

To constrain risk assessment and mitigation, it is essential to target some fraction of characterization efforts toward obtaining information about the most important features and properties relevant to evaluating potential impacts. For example, pre-injection testing to determine injectivity to minimize the potential for induced seismicity for a given planned injection rate. Hydrologic well testing to determine the extent of connectivity of the injection zone with shallower aquifers will help establish the extent and effectiveness of sealing formations. Artificial flow pathways created by exploration and water production wells need to be identified and evaluated. Historical records of water or HC seepage in the area may also be useful in understanding flow pathways between reservoirs and the near-surface environment. Finally, fluid sampling and analysis of deep and shallow HC and aqueous, gas, and liquid phases could be useful to establish whether flow paths exist from the deep subsurface to shallower formations. Fluid analyses could include bulk composition, trace gases, and isotopic composition to establish relationships between the fluids, their origins, and their ages.

Consideration of the results of the risk assessment will allow prioritization of mitigation planning. For example, a high risk of CO_2 migration up abandoned exploration boreholes in the area would point to the need for a plan to mitigate this potential conduit. Similarly, contamination of shallow potable water by CO_2, although highly unlikely, may prove to be the highest risk of several very low risk events. As the highest risk event, a plan to produce CO_2 charged water and re-inject it in deeper formations, or to otherwise stop the CO_2 migration from entering the aquifer, may be needed. Planning for near-surface mitigation measures may also be needed, even though the probability of such an event is exceedingly small, because the potential impact would be large given the urban setting. Near-surface mitigation might include capping of leaking wells and establishing an exclusion zone around a seep until it can be sealed or stopped by subsurface fluid withdrawals.

6.4.4 MVA Activities

Monitoring the injection of CO_2, pressure buildup, and associated plume migration will be an essential component of the project. First and foremost, monitoring will be used to detect and identify any safety hazards or environmental risks associated with the demonstration project. Data collected on rates of CO_2 plume migration, pressure buildup, and geochemical interactions will also provide valuable scientific information that will be used to refine and enhance computer models that predict storage performance.

Monitoring will begin during the characterization phase of the project and continue over the entire nine-year duration of the project. The monitoring program will be carried out in three phases, in conjunction with the activities being carried out at the site, namely the pre-operational phase, operational phase and closure phase of the project. During the preoperational phase, the geology of the site is characterized; the environmental, health and safety risks are identified; baseline conditions are established; small-scale injection tests may be conducted to understand and help optimize storage processes and injection operations; the injection operation is defined; monitoring plans are developed; environmental and operational permits are obtained; injection wells are drilled;

and surface facilities are constructed. During the operational phase of the project, which is expected to last four-years, CO_2 will be injected into the reservoir; surface facilities and injection rates will be monitored; the location of the plume will be tracked; and other monitoring activities will be conducted. The closure phase of the project begins when CO_2 injection has stopped. This phase of the monitoring program will be used as a confirmatory period to detect continued movement of the plume, detect any potential leakage, and to assess whether the storage project is performing as expected.

Computer simulation with the TOUGH2 and TOUGHREACT models will also be used throughout all phases of the project. During the pre-operational phase, simulation models will be used to predict plume migration and the effectiveness of solubility, residual gas (capillary) and mineral trapping. During operations, comparison between simulated and monitored plume migration will be used to refine and calibrate the model—then update forecasts of plume migration. This iterative approach will be used to develop confidence in predictions of plume behavior. During the post-operational phase, a similar iterative approach will be used to predict post-injection plume behavior—with a primary focus on quantifying the secondary trapping mechanisms that will eventually immobilize the CO_2. TOUGH2 and TOUGHREACT have both been used worldwide for simulating GS of CO_2 and are acknowledged to be among the best models for simulating GS of CO_2 in brine formations.

Specific objectives of the monitoring program are to:

- Obtain baseline data on reservoir pressure, water quality, CO_2 fluxes from the land surface to the atmosphere and seismic activity.
- Quantify the amount of CO_2 injected into the saline reservoir.
- Monitor the pressure buildup in the saline reservoir.
- Assess the condition of the injection well.
- Detect induced seismicity associated with CO_2 injection.
- Track migration of the injected CO_2 plume in the storage reservoir.
- Detect potential leakage of CO_2 out of the storage formation to overlying strata.
- Detect brine displacement associated with CO_2 injection.
- Measure CO_2 fluxes from the land surface into the atmosphere.

Information will be obtained from a comprehensive suite of measurements which will provide sufficient information to judge the safety and security of the saline reservoir demonstration test.

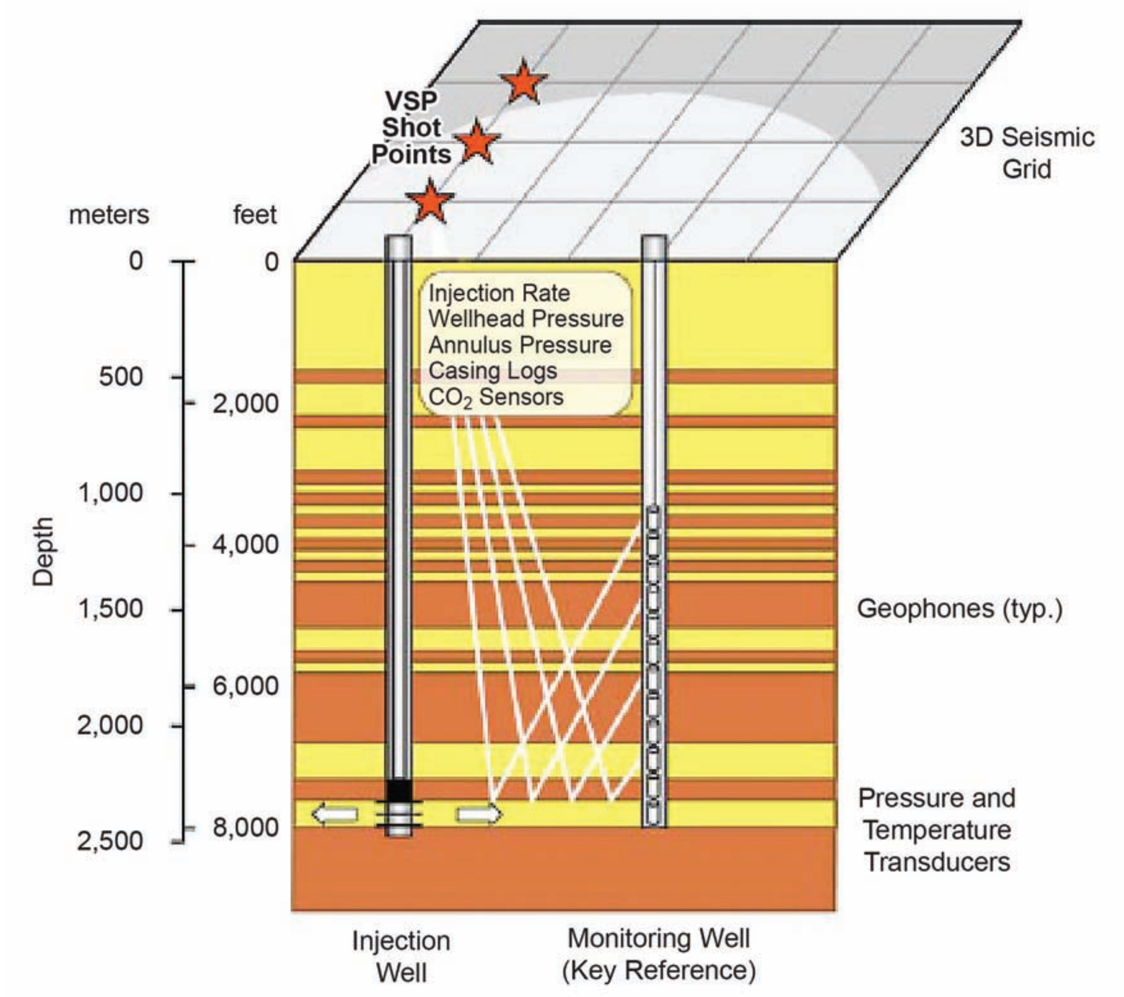

Figure 6-3: Schematic Showing Overall Monitoring Approach for Saline Formation LVST

An overall schematic of the monitoring approach is illustrated in Figure 6-4. Measurements in the storage reservoir will be acquired from the injection well and a purpose-built monitoring well. Plume tracking will be carried out using a combination of direct measurements from the injection and monitoring well and indirect observations using seismic imaging. In particular, walk-away VSP will be used annually to monitor the footprint of the plume as it migrates away from the injection well. Monitoring for leakage out of the primary storage reservoir will be carried out using direct observations from the injection and monitoring wells, as well as from seismic imaging. Surface flux monitoring data will be obtained from a combination of flux chamber measurements, wellhead CO_2 sensors, and flux towers.

The monitoring program will be generally based on the "enhanced monitoring package" outlined in the IEA Greenhouse Gas Programme (IEA GHG) sponsored project described in Benson et al. (2005b). This general approach will be augmented with recent advances in monitoring, particularly, high resolution real-time seismic monitoring that has been developed as part of the Frio Brine Pilot (Daley et al., 2007) and surface monitoring technology developed as part of the ZERT Project (Lewicki et al., 2007a). Advances in monitoring technology developed by DOE's RCSP Program will also be included in the program.

The proposed monitoring program for each phase of the project is summarized in Table 6-5 and compared to the "basic" and "enhanced" monitoring packages recommended in Benson et al. (2004). All of the elements of the "basic" monitoring program are included in the proposed monitoring plan, and most of the elements of the enhanced monitoring plan are also included. In addition, several new approaches have been added that are briefly described below.

Wells Logs: A suite of well logs will be run as part of the characterization program that will also provide baseline information for the monitoring program. Logs of particular importance for ongoing monitoring include RST, formation resistivity, sonic log and CBL, and pressure and temperature. At a minimum, the logs will be collected to provide baseline data for

Table 6-5: Basic and Enhanced Monitoring Packages and a Comparison to the Proposed Monitoring Program

Basic Monitoring Package	Enhanced Monitoring Package	San Joaquin Valley Sandstone Test
Pre-Operational Monitoring		
Well logs Wellhead pressure Formation pressure Injection and production rate testing Seismic survey Atmospheric CO_2 monitoring	Well logs Wellhead pressure Formation pressure Injection and production rate testing Seismic survey Gravity survey Electromagnetic survey Atmospheric CO_2 monitoring CO_2 flux monitoring Pressure and water quality above the storage formation	Well logs Wellhead pressure Formation pressure Injection rate testing Seismic survey (VSP) Atmospheric CO_2 monitoring CO_2 flux monitoring Pressure and water quality above the storage formation Microseismic monitoring
Operational Monitoring		
Wellhead pressure Injection and production rates Wellhead atmospheric CO_2 monitoring Microseismicity Seismic surveys	Well logs Wellhead pressure Injection and production rates Wellhead atmospheric CO_2 monitoring Microseismicity Seismic survey Gravity survey Electromagnetic survey Continuous CO_2 flux monitoring Pressure and water quality above the storage formation	Well logs Wellhead pressure Formation pressure Annulus pressure Injection rate Seismic survey (VSP and cross well) Atmospheric CO_2 monitoring CO_2 and O_2 flux monitoring Pressure and water quality above the storage formation Microseismic monitoring Active source thermal logging
Closure Monitoring		
Seismic survey	Seismic survey Gravity survey Electromagnetic survey CO_2 flux monitoring Pressure and water quality above the storage formation Wellhead pressure monitoring	Seisntic survey (VSP) CO_2 and O_2 flux monitoring Pressure and water quality above the storage formation

monitoring in the assessment well. A similar suite of logs will also be obtained once the monitoring well is drilled. Periodically repeated measurements of these logs will provide information on CO_2 saturations, brine displacement and movement, and condition of the well casing and cement.

Formation, Wellhead and Annulus Pressure: The pressure in the formation, at the wellhead inside the injection tubing, and in the annulus between the injection tubing and the well casing will be continuously monitored to ensure they remain below pre-established levels. Unanticipated changes will provide an indication that the injection equipment or well installation may not be performing as expected or is leaking. Excessively high formation pressures would indicate that the injection rate is too high and increase the potential for induced seismicity.

Injection Rate: Injection rates will be monitored to accurately account for the mass of CO_2 injected into the storage formation.

Seismic Surveys: Seismic imaging has been shown to be a reliable method for tracking the migration of CO_2 in subsurface environments (Benson et al., 2005b; Daley et al., 2007; Hovorka et al., 2006). Various geometric configurations of sources and sinks can be used to acquire images of the plume, namely, surface seismic, surface-to-borehole (e.g., VSP) and borehole-to-borehole (crosswell). Seismic imaging can also be used to detect leakage of CO_2 if secondary accumulations occur (Benson, 2007). In general, surface methods provide larger spatial coverage, but borehole methods provide higher spatial resolution. Additionally, recent developments in borehole methods provide the opportunity for real-time and continuous monitoring, which further enhances data quality and confidence (Daley et al., 2007). A VSP program is proposed that would use discrete surface source points (whose location would be determined by site access and availability along with seismic modeling of the volume to be monitored) and a permanently deployed sensor string. The sensor string should be deployed in the assessment well to allow for pre-injection monitoring. The potential for the use of crosswell imaging during the operational phase will be assessed during the characterization phase.

Atmospheric CO_2 Monitoring: CO_2 concentrations will be monitored at the wellhead for both injection and monitoring wells. The CO_2 sensors will be equipped with an automated alarm system to identify potentially unsafe conditions in the vicinity of the injection well, monitoring well and surface injection facilities.

CO_2 and O_2 Flux Monitoring: Direct measurements of CO_2 fluxes can be obtained using flux ACs and/or EC flux towers. Two approaches will be used for assessing baseline fluxes, namely flux ACs and EC towers, to characterize anthropogenic emissions in the area. One potentially promising approach is to simultaneously measure O_2 fluxes, which are anti-correlated with CO_2 fluxes from combustion sources. In this way, anthropogenic sources from combustion (e.g., automobiles and power generation) can be distinguished from releases of the injected CO_2. Verification Facility experiments beginning this summer will be incorporated into the flux monitoring program. Potential technologies include carbon isotope analysis, open-path laser measurements, and soil gas sampling.

Pressure and Water Quality above the Storage Formation: Pressure measurements provide a sensitive method to detect leakage of CO_2 or brine from the storage reservoir, particularly if there is a thin and permeable formation above the primary seal. The monitoring well will be equipped with a downhole pressure transducer to measure small changes in pressure as a means of detecting leakage. In addition, formation water samples from a monitoring zone above the storage reservoir will be sampled prior to injection to obtain baseline water quality information. Formation water samples will also be collected at the end of the injection period or periodically throughout the test period. If the pressure data suggest that leakage may be occurring, formation water samples will be collected to provide additional information to assess whether or not there is leakage.

Microseismic Monitoring: An array of geophones will be installed to detect, locate, and interpret any microseismic activity in the area of the project in the pre-operational, operational, and closure phases of the project. An estimated 120 geophones will be installed in the monitoring well, extending from a depth of 2,000 feet to a depth of about 8,200 feet. These same geophones will be used for active source seismic monitoring using the VSP method.

Active Source Thermal Logging: A new borehole-based method for monitoring fluid movement and sensing the saturation of CO_2 continuously and in real-time is being tested at the CO_2 Sink Project in Berlin, Germany. The basic concept uses fiber-optic temperature sensors to measure the rate of heat dissipation from a heater—which depends on the rate of fluid flow and the heat capacity of the formation. If the concept proves successful in the CO_2 Sink Project, the monitoring well will be equipped with an Active Source Thermal Logging system.

6.5 Williston Basin Deep Carbonate EOR Test

This project includes injection of CO_2 for sequestration and EOR in select oil fields in the Williston Basin. The primary objectives of this activity are (1) to gather characterization data that will verify the ability of the target formations to store CO_2, (2) to develop infrastructure to transport CO_2 from the source to the injection site, (3) to advance the regulatory and permitting framework in North America, (4) to provide a test bed for developing technologies related to sequestration of anthropogenic CO_2, and (5) to develop a mechanism by which carbon credits can be monetized for CO_2 sequestered in geologic formations.

Several R&D issues will be addressed by the Williston Basin test. R&D activities will be specifically focused on predictive modeling, capture, injection, and monitoring operations to demonstrate that large-scale sequestration of CO_2 in oil fields is a viable strategy for sequestering significant amounts of CO_2 within the region. The Williston Basin project will transport a minimum of 500,000 tons of CO_2 per year from an anthropogenic source (PC plant) and inject it into an oil reservoir. The power plant will be retrofitted with a system that can capture CO_2 from flue gas. The CO_2 will be compressed and transported in a supercritical state via pipeline to the injection location.

A specific oil field has not yet been chosen to be the host site for the Williston Basin large-volume CO_2 injection test. The results of regional characterization activities indicate that there are at least several unitized oil fields in the Great Plains Region that may be suitable for CO_2-based EOR operations.

The primary objective of the Williston Basin test is to verify and validate the concept of utilizing the region's large number of oil fields for large-scale injection of anthropogenic CO_2. Rigorous, robust, and cost-effective programs for baseline site characterization, risk assessment, and MVA will be conducted. The results of the study will be broadly applicable throughout the region, as there are many oil fields in the area. Oil fields are generally much better characterized than saline formations, already legally established for the purpose of safe large-scale manipulation of subsurface fluids, and offer a means to offset the considerable costs of CO_2 capture and transportation through the sale of incrementally produced oil. These attributes make oil fields the most cost-effective choices in the region when implementing large-scale CO_2 sequestration projects.

CO_2 will be obtained from a regional PC plant and transported via pipeline to the sequestration site that is anticipated to be approximately 150 to 200 miles away. Pipeline transportation and subsequent EOR require a dry gas stream containing at least 95 wt% CO_2 and low levels of any other corrosive contaminants, such as hydrogen chloride (HCl) or sulfuric acid (H_2SO_4).

This project is unique in that it will inject CO_2 recovered from the stack gas of a power plant into a deep (>10,000 feet) carbonate reservoir for simultaneous CO_2 storage and EOR. This will differ from a normal EOR project, where the objective is to maximize oil production per ton of CO_2 injected, in that the objective will be to maximize CO_2 storage.

6.5.1 Description of Target Formations

Hundreds of oil fields in the region have been thoroughly characterized since the discovery of oil in the Williston Basin in the early 1950s. Thousands of wells have been drilled into a variety of zones throughout the basin. Depths of the wells range from a few thousand feet to over 14,000 feet in the basin's center. Formation fluid production and water injection data from many of these wells provide insight into formation injectivity and permeability, as well as the integrity of overlying seals. At the oil field and reservoir level, a significant amount of historical data exists for each field, including well logging data for the reservoir and seals, fluid analyses, fluid production and water injection data, and other key reservoir dynamics data. Geophysical surveys for many areas exist, but the availability, precise nature, and applicability of the survey data with respect to the project have yet to be determined.

The Williston Basin is a relatively large, roughly circular, intracratonic basin with a thick sedimentary cover in excess of 16,000 feet. It covers several hundred thousand square miles across parts of Montana, North Dakota, South Dakota, and the Canadian provinces of Manitoba and Saskatchewan. Deposition in the Williston Basin occurred during all periods of the Phanerozoic. The stratigraphy of the area is well studied, especially in those intervals that are oil-productive. Traps in the region are generally controlled by structure or a combination of structure and stratigraphically derived porosity changes. While general information on the structural geology, lithostratigraphy, hydrostratigraphy, and petroleum geology of the Williston Basin is readily available, additional characterization data for specific candidate sinks will be necessary before their utilization as CO_2 storage sites. Detailed maps of critical elements, such as formation thickness, porosity, permeability, and water salinity, will need to be developed and the competency of regional traps will have to be determined based on further evaluations.

6.5.2 Regional Characterization

The target formation and its overlying sealing formation at any site that is considered a potential location for large-scale CO_2 injection operations must be thoroughly characterized at local, intermediate, and large scales in the early stages of the planning process. These early characterization activities are necessary to develop accurate predictions with respect to storage capacity and the ultimate fate of CO_2 within the target formation. The data from early characterization, in part, provide the baseline information necessary to design and conduct cost-effective MVA strategies. Site characterization activities will be conducted to develop predictive models that address three critical issues to determine the ultimate effectiveness of the target formation: (1) the capacity of the target formation, in this case a unitized oil-producing reservoir within an established oil field; (2) the mobility and fate of the CO_2 at near-, intermediate-, and long-term time frames; and (3) the potential for leakage of the injected CO_2 into overlying formations and/or the surface. Baseline site characterization will be accomplished using a wide variety of data. Previously conducted oil field exploration and operational activities are expected to provide significant baseline characterization data, but it is anticipated that new data will also have to be gathered to fill gaps not adequately covered by the historical oil field data.

Data obtained and compiled as part of the baseline characterization will provide the basis for a variety of modeling activities. The primary components of the modeling will be the development of (1) a geologic model that incorporates local (oil field), sub-regional (i.e., Cedar Creek, Nesson, or Billings Anticlines), and regional (Williston Basin) scale stratigraphy and architecture; (2) a hydrogeological model that operates at the local and sub-regional scales; and (3) a reservoir dynamics model for the selected reservoir. These will form the basis for developing MVA plans and conducting risk assessments of intermediate- and long-term effects of large-scale CO_2 injection.

6.5.3 Site Development

The estimated injectivity of various reservoirs suggests that two to eight vertical injection wells will be sufficient for meeting the injection target of 1 million tons of CO_2 per year. Site development may include conducting a small-scale pilot test. It is anticipated that currently existing wells in the oil field will be used as injectors, producers, and monitoring wells, but the need for drilling new wells has not been dismissed. Because the operation will include an EOR component, it is also likely that, at some point in the operation, a considerable volume of CO_2 will be produced with the oil, requiring infrastructure and equipment for capturing, recompressing, and re-injecting the produced CO_2. Thus, site design may include capture and compression equipment for CO_2 processing, pumps for CO_2 injection, and equipment for monitoring (e.g., pressure, temperature and strain gauges, and fluid sampling equipment). It is expected that both borehole and surface monitoring tools will be used along with wireline logging techniques. Use of tracers, fluid sampling, pressure, and deformation monitoring along with numerical modeling will be applied to definitively determine the area that will be affected by the injection.

6.5.4 Risk Assessment and Mitigation Strategy

Table 6-6 lists risks associated with the different stages of the CO_2 sequestration process in a Williston Basin oil field. No attempt was made to list all the consequences of the events presented (e.g., leakage can affect potable water quality, reactivation of faults can entail seismic activity, etc.). Strategies to quantify and mitigate the risks are also listed in this table.

For large-scale demonstrations, it is anticipated that a database of features, events, and processes specific to the considered environment will be created. A numerical model of the reservoir will be created and a sensitivity analysis will be performed with respect to the factors listed in the database. The analysis will allow for the quantification of the risks associated with the factors. The numerical model will be constantly updated based on the results of the monitoring program. As the model is updated, risks will be assessed to ensure safety of the operations and storage.

Table 6-6: Summary of the Potential Risks Associated with Large-Scale Injection of CO_2

Project Phase	Associated Risks	Quantification and Mitigation Strategy
Site Development	Problems with licensing and permitting	The program for site development will be reconsidered in the event of failure to obtain licenses and permits. The changes to the design can include, but are not limited to, revising the injection rates, the number of injection wells, and zonal isolation.
	Poor condition of the existing wellbores	All wells located in the vicinity of the injection site will be tested for well integrity and recompleted as necessary.
	Lower-than-expected injection rates	Basing on the results of the initial injection or a pilot test, reasonable injection rates will be determined. If actual injection rates do not meet the target, additional wells and/or pools will be added.
Operations	Significant rates of vertical CO_2 migration Activation of the preexisting faults and/or fractures Substantial damage to the formation and/or caprock Failure of the wellbores Lower-than-expected injection rates Damage to the adjacent oil fields and/or producing horizons	The monitoring program will allow for early warning regarding vertical migration, fault reactivation, and damage to the target or adjacent formations. If a warning is received, the injection program will be reconfigured.
	Failure of the wellbores	In the event of wellbore failure, the well will be recompleted or shut off.
	Lower-than-expected injection rates	Additional wells and/or pools will be included in the injection program.
Long-Term Storage	Leakage through preexisting faults or fractures	The strategy of mitigating leakage through faults will be chosen depending on measured and/or anticipated rates of leakage. It can include, but is not limited to, decreasing formation pressure and treating the fractures with cement.
	Leakage through the wellbores	All wells in the vicinity of the injection site will be periodically tested. In case of leakage, wells will be recompleted and/or plugged.

6.5.5 MVA Activities

The development and execution of effective MVA operations are a critical element in conducting large-scale injection projects. Successful MVA activities will result in data that verify that injection operations do not adversely impact human health or the environment and validate the sequestration of CO_2 for the purpose of developing and ultimately monetizing carbon credits. A broad range of technologies and approaches have been applied to CO_2 sequestration projects of various scales around the world. Early geological sequestration research and demonstration projects focused on testing a wide variety of MVA strategies. The absence of experience required early projects to gather as much data as possible using a wide variety of techniques. In particular, a desire to visually represent the plume of injected CO_2 led to a strong emphasis on the use of geophysical data, especially 3-D and 4-D seismic, to monitor the plume. While geophysical-based approaches and techniques yielded valuable results in early projects that are essential to the development of geological sequestration as a CO_2 mitigation strategy, their high costs and often limited ability to identify CO_2 in geologic settings will likely render their use the exception rather than the rule when it comes to developing MVA plans for future projects.

Where sequestration is associated with EOR operations, it is also important that MVA activities have minimal impact on commercial injection and production operations. MVA activities need to be coordinated and integrated as much as possible with ongoing and planned oil field operations. An emphasis on the collection of reservoir dynamics and monitoring well data (including the use of tracers) in conjunction with routine well operation and maintenance activities can, in some geological settings, be an appropriate and cost-effective strategy for MVA. At a minimum, the techniques listed below will be employed to monitor the effects of CO_2 injection at the site. The pre-injection state of each of these parameters will be determined by site characterization activities, either through the evaluation of historical data or focused field activities to acquire new data:

- *To monitor the CO_2 plume:*
  - Reservoir pressure monitoring
  - Wellhead and formation fluid sampling (oil, water, gas)
  - Geochemical changes identified in observation or production wells
- *To provide early warning of storage reservoir failure:*
  - Injection well and reservoir pressure monitoring
  - Pressure and geochemical monitoring of overlying formations
  - Downhole geophysical monitors (microseismic and/or tiltmeters)
- *To monitor injection well condition, flow rates, and pressures:*
  - Wellhead pressure gauges
  - Well integrity tests
  - Wellbore annulus pressure measurements
  - Surface CO_2 measured near injector points and high-risk areas
- *To monitor solubility and mineral trapping:*
  - Formation fluid sampling using wellhead or deep well concentrations of CO_2
  - Major ion chemistry and isotopes
- *To monitor for leakage into overlying formations through faults or fractures:*
  - Reservoir and overlying formation pressure monitoring
  - Monitoring for tracers (e.g., PFCs)

6.6 Impact of Secondary and Potential Additional MVA Technologies on Large-Scale Storage

Secondary and Potential Additional Technologies are commonly applied in research applications to aid in accounting for injected CO_2, providing insight into CO_2 behavior, and helping answer fundamental questions concerning the transport and fate of injected CO_2 (see page A1-2 for definitions of primary, secondary, and potential additional technologies). While Primary Technologies can validate that leakage pathways from the injection process have not been created and that CO_2 has remained sequestered underground, Secondary and Potential Additional Technologies are fully capable of confirming, as well as expanding upon, information gained from Primary Technologies by providing data over larger scales and generating details about the plume front. The case study tests described in Sections 6-1 through 6-5 are focused on employing MVA protocols consisting of Primary, Secondary, and Potential Additional Technologies for specific geological settings in order to assess CO_2 behavior under large-scale injection scenarios.

Secondary and Potential Additional monitoring techniques can have considerable advantages over existing MVA technologies by providing more insightful data over larger scales. Determining the areal extent of the plume is a critical issue when developing any MVA package. For instance, Primary Technologies, including water quality and geochemical analysis, can pinpoint elevated CO_2 levels in water/brine formations from locations in which samples are drawn. Multiple sampling locations (required by monitoring wells) would have to be generated around the site vicinity in order to confidently determine plume migration in all directions (horizontally and vertically). Several of the case studies (see Sections 6.1 to 6.5), including the Nugget Sandstone Test, Gulf Coast Strandplain Deep Sandstone Test, and San Joaquin Valley Fluvial-Braided Deep Sandstone Test, have indicated employing some form of seismic surveying (2-D, 3-D, VSP, microseismic) as a cost effective way to determine the areal extent of plume propagation over a large spatial range as opposed to drilling. In addition to determining plume migration, seismic surveying also has applications in assessing seal-formation integrity (using time-lapse images of the seal for all project phases) and adding detail to site geologic structure and stratigraphy; a task accomplished by a combination of extensive wireline logging and sample coring at several locations, as well as multiple physical testing applications (injection volume/rate, wellhead pressure, downhole pressure and temperature). Seismic surveying is one example of how the projects outlined in Sections 6.1 to 6.5 implement Secondary and Potential Additional Technologies to build upon and verify results from Primary Technologies.

Assessing potential leakage pathways is another key MVA goal in any GS project. Primary technologies can be used to identify characteristics related to potential leakage pathways, including quantifying CO_2 concentrations in fluid/brine and soil gas before, during, and after injection operations, assessing wellbore integrity during all project phases, monitoring physical and chemical properties of rocks and fluids immediately adjacent to the wellbore (via wireline logs), and alarming on elevated levels of CO_2 in the atmosphere. Storage projects, including the Gulf Coast Strandplain Deep Sandstone Test, Mt. Simon Shallow Sandstone Test, San Joaquin Valley Fluvial-Braided Deep Sandstone Test, and Williston Basin Deep Carbonate EOR Test, are coupling air, soil gas, and groundwater/brine sampling with tracers to distinguish injected CO_2 found in the air, soil, or subsurface fluid from naturally-occurring CO_2. Tracers detected above the injection zone in either the atmosphere, soil gas, or groundwater would be a direct indication of a leakage pathway somewhere in the target formation and validate results from Primary Technologies sampling efforts. Secondary and Potential Additional Technologies, such as EC, flux ACs, and the Advanced Leak Detection System (or similar), can be used in conjunction with tracers to pinpoint the location of CO_2 fluxes from the surface, enabling prompt and effective remedial action.

The level of use of Secondary and Potential Additional Technologies in the case studies goes well beyond what is anticipated for commercial GS projects. The role of Secondary and Potential Additional technologies applies mainly to research applications to gain further understanding for CO_2 accounting and to help answer fundamental questions concerning transport and fate of injected CO_2. In current GS research applications, Secondary and Potential Additional Technologies are used to help confirm, as well as expanding upon, information gained from Primary Technologies. In the case studies, research-based MVA packages that include multiple tools from Primary, Secondary, and Potential Additional Technologies categories were selected to fully understand all aspects of CO_2 behavior. MVA packages were not based solely on site geology, which will be a key factor in deciding tailored MVA protocols for commercial injections (Benson et al., 2002b).

6.7 Future Implications from Case Study MVA Packages

The research-based MVA packages of the case studies were developed prior to the site characterization and injection phases of the projects. The packages were arranged to include multiple tools that were fully capable of monitoring all aspects of CO_2 behavior associated with large-scale injection, obtain new knowledge about GS, and allow for monitoring tools to be compared and contrasted within a given project and across different geologies. Insight about the performance of MVA technologies under multiple geologic scenarios will enable future GS projects (for either commercial or research purposes) meet their monitoring needs by optimizing MVA packages that best suit both the site and regional characteristics.

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Appendix I

Comprehensive Monitoring Techniques List—Atmospheric Monitoring

Introduction

Appendix I provides descriptions of atmospheric monitoring techniques available for deployment during geologic CO_2 storage projects. The descriptions include applications, benefits, challenges, and experience relative to each technique. Monitoring tools are categorized into one of three categories, based on application, function, and stage of development:

> *Primary Technology* – A proven and mature technology or application capable of handling the minimum monitoring requirements that could meet the 95 percent and 99 percent CO_2 containment goals for CCS projects for 2008 and 2012, respectively.
>
> *Secondary Technology* – An available technology/ protocol that can aid in accounting for injected CO_2 and/or provide insight into CO_2 behavior that will help refine the use of Primary Technologies.
>
> *Potential Additional Technology* – A technology/ protocol which is research related and might answer fundamental questions concerning the behavior of CO_2 in the subsurface and which might have some benefit as a monitoring tool after testing in the field.

Atmospheric monitoring techniques can be used in identifying CO_2 concentrations above ambient background level and helping to determine locations of CO_2 leaks. CO_2 monitoring can detect dangerous concentrations of CO_2 that may be a threat to workers and others in and around the project site.

Characterization of the atmosphere is carried out during site selection, especially with respect to obtaining permits. It is usually required to quantify the impact of surface activities, such as processing plants, on criterion pollutants. In addition, it is desirable to begin an air monitoring program as soon as possible to obtain a baseline that extends over all seasons and includes the range of perturbations (weather, rainfall, agricultural and industrial activities, etc.). Local atmospheric modeling can help optimize an atmospheric monitoring plan. Documentation of local wind speed, temperature, barometric pressure, and rainfall is needed to provide context for any atmospheric monitoring. These measurements are commonly included within more sophisticated tools.

Benefits of atmospheric methods: Direct measurement of the atmosphere is important in answering the key questions: is sequestration working to prevent the return of CO_2 to the atmosphere and are conditions safe for humans? Compared to shallow subsurface and deep subsurface monitoring, atmospheric monitoring is lower cost, because of easy access on the surface, although for several tools towers above ground surface are needed to get a good signal. The atmosphere is the best mixed medium for detection and can, therefore, be used as an integrator to document that there is no measurable leakage over large areas. Measurements can be instantaneous, which would allow rapid response should a large leak be detected. Atmospheric measurements can provide high frequency data, as well as multiple parameters (e.g., wind speed and direction, moisture, isotopes, relative ratios of different gases, etc.) that may be needed to understand a complex system.

Challenges: Because the atmosphere is well mixed, the signal may be diluted at areas away from the point of interest. In addition, numerous sources of CO_2 emissions, such as soil and vegetation, combustion and other industrial processes, and surface handling of CO_2, can create a highly variable, "noisy" baseline, so that only very large leaks may be detectable, or CO_2 detection at many points may indicate changes other than leakage from geologic storage. Measurement of leakage at the surface is retarded relative to leakage out of the injection zone. Retarded detection would reduce risk management and remediation options and, possibly, the success of the project. A retarded response would also mean that an extended monitoring period would be required to document integrity of the system, if atmospheric methods were relied on to meet this need. Because a well selected site should have no leakage to the atmosphere, significant cost and effort is required to obtain a null result for a CO_2 storage project (i.e., many samples will be required).

The following atmospheric monitoring techniques are discussed in this appendix:

1. CO_2 Detectors
2. Eddy Covariance
3. Advanced Leak Detection System
4. Laser Systems and Light Detection and Ranging (LIDAR)
5. Tracers (Isotopes)

1. CO_2 Detectors (Secondary)

- *Description:* CO_2 detectors rely on infrared detection principles and are small and portable. To ensure that they are correctly calibrated, periodic sampling for laboratory analysis using gas sampling bags and gas chromatography for measuring CO_2 concentrations relative to other gasses can be employed (Benson et al., 2005).
- *Applications:* This type of monitoring is mostly used for assuring worker safety or for initial assessment. For abandoned or orphaned wells, infrared CO_2 detectors can be deployed in many modes. For example, an individual could visit a wellhead on an occasional basis to check for leaks. CO_2 detectors serve as site worker safety devices by triggering automated alarm systems to identify high CO_2 levels.
- *Benefits:* Simple, readily available technology. Can often simultaneously monitor for other relevant gases, such as hydrogen sulfide (H_2S) and combustibles. Alarms available.
- *Challenges:* Devices used only for qualitative CO_2 detection. Does not provide quantitative information on the rate or volume of the leak.
- *Geologic Storage Experience:* Air monitoring was used for worker safety at the Frio test and is planned for other projects.

2. Eddy Covariance (Potential)

- *Description:* Atmospheric flux measurement technique to measure atmospheric CO_2 concentrations at a height above the ground surface. These systems can detect CO_2 fluxes over large areas in real-time, along with micrometerological variables, such as wind velocity, relative humidity, and temperature (Anderson and Farrar, 2001; Baldocchi et al., 1996). Integration of these measurements allows derivation of the net CO_2 flux over the upward footprint (either m^2 or km^2 scale, depending on tower height).
- *Application:* Used to detect CO_2 flux over a large area in real-time.
- *Benefits:* Technology can provide accurate data under continuous operation, if conditions are favorable.
- *Challenges:* Requires specialized equipment and data processing. Requires a significant number of instruments capable of measuring vertical wind speed and water vapor mixing heat transfer. Open-path systems tend to underestimate covariance due to sensor placement. Precipitation, winds from unfavorable directions, or extremely calm conditions can cause erratic, nonsensical results (Baker, 2008). CO_2 from many sources (vegetation, soil gas, industry, compressors, pipelines, etc.) may mask leakage signal because of the magnitude and temporal variability of these sources.
- *Geologic Storage Experience:* ZERT has documented the performance in simulated geologic storage "leak" settings. Otway is testing this and other atmospheric approaches (see http://www.cmar.csiro.au/ozflux/monitoringsites/otway/purpose.html).

3. Advanced Leak Detection System (Potential)

- *Description:* An advanced leak detection system that can generate geo-referenced CO_2 concentration data along a path or route. The system incorporates a high sensitivity three-gas detector (CH_4, total hydrocarbons, and CO_2) with a Global Positioning System (GPS) with real-time mapping.
- *Application:* This system is commonly applied to pipeline monitoring via a ground or airborne vehicle, transmission and liquid line monitoring, and landfill liner integrity monitoring.
- *Benefits:* Detection of total gas composition can be used to separate leakage signal from processes that produce CO_2. CO_2 leakage by itself would displace all other gasses equally, whereas in-situ generation of CO_2 by biologic action or combustion decreases oxygen.
- *Challenges:* Increased time and labor to sample and reduce data; less immediate response.

4. Laser Systems and Light Detection and Ranging (LIDAR) (Potential)

- *Description:* LIDAR is an optical remote sensing technology that measures properties of scattered light to find the range (or other information) of a distant target. Laser pulses are used to determine the distance to an object or surface. Similar to radar technology, which uses radio waves instead of light, the distance to an object is determined by measuring the time delay between transmission of a pulse and detection of the reflected signal. An open-path device uses a laser to shine a beam (with a wavelength that CO_2 absorbs) over many meters. The attenuated beam reflects from a mirror and returns to the instrument for determination of the CO_2 concentration. One instrument can sample a large area, if the beam can reflect from more than one mirror.
- *Application:* LIDAR is highly sensitive to aerosols and cloud particles and has many applications in atmospheric research and meteorology (Cracknell, 2007). Differential Absorption LIDAR (DIAL) is typically applied to detecting atmospheric concentrations of CO_2 above storage sites and in the vicinity of pipelines in R&D sequestration projects.
- *Benefits:* Non-intrusive method to collect data in areas of limited access or containing potential physical or chemical hazards. LIDAR data collection is not limited to daylight hours. Large area data collection over short time. LIDAR can penetrate vegetative canopy. Lasers have the ability to measure CO_2 concentrations over large areas so that any leaks can be quickly detected and remediation measures undertaken.
- *Challenges:* Large data sets are difficult to store, manipulate, and utilize. LIDAR data not readily supported by mainstream software. Optimal weather conditions needed for operation. Water features absorb or scatter laser pulses.
- *Geologic Storage Experience:* Lasers tested at ZERT.

5. Tracers (Isotopes) (Potential)

- *Description:* Tracers are unique or highly indicative chemical species that can be used to "fingerprint" the CO_2 of interest and distinguish it from other sources. In addition, tracers can be used to understand the flow path of fluids, for example in a remediation situation.

  The occurrence of artificial tracers, for example perfluorocarbon tracers (PFTs) or SF_6 in natural systems is so small that detection and attribution may be done at parts-per-billion detection. Noble gases occur naturally in CO_2; they can also be introduced to "spike" the CO_2 to make it more distinctive for advanced studies, and they are "conservative," meaning that they are less reactive and less soluble than CO_2. The isotopic composition of the carbon and oxygen in the injected CO_2 (if different from the ambient CO_2), as well as minor entrained impurities, can be used to distinguish injected CO_2 from ambient CO_2. These constituents, however, are not conservative; as CO_2 moves though rock/fluid/soil/ecosystem, the ratios of isotopes and entrained constituents will be modified, giving a record of the reaction pathway.
- *Application:* Chemical tracers, both natural and introduced, can be used for in situ subsurface characterization, model calibration, and leak detection. Naturally occurring chemical constituents, such as stable isotopes of C, H, O, or sulfur (S), can be used to assess fluid origin, detect CO_2 migration or leakage into the atmosphere and assess interaction with host rocks along flow paths (Cole et al., 2004). Researchers at LBNL have recommended using naturally stable isotopes for use in concert with multiple injected PFTs as a method to interpret subsurface CO_2 transport processes and monitor possible CO_2 leakage pathways (GEO-SEQ, 2004). A variety of sampling and analytical approaches are available, including direct extraction from flux chambers, simple or complex soil gas wells, and sorbent approaches. Analysis can be done in the laboratory or via various types of field instruments.
- *Benefits:* Proven technique in other applications that allows for differentiation between injected CO_2 and naturally occurring CO_2. In advanced applications (for assessing a potential leak), tracers can provide essential information about flow path and processes that could be used to design effective remediation.
- *Challenges:* Many introduced tracers (PFTs, SF_6) are benign in water and ecosystems but are powerful greenhouse gasses. They, therefore, need to be used conservatively. Because of low detection limits, contamination is a serious risk; it is important to use best practices to inject tracers (separate handling for injection and detection). More information is needed

about interaction of introduced tracers with water, rocks, soil, and organics. Natural tracers are known to have complex reactions with rock, water, and soil, requiring a fairly sophisticated approach to produce a correct interpretation.

- *Geologic Storage Experience:* PFT soil detection with capillary adsorbent tubes (CATs), analyzed by BNL, conducted by NETL at West Pearl Queen, New Mexico, (Wells et al., 2007) and Frio.

APPENDIX I REFERENCES

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Appendix II

Comprehensive Monitoring Techniques List—Near-Surface

Introduction

Appendix II provides descriptions of near-surface monitoring techniques available for deployment during geologic CO_2 storage projects. The descriptions include applications, benefits, challenges, and experience relative to each technique. Monitoring tools are categorized into one of three categories, based on application, function, and stage of development:

> *Primary Technology* – A proven and mature technology or application capable of handling the minimum monitoring requirements that could meet the 95 percent and 99 percent CO_2 containment goals for CCS projects for 2008 and 2012, respectively.
>
> *Secondary Technology* – An available technology/protocol that can aid in accounting for injected CO_2 and/or provide insight into CO_2 behavior that will help refine the use of Primary Technologies.
>
> *Potential Additional Technology* – A technology/protocol which is research related and might answer fundamental questions concerning the behavior of CO_2 in the subsurface and which might have some benefit as a monitoring tool after testing in the field.

Near-surface techniques play a vital role in the preservation of shallow groundwater sources and supply critical information on any major vertical migration of injected CO_2. Characterization of the near surface environment begins during site selection with assessing any required environmental and culture features, for example wetlands, floodplains, antiquities, significant habitat, groundwater, soil and other resources, land use, human populations, and infrastructure. The exact elements will be specific to the local requirements. For development of an effective near surface monitoring plan, detailed characterization of the static and changing conditions in the system is needed. This includes aspects, such as groundwater potentiometric surface and seasonal variability, moisture and temperature of the vadose zone, the effects of cropping, irrigation, and changing land use. Many tools are available from disciplines, such as groundwater management, site remediation, and agriculture. A few examples include cores for soil properties, soil moisture and soil gas wells, and surface data collection devices, groundwater wells with transducers for water level measurement, and surface surveys of soil and vegetation.

Benefits of near-surface methods: The surface and shallow subsurface are more accessible at lower cost than the deep subsurface. Residence time of CO_2 is longer in the shallow subsurface than in the atmosphere above the leak, increasing the probability of detecting the leak. Some risk factors, for example a confined space (basement) risk, are probably mostly tied to a soil gas source of CO_2. In addition, the near surface contains a major resource protected by regulation, USDW, and monitoring of this resource may increase public confidence and, by early detection, reduce any liability from leakage.

Challenges of near-surface methods: As with the atmosphere, there are numerous sources of near surface CO_2 emissions, such as soil microbes and vegetation; in-situ remediation of oil spills produces large amounts of CO_2. The soil gas system is complicated by factors, such as moisture, temperature, nutrients, and barometric pressure that vary daily, seasonally, and complexly. Measurements of leakage from soil gas may be very close to the leakage point (e.g., results of ZERT), although it is possible that buildup in the vadose zone would result in leakage at a topographic low point distant from the leakage point. Ground water systems may be dynamic, responding to recharge and discharge. Like the atmosphere, with groundwater a leakage signal may be diluted or attenuated by rock-fluid interaction (buffering) away from the point of leakage. Like the atmosphere, measurement of leakage at the near surface is retarded relative to leakage out of the injection zone. Retarded detection reduces risk management and remediation options and possibly the success of the project. A retarded response would also mean that an extended monitoring period would be required to document integrity of the system if near surface methods were relied on to meet this need. A well selected site should have no leakage to surface; therefore, a significant cost and effort is required to obtain a null result for a CO_2 storage project (many observations will be required).

The following near-surface monitoring techniques are discussed in this appendix:

1. Ecosystem Stress Monitoring
2. Tracers
3. Groundwater Monitoring
4. Thermal Hyperspectral Imaging
5. Synthetic Aperature Radar (SAR and InSAR)
6. CIR Transparency Films
7. Tiltmeter
8. Flux Accumulation Chamber
9. Induced Polarization (IP)
10. Spontaneous (Self) Potential
11. Soil and Vadose Zone Gas Monitoring
12. Shallow 2-D Seismic

1. Ecosystem Stress Monitoring (Potential)

- *Description:* Color infrared orthoimagery, satellite imagery, and aerial photography can be used to assess ecosystem stress as an indicator of CO_2 or brine leakage.
- *Application:* CO_2 or brine leaks from underground storage sites may have significant impacts on local ecosystems in the shallow subsurface, the sea floor, and within the water column that could provide useful indicators. Detection techniques require initial surveys to establish baseline conditions above storage sites. Confidence in leakage detection will require improved understanding of how plant populations change in composition, quantity, and health as conditions change.
- *Benefits:* Direct monitoring of ecosystem health can provide confidence that the storage system is not causing damage, reduce risk in case of leakage, and guard against challenges in cases where observed changes are not the result of CO_2 injection.
- *Challenges:* Ecosystem sensitively to leakage is variable with species and setting, which may cause methods to be insensitive (false negatives). Many other factors leading to ecosystem stress lead to abundant changes that must be followed up using other techniques (false positives). Absence of data on the quantitative effects on marine and terrestrial ecosystems of excess CO_2 from leaking storage sites (West et al., 2005).
- *Geologic Storage Experience:* ZERT has nice results. British Geological Survey (BGS) did a test in an area of natural leakage in Italy (see CO2GeoNet for results [http://www.co2geonet.com]). Volcanogenic sources with high fluxes of CO_2 at Mammoth Mountain, CA, studied by USGS, provide a case study of impact of leakage on tree kills.

2. Tracers (Potential)

- *Description:* Tracers are unique or highly indicative chemical species that can be used to delineate the flow-path of fluids in the subsurface. For CO_2 sequestration projects (Nimz and Hudson, 2005), tracers have included noble gases and PFTs. The occurrence of these chemicals in natural systems is so low that detection and attribution may be done at parts-per-billion detection. In some cases, the isotopic composition of the CO_2 is readily identifiable, and has been used as a tracer.
- *Application:* Chemical tracers, both natural and introduced, can be used for in situ subsurface characterization, model calibration, and leak detection. Naturally occurring chemical constituents, such as stable isotopes of O, C, H, N, and S; noble gases Kr, Ne, argon (Ar), He, xenon (Xe) and their isotopes; and radioactive isotopes (e.g., ^{3}H, ^{14}C, ^{36}Cl, ^{125}I, ^{129}I, ^{131}I) can be used to assess fluid origin, detect CO_2 migration or leakage into the atmosphere and assess interaction with host rocks along flow paths (Cole et al., 2004). Researchers at LBNL have recommended using naturally stable isotopes for use in concert with multiple injected PFTs as a method to interpret subsurface CO_2 transport processes and monitor possible CO_2 leakage pathways (GEO-SEQ, 2004). Research funded by DOE's Core R&D program has led to the development of an in situ stable isotope analysis system as part of a focus at developing novel monitoring tools for geologic sequestration. Phase-partitioning tracers could be used to determine the amount of immobile phases (such as the residual oil in a petroleum reservoir). Preliminary tests have been carried out at the Frio project in Texas to test the applicability of phase-partitioning tracers to estimate the amount of residual gas trapping that has taken place. Residual gas trapping is an important parameter for estimating long-term storage integrity.
- *Benefits:* Proven technique in other applications that allows for differentiation between injected CO_2 and naturally occurring CO_2.
- *Challenges:* While it is comparatively straightforward to measure the parameters listed

above, interpreting these measurements to infer information about geochemical reactions is much more challenging. Utilization of tracers requires the availability of a number of boreholes in and around the injection plume. The use of tracers for CO_2 geologic storage has yet to be demonstrated.

- *Geologic Storage Experience:* NETL participated in the ZERT field experiments, which injected small amounts of tracer-spiked CO_2 just below the soil from vertical and horizontal wells. Surface flux and tracer mappings were in agreement and provided complementary information for modeling CO_2 movement near the surface. Otway employed noble gas tracers.

3. Groundwater Monitoring (Primary)

- *Description:* Impacts on groundwater can result from migration of CO_2 or brine into USDWs. Groundwater monitoring can be used to assess changes though time and across an area with indicators, such as pH, specific conductance, alkalinity, major and trace chemical constituents, dissolved gases, stable isotopes, radio-isotopes (^{14}C), and redox potential, to understand the location and consequences of CO_2 migration. Changes in the chemical composition of groundwater could be used to detect leakage or the risk of changes in water quality. Changes in pH, alkalinity, redox potential, specific conductance, stable isotopes, and gases are used to elucidate the impact on drinking water of saline water or CO_2 migration.
- *Application:* A successful monitoring program should include both pre- and post-injection sampling and assessment of baseline water chemistry and mineralogy. Well spacing needs to consider sensitivity and attenuation, risk factors, groundwater flow direction and rate, and account for non-geologic storage changes.
- *Benefits:* Groundwater is an integrating horizon that covers all, or much of, many sites; it flows and, therefore, an up-gradient/down-gradient sample point array could be effective in determining that there is no change resulting from geologic storage of CO_2. Direct monitoring of a protected resource provides public confidence.
- *Challenges:* Need wells and natural sample points, as there may be water resources at different depths. Some parameters could be collected automatically using probes on data loggers or with uplinks to monitoring stations. However, some of the most useful require sample collection and laboratory analysis. Many factors besides geologic storage could cause change and, therefore, enough sample points are needed to assess the reasons for the observed change, such as land use changes. Groundwater systems may be relatively insensitive to perturbation by introduction of CO_2 because of buffering.
- *Geologic Storage Experience:* Small test at Frio, Otway, and SWP Phase II at SACROC. Each of these tests has found a fairly complex and dynamic environment. Testing planned at SECARB Phase III test at Cranfield, Illinois.

4. Thermal Hyperspectral Imaging (Potential)

- *Description:* Hyperspectral imaging collects and processes information from across the electromagnetic spectrum. Hyperspectral sensors collect information as a set of images. Each image represents a range of the electromagnetic spectrum, also known as a spectral band. These images are then combined and form a three dimensional hyperspectral cube for processing and analysis. Sensors may be airborne, satellite mounted, or hand held.
- *Application:* Like CIR, hyperspectral imaging is an excellent tool in assessing vegetative integrity around an injection site. DOE's Core R&D program investigated a ground-surface controlled leak experiment releasing CO_2 and CH_4 that was conducted at the Naval Petroleum Reserve Site #3 in Wyoming in 2006. Aerial hyperspectral imagery based on MASTER technology was acquired, and analyses of these data demonstrated that MASTER could identify CO_2 and CH_4 surface seeps at high concentrations.
- *Benefits:* Since an entire spectrum is acquired at each point, the operator needs no prior knowledge of the sample, and post-processing allows all available information from the dataset to be mined. Data can be acquired over a relatively large area quickly and efficiently. Airborne or satellite deployment can image the whole area, including areas that are poorly accessible on the ground.

- *Challenges:* Fast computers, sensitive detectors, and large data storage capacities are needed.
- *Geologic Storage Experience:* Teapot test.

5. Synthetic Aperture Radar (SAR and InSAR) (Potential)

- *Description:* SAR (InSAR—Interferometric Synthetic Aperture Radar) is a satellite-based technology in which radar waves are sent to the ground. The measured reflection of those waves provides high-precision information on the position of the ground surface (Gabriel et al., 1989). Several commercial SAR satellites are currently available and applicable to monitoring large sequestration projects, and new, more capable systems are in the pipeline. Most commercial systems provide 100 kilometer by 100 kilometer scenes, a sufficiently broad area for even the largest sequestration project. Provided the repeat orbit of one scene is close enough to that of a later pass over the same specific scene, the two scenes can be interferometrically processed to produce an image of the vertical surface deformation of the earth that has occurred between the time the first scene was collected and the time the second scene was collected.
- *Application:* This technique measures the surface effect of subsurface phenomena. The surface deformation maps can be used to monitor groundwater and oil reservoir drawdown over time, understand earthquakes, and explore for geothermal resources. InSAR, if applicable at the site of interest, will be one of the essential methods for monitoring a large CO_2 injection effort by providing large scale snapshots of changes that the injection and movement of the subsurface CO_2 may reveal via surface deformation. InSAR methods work best in environments with minimal topography, minimal vegetation, and minimal land use. Adaptive methods, such as reflectors, can be deployed where these conditions are not met. A related technique is direct measurement of changes in elevation though mapping with LIDAR.
- *Benefits:* Measurement of the surface response to elevated pressure though time lapse. Satellite based, covers very large areas, including inaccessible areas.
- *Challenges:* The area of elevated pressure is mapped, not the plume of injected CO_2. Numerous assumptions required to translate surface response to subsurface. Steep terrain is difficult to correct for in the processing step and gives rise to soil slippage and rock fall that can de-correlate the image. Vegetation can upset the radar reflection point for many commercial systems and produce a de-correlated image.

6. Color Infrared Transparency Film (Potential)

- *Description:* This technology utilizes three sensitized film layers that reproduce infrared as red, red as green, and green as blue, due to the way the dyes are coupled to these layers. All three layers are sensitive to blue so the film must be used with a minus blue (i.e., yellow) filter. Vegetative health can be determined from the relative strengths of green and infrared light reflected; this shows in color infrared as a shift from red (healthy) towards magenta (unhealthy).
- *Application:* CIR aerial photos of specific project sites can be taken from an aircraft or by satellite to determine vegetative health in the vicinity of the project site as an indicator of a possible CO_2 leakage pathway (Crum, 2006).
- *Benefits:* A combination of wavelengths provides a better understanding of happenings on the Earth's surface. Good indicator of vegetative health.
- *Challenges:* The presence of water interferes with the quality of the image due to absorption of near-infrared wavelengths (appears black on the image). Must have a means to obtain aerial CIR images (aircraft, satellite, etc.).

7. Tiltmeter (Potential)

- *Description:* A tiltmeter is an instrument designed to measure very small changes from the horizontal, either on the surface or at depth. In essence, it works like a carpenter's level, except that it can detect and quantify extremely small deviations from horizontal.
- *Application:* These tools are regularly used to monitor oil field operations, including water and CO_2 flooding and hydrofracturing. Several commercial companies offer this technology, and tiltmeter arrays can be installed either at the earth's surface or within subsurface wells. Measurements are typically collected remotely and sent for interpretation via radio or satellite telemetry. This approach is useful in places where long-time series can be collected to

remove noise. Ideally, a combination of surface and subsurface tools is deployed, but that is a function of well and surface availability. Tiltmeters can be strategically placed around the site to determine surface deformation caused by interaction of the CO_2, brine, and rock. Typically, deformation is less than a few centimeters, which can be measured with existing tiltmeters (NETL, 2008). CONSOL Energy Inc. is employing surface tiltmeters to measure reservoir deflection and to track plume movement in a DOE funded project that demonstrates a novel drilling and production process that reduces potential methane emissions from coal mining, produces usable methane (natural gas), and creates a sequestration sink for CO_2 in unmineable coal seams.

- *Benefits:* A technique which is sensitive to the pressure in the injection zone is useful, as elevated pressure is itself a risk factor.
- *Challenges:* An array of many tiltmeters is required (often far from the injection site) to measured the area of deformation. Does not identify the CO_2 plume.
- *Geologic Storage Experience:* CONSOL Energy, Inc. is employing surface tiltmeters to measure reservoir deflection and track plume movement in a DOE funded project that demonstrates a novel drilling and production process that reduces potential methane emissions from coal mining, produces usable methane (natural gas), and creates a sequestration sink for CO_2 in unmineable coal seams.

8. Flux Accumulation Chambers (Secondary)

- *Description:* An accumulation chamber with an open bottom (cm^2 scale) is placed either directly on the soil surface or on a collar installed on the ground surface. Air contained in the chamber is circulated through an IRGA, and the rate of change in CO_2 concentration in the chamber is used to derive the flux of CO_2 across the ground surface at the point of measurement (Norman et al., 1992). Advanced techniques include using other trace gases, such as radon, as proxies for determining and differentiating gas fluxes from depth (Baubron, 2005).
- *Application:* These chambers quantify the CO_2 flux from the soil at a small, predetermined area.
- *Benefits:* Technology can quickly and effectively determine CO_2 fluxes from the soil at a predetermined spot. Allows collection of high quality gas sample, from which naturally occurring tracers, such as isotopes or noble gasses, or introduced tracers can be detected. Flux is assumed to be more closely related to leakage rate than is concentration.
- *Challenges:* Monitoring a large area requires many installations. Soil gas flux has strong seasonal and other temporal variability that has to be controlled for by the method to provide leakage estimates. Soil flux is not effective if water table is high or soil is wet or frozen.
- *Geologic Storage Experience:* Flux accumulation chambers have been used at ZERT, Rangeley, Weyburn, and Frio (not successful) and are planned for several RCSP projects – SECARB Black Warrior coal, others.

9. Induced Polarization (IP) (Potential)

- *Description:* IP is comparable to electrical resistivity tomography techniques due to electrical currents being induced in the subsurface via two electrodes, with voltage being observed through two other electrodes. IP is observed when a steady current through two electrodes in the Earth is terminated; the voltage does not instantly return to zero, but rather decays slowly, indicating that charge has been stored in the rocks. This charge mainly accumulates at interfaces between clay minerals and is responsible for the IP effect. In particular, time domain IP methods measure the voltage decay or chargeability over a given time interval once the induced voltage is removed. The integrated voltage is used as the measurement. Frequency domain-based IP approaches use alternating currents to generate electric charges in the subsurface, and the apparent resistivity is measured at different alternating current frequencies (Keary et al., 2001).
- *Application:* Geophysical imaging technology is used to detect metallic materials in subsurface strata, particularly ores.
- *Benefits:* Detecting metallic materials in the subsurface with fair ability to distinguish between different types of mineralization.
- *Challenges:* Difficult to accurately depict non-metallic based materials in the subsurface.
- *Geologic Storage Experience:* For planned use of IP by the RCSPs, see Table 5-1.

10. Spontaneous (Self) Potential (Potential)

- *Description:* Method based on the surface measurement of natural potential differences resulting from electrochemical reactions in the subsurface. SP anomalies normally have an amplitude of several hundred millivolts with respect to barren ground. Field equipment consists of a pair of electrodes connected by a high-impedance millivoltmeter. The electrodes must be non-polarizing (normally by immersion in a saturated solution of its own salt, e.g. copper in copper sulfate), as simple metal spikes would generate their own SP effects. The salt is contained in a porous pot which allows slow leakage of the solution into the ground.
- *Application:* Interpretation of SP anomalies is similar to magnetic interpretation, because dipole fields are involved in both cases. All interpretation is assumed to be qualitative at best. The anomaly minimum is assumed to occur directly over the anomalous body. The anomaly half-width provides a rough estimate of depth, and the symmetry or asymmetry provides information about the attitude of the body, the steep slope, and positive tail of the anomaly lying on the downdip side (Kearey et al., 1991).
- *Benefits:* Rapid and cheap method requiring only simple field equipment. Useful in rapid ground reconnaissance for base metal deposits when used in tandem with EM and geochemical techniques.
- *Challenges:* Provides little information in subsurface exploration efforts. Data should be considered only for qualitative purposes. Penetration is limited to about 30 meters. Clay covering may mask SP anomaly of formations below.

11. Soil and Vadose Zone Gas Monitoring (Secondary)

- *Description:* Bulk chemical composition of gases collected at soil and subsoil depth can be used to quantify CO_2 concentration profiles (by depth) and asses whether CO_2 originates from natural or nonbiologic-respiration sources (e.g., fossil fuel combustion). Numerical simulation studies of leakage and seepage demonstrate that CO_2 concentrations can attain high levels in the shallow subsurface even for relatively moderate CO_2 leakage fluxes (Oldenburg and Unger, 2003). Soil pore gas concentrations and isotropic composition can be measured using a variety of techniques, including drive points (geoprobes), IRGAs, gas chromatography, and mass spectrometry. American Standard Test Method (ASTM) D5314-92 provides the standard protocol for monitoring soil gas in the vadose zone.
- *Application:* The soil gas technique provides accurate measurements of CO_2 concentration at a particular location, but depends on the sampling grid. The spatial resolution must be considered. Although a higher sampling density is achievable, it will increase the expense and decrease the speed of ground coverage.
- *Benefits:* Can collect diverse information needed to interpret signal (e.g., gas ratios, isotopes, moisture).
- *Challenges:* To be valid, soil gas sample points need to be spaced so as to detect leak points, which natural analogs suggest could be small and localized. Well construction must complete wells in zone of interest, avoiding atmospheric leakage.
- *Geologic Storage Experience:* See Atmospheric Monitoring (Appendix I).

12. Shallow 2-D Seismic (Secondary)

- *Description:* Method of exploration geophysics that implements the principles of seismology that has been applied to shallow surface imaging from reflected seismic waves. The technique is based on determination of the time interval elapsed between the initiation of the seismic wave and the arrival of reflected or refracted impulses at one or more seismic detectors. The method requires a controlled and repeatable seismic energy source. By documenting the time it takes for a reflection to arrive at a receiver, it is possible to estimate the depth of the feature that generated the reflection. In this way, reflection seismology is similar to sonar and echolocation. The source–receiver array can be along a line (2-D survey) or in a pattern across the land surface (3-D survey).
- *Application:* Seismic reflection technology has been applied to characterizing the shallow geology at locations that are environmentally contaminated; in detecting shallow subsurface voids that might be related to sinkholes, tunnels, or construction; in mapping faults or bedrock surfaces; and in other situations. Shallow seismic might be deployed in time-lapse mode to look for changes from the baseline, or post-injection when a leak is suspected to try to image a concentration of trapped gas phase CO_2 by mapping a bright spot.

- *Benefits:* Technology that can provide high-resolution images of the subsurface for monitoring design. Should CO_2 leak and accumulate at shallow depth, the low density of the gas phase would be expected to produce a strong area of slow velocity, readily mapped as change from baseline, or even in a single survey, as a bright spot.
- *Challenges:* Seismic techniques respond to a significant change in velocity of sound through the rock/fluid system so that CO_2 dissolved in ground water would not be likely to produce a measurable signal. Thin or low-saturation gas phase CO_2 (near wells or faults) may also be below the resolution and, therefore, undetectable. Resolution of sound waves and depth of penetration are inversely related; cost of surveys and processing and source and receiver spacing are also related, requiring careful design. Static errors caused by changes in shot points or in near surface conditions can reduce detection; they may also add noise. Resulting errors in processing may create a signal where no change in fluids occurred (false positive). It is not possible to quantify CO_2 volume using seismic, as thickness and saturation are both difficult to quantify. Mass-balance and dissolution/mineral trapping are difficult to monitor. Out of plane migration is not quantified.
- *Geologic Storage Experience:* Most seismic surveys conducted for geologic storage have been designed for deep injection zone targets; however, success with detection at Weyburn, Sleipner, and Frio (borehole) add confidence that, if seismic surveys were undertaken for leak detection, they could be successful, given favorable concentration and thickness.

APPENDIX II REFERENCES

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Appendix III

Comprehensive Monitoring Techniques List—Subsurface Monitoring

Introduction

Appendix III provides descriptions of subsurface monitoring techniques available for deployment during geologic CO_2 storage projects. The descriptions include applications, benefits, challenges, and experience relative to each technique. Monitoring tools are categorized into one of three categories, based on application, function, and stage of development:

> *Primary Technology* – A proven and mature technology or application capable of handling the minimum monitoring requirements that could meet the 95 percent and 99 percent CO_2 containment goals for CCS projects for 2008 and 2012, respectively.
>
> *Secondary Technology* – An available technology/ protocol that can aid in accounting for injected CO_2 and/or provide insight into CO_2 behavior that will help refine the use of Primary Technologies.
>
> *Potential Additional Technology* – A technology/ protocol which is research related and might answer fundamental questions concerning the behavior of CO_2 in the subsurface and which might have some benefit as a monitoring tool after testing in the field.

Subsurface monitoring techniques play a vital role in identifying CO_2 plume location, pressure propagation, and reservoir and seal integrity. MVA techniques can detect CO_2 and compare observations with the predicted fate and transport results from modeling efforts. Characterization and modeling are the first lines of defense to assure that the injection zone is behaving as predicted; this involves tools, such as surface and well-bore seismic methods, coring and core analysis, open hole wireline logging, single and multiple well hydrologic testing, step-rate pressure testing (to reveal the maximum allowable pressure prior to caprock fracturing), and rock-fluid-engineered system geochemical and geomechanical compatibility assessments. Many techniques can be imported from oil and gas exploration and reservoir management disciplines, as well as from Class I and Class II UIC experience. Laboratory analyses are important to constrain data collected in the field; these data can range from mineralogical descriptions of cores via thick section, scanning electron microscope, x-ray diffraction end-point or a whole range of hysteretic curves for fluids of interest, batch or flow-though rock-water-fluid interactions, tracer behavior, and laboratory assessment of relevant acoustic or EM energy into the rock-fluid system. A central goal of characterization is to develop accurate input data to represent the earth system in a set of numerical models that will predict the performance of the injection zone as fluids are introduced.

A variety of techniques are also available to assess the condition of the well and ensure that the well itself does not provide a leakage pathway for CO_2 migration. Several logs are routinely used for this purpose, including temperature, noise, casing integrity, and radioactive tracer logs (Benson et al., 2002). It is worth noting that the resolution of cement bond and well integrity logs may not be sufficient to detect very small rates of seepage through microcracks (Benson and Meyer, 2002).

Benefits of subsurface methods: The location of the CO_2 and the region of elevated pressure can be more easily predicted than any potential leakage. The volume, thickness, and saturation will also be high relative to any leak scenario. Substitution of supercritical CO_2 (nonconductive, density of 0.6 g/cm^3) for brine (conductive, density >1 g/cm^3) results in a relatively strong geochemical, geophysical, and compositional contrast, and many techniques can be used to image it. Tracking the plume and area of elevated pressure (AOR) can be done with many techniques to provide public confidence.

Challenges of subsurface methods: The depth of the injection zone (desirable for isolation and separation from USDW) makes direct access to the injection zone through deep wells costly and limits the types and resolution of geophysics. No techniques are available to measure the CO_2 in situ with precision; it is, therefore, not possible to directly quantify CO_2 in the injection zone and determine that none has leaked. It is necessary to use indirect or inferential methods to document that the injection is performing as expected and that CO_2 and brine are not escaping the injection zone in unacceptable directions and at unacceptable rates.

The following subsurface monitoring techniques are discussed in this appendix:

1. Multi-component 3-D Surface Seismic Time-lapse Survey
2. VSP
3. Magnetotelluric Sounding
4. EM Resistivity
5. EMIT
6. Injection Well Logging (Wireline Logging)
7. Annulus Pressure Monitoring
8. Pulsed Neutron Capture
9. ERT
10. Sonic (Acoustic) Logging
11. 2-D Seismic Survey
12. Time-lapse Gravity
13. Density Log (RHOB Log)
14. Optical Log
15. Cement Bond Log (Ultrasonic Well Logging)
16. Gamma Ray Logging
17. Microseismic (Passive) Survey
18. Crosswell Seismic Survey
19. Aqueous Geochemistry
20. Resistivity Log

1. Multi-component 3-D Surface Seismic Time-lapse Survey (Secondary)

- *Description:* Three-dimensional surface seismic surveys are a widely deployed technology in oil and gas exploration that utilizes surface sources (e.g., dynamite or vibrating machines) to generate downward propagating elastic waves that are reflected from subsurface features and return to the surface where they are recorded by ground motion sensors (geophones), resulting in a three-dimensional view of the subsurface. In the case of a 3-D survey, a regular 2-D grid of surface sources and sensors is deployed. The recorded data are combined to produce a 3-D image of the subsurface. Conventional surface seismic surveys record only compressional, or P-waves. Multicomponent seismic surveys can be used to record both P-waves and shear, or S-waves; this is achieved by recording all components of the returning wavefield. Each sensor within a multicomponent recording cable comprises three orthogonally oriented geophones for land acquisition, plus a hydrophone for marine acquisition (hence four-component or 4C). P-waves are detected primarily by the Z-component geophone and the hydrophone, while S-waves are detected primarily by the X- and Y-component geophones.
- *Application:* In a monitoring program, an initial seismic survey contributes to geologic site characterization. In addition, the survey provides an initial baseline that can be compared to changes in subsequent seismic surveys to create a time lapse image of CO_2 plume migration and to detect significant leakage or migration of CO_2 from the storage site. Surface seismic techniques provide detailed spatial resolution of CO_2 distribution, but are less sensitive than well-based methods and, therefore, require the presence of large volumes for detection of CO_2 (Monea et al., 2008). Tracking CO_2 flood fronts and sweep efficiency over time following the injection period (4-D seismic) is another application of 3-D seismic and is an important tool for determining plume location relative to predictive modeling results.
- *Benefits:* 3-D seismic is the available technique that assesses the entire earth volume with the highest resolution; other techniques sample either a fraction of the volume (near wells, along 2-D lines, etc.). Time lapse images (4-D can be used to measure change and confirm prediction's) derived from good quality 3-D seismic are good communication tools
- *Challenges:* Semi-quantitative estimate of the distribution of CO_2: not sensitive to dissolved or thin CO_2 plumes; seismic response not linear with concentration; therefore, cannot be used to quantify volume stored. There are environmental impacts associated with using underground explosions or vibroseis trucks, clearing vegetation to install geophones, or building new roads to transport equipment and personnel. 3-D quality and sensitivity varies depending on rock and fluid properties, geometries, etc. Seismic will not work well in some settings. Noise from static errors can cause anomalies on repeat surveys and may decrease confidence unless follow-up assessment is budgeted

2. Vertical Seismic Profile (Potential)

- *Description:* VSP provides valuable information about the geologic structure of the subsurface and is one of the best ways to study seismic anisotropy. In VSP exploration, seismic energy is periodically imparted into the Earth's subterranean formations with a surface source at or near a well borehole. The seismic waves thus generated can be detected along the length of the well bore with a receiver, which utilizes signals characteristic of the Earth's response to the imparted seismic energy. The response signals are used to produce a vertical seismic profile of the Earth's subterranean formations surrounding the well bore.

- *Application:* Classic use is to depth correct a seismic survey (to tie horizons measured in time to those observed with wireline logs or cores in wells). Added value is to increase resolution relative to surface seismic, so that thin zones can be detected, for example if the CO_2 plume is thin. VSP provides high-resolution seismic image of the immediate vicinity of the borehole. VSP can be implemented in a "walk-away" fashion to monitor the footprint of the plume as it migrates away from the injection well. Walk-away VSP is employed by placing the source progressively further and further down-gradient from the injection well in order create an offset at the surface as the receivers are held in a fixed location. This technique yields a mini 2-D seismic line that can be of higher resolution than surface seismic data and provides more continuous coverage than an offset VSP. Furthermore, walk-away VSPs with receivers placed above the reservoir can be an effective method to quantify seismic attributes and calibrate surface seismic data.
- *Benefits:* Technology can provide robust information on CO_2 concentration and migration in the vicinity of a single well bore and delineate potential migration pathways (e.g., fractures).
- *Challenges:* Application limited to monitoring in a limited area surrounding a wellbore.
- *Geologic Storage Experience:* VSP will be used by the RCSPs (MRCSP, SECARB, SWP, and WESTCARB) during their Phase II projects to evaluate cap rock integrity in the vicinity of the CO_2 injection well.

3. Magnetotelluric Sounding (Potential)

- *Description:* Natural-source, electromagnetic geophysical method for imaging structures below the Earth's surface by mapping the spatial variation of the Earth's resistivity using electrical currents (or telluric currents) created by natural variations in the Earth's magnetic field. The Earth's naturally varying electric and magnetic fields are measured over a wide range of frequencies (0.0001 to 10,000 Hz). Concurrent measurements of orthogonal components of the electric and magnetic fields permit the calculation of the impedance tensor, which is complex and frequency-dependent. Using this tensor, it is possible to gain insight into the resistivity structure of the surrounding material (Cantwell, 1960).
- *Application:* The magnetotelluric sounding method was originally used for academic research. It was used successfully for the mapping of geothermal reservoirs starting in the early 1980s and became a standard application. In recent years, magnetotellurics has also become increasingly popular in oil and mineral exploration. DOE and the National Nuclear Security Administration (NNSA) at their Nevada Site Office addressed ground-water contamination resulting from historic underground nuclear testing and used magnetotelluric sounding to define the character, thickness, and lateral extent of the pre-Tertiary confining units (Williams et al., 2007).
- *Benefits:* Can probe the Earth to depths of several tens of kilometers.
- *Challenges:* Requires further development for monitoring of CO_2 movement. The resolution of magnetotelluric surveys is limited by the diffusive nature of electromagnetic propagation in the earth; it is usually on the order of hundreds of meters to kilometers.
- *Geologic Storage Experience:* For planned use of magnetotelluric sounding by the RCSPs, see Table 5-1.

4. Electromagnetic Resistivity (Potential)

- *Description:* EM is a technique used to measure the electrical conductivity of the subsurface, including soil, groundwater, rock, and buried objects. Electromagnetic techniques are sensitive to rock pore fluids within the subsurface, and they have been proposed for imaging CO_2 in EOR. Electromagnetic data are commonly presented as contour plots.
- *Application:* An important consideration in any EOR application is to distinguish between injection stream and gases, injected fluids, and formation fluids. The sensitivity of electromagnetic response to pore fluids, coupled with advances in computational capability, inversion code resolution, and field instrumentation, make borehole EM techniques a potential tool for such subsurface imaging applications (Kirkendall and Roberts, 2001). EM meters respond strongly to

metal, which can be an advantage when the target is metallic, but surveys can be affected by extraneous metallic objects, for example well casings.

- *Benefits:* Soil-to-instrument contact is not required, allowing much more rapid data acquisition over other resistivity techniques (which utilize metal pins inserted into the ground) and overcomes coupling problems that can be associated with Ground Penetrating Radar (GPR) methods.
- *Challenges:* EM meters respond strongly to metal. This can be an advantage when the target is metallic, but surveys can be affected by extraneous metallic objects, such as wells. Resolution is often a challenge.
- *Geologic Storage Experience:* Frio pilot tested cased hole–cross-well EM, but well spacing was too close for successful use with steel casings.

5. Electromagnetic Induction Tomography (Potential)

- *Description:* EMIT is a promising new tool for imaging electrical conductivity variations in the Earth. Crosswell EM imaging takes advantage of the differences in the way electromagnetic fields are induced within various materials (Kirkendall and Roberts, 2002). For example, rocks containing a lot of water, typically in the form of droplets bound to tiny rock pores, usually conduct electricity better than rocks containing CO_2. The technique uses magnetic fields to image the subsurface; it was developed for use by the oil and gas industry to determine where reserves are located. The electromagnetic source field is produced by induction coil (magnetic dipole) transmitters deployed at the surface or in boreholes. Vertical and horizontal component magnetic field detectors are deployed in other boreholes or on the surface. Sources and receivers are typically deployed in a configuration surrounding the region of interest. Although such electromagnetic field techniques have been developed and applied, the algorithms for inverting the magnetic field data to produce the desired images of electrical conductivity have not kept pace. EMIT is capable of mapping the changes in resistance of subsurface formations using magnetic fields.
- *Application:* EMIT is used to generate 3-D images of passive electromagnetic properties in the subsurface for applications such as site characterization and plume tracking. EMIT has shown success being deployed in petroleum applications for field characterization and steam flood monitoring (Berryman et al., 2000).
- *Benefits:* Electrical techniques show promise of quantifying saturation through a broader range than acoustic techniques, and joint inversion might be productive. EMIT provides greater resolution and petrophysical information that ERT.
- *Challenges:* Relatively new technology that needs further development to accurately and systematically invert magnetic field data to produce images of electrical conductivity. Technology requires a robust computational and equipment package. It is more difficult to execute and requires non-conductive casing downhole to obtain high-frequency data.

6. Injection Well Logging (Wireline Logging) (Primary)

- *Description:* One of the commonest methods for evaluating geologic formations is the use of well logs. Logs are conducted by lowering an instrument into the well and taking a profile of one or more physical properties along the length of the well. A variety of well logs is available that can measure several parameters from the condition of the well to the composition of pore fluids and the mineralogy of the formation.
- *Application:* Well logs for CCS projects will be most useful for detecting the condition of the well and ensuring that the well itself does not provide a leakage pathway for CO_2. Several logs are routinely used for this purpose, including temperature, noise, casing integrity, and radioactive tracer logs (Benson et al., 2002). However, the resolution of well logs may not be sufficient to detect very small rates of seepage through microcracks (Benson and Meyer, 2002). Several wireline logging technologies are described in this appendix.
- *Benefits:* Very useful for wellbore leakage.
- *Challenges:* Area of investigation limited to immediate wellbore.

7. Annulus Pressure Monitoring (Primary)

- *Description:* The most common internal MIT done pursuant to the UIC program is the standard annular pressure test (SAPT). The SAPT is a simple test, wherein the annular space between the tubing and casing is subjected to pressure above hydrostatic, and if the pressure can be maintained for a specified period of time within a specified percentage of loss or gain, the well is deemed to have passed. Most commonly, the SAPT is complimented by the cementing records external, or prong two, MIT. Test pressures ranging from 200 psi up to 2,500 psi are used (U.S. EPA, 1998). The testing interval is most commonly 30 minutes, but the allowable percentage of pressure gain or loss varies widely. The SAPT is most often performed with water in the annulus and water as the pressurizing agent. However, most jurisdictions allow the use of nitrogen or compressed air as the pressure source, if the annulus is liquid filled. Complete testing requirements as outlined by EPA can be found at: http://www.epa.gov/region5/water/uic/r5guid/r5_05.htm. Positive annular pressure can be maintained as a leakage-prevention measure and to assure that the packer is seated; high frequency readouts (seconds to daily) can be recorded or transmitted to monitoring site with alarm to provide high assurance of correct well performance.

- *Application:* Used to test the integrity of the annular space between the tubing and the well casing.
- *Benefits:* Testing procedure to ensure the integrity, longevity, and function of injection wells under the UIC program. Suite of required equipment is minimal.
- *Challenges:* Short duration test cannot assure absence of slow leakage if elevated pressure over long periods of time. Constant positive pressure maintenance requires maintenance of readout.
- *Geologic Storage Experience:* Positive annular pressure with real-time readout to assure current well performance was used at Frio test and SECARB's Phase II test at Cranfield.

8. Pulsed Neutron Capture (PNC) (Secondary)

- *Description:* Changes in fluid composition from brine to CO_2 respond strongly to pulsed neutron methods, for example thermal decay logging and carbon/oxygen (C/O) ratio. Various pulsed neutron techniques can be combined in one tool for greater analytical capabilities, one tool that can be lowered into the cased well and is capable of assessing oil saturation, lithology, porosity, oil, gas, and water as a function of well depth using pulsed neutron techniques. Most rigorous quantification of CO_2 change in saturation is obtained by measuring the change in pulsed neutron response (sigma) in time lapse that is by comparing logs run after CO_2 plume development to a baseline collected prior to injection. Wellbore correction logs provide fluid properties and temperature.
- *Application:* In addition to the measurements discussed above, PNC is used to identify leakage through the cemented annular space of the well in geologic CO_2 sequestration applications.
- *Benefits:* A wireline technique that can be used to quantify CO_2 saturation near the well bore. Log can be run through steel casing and tubing.
- *Challenges:* Sensitive to wellbore conditions and requires correction. Workover by low or high salinity water modifies fluid and especially degrades pulsed neutron response. Fluid characteristics identified only in the vicinity of the wellbore.

9. Electrical Resistivity Tomography (Potential)

- *Description:* ERT is a geophysical technique for imaging subsurface structures from electrical measurements made at the surface or by electrodes in one or more boreholes. It is a subsurface imaging technology that measures electrical resistivity in soil and rock. This technology can be used to obtain "snapshot" images of relatively static subsurface conditions for site screening or characterization. It can also be used to obtain a series of images showing the relatively rapid changes caused during environmental remediation. An ERT, for near-surface and subsurface imaging, data acquisition system acquires a series of voltage and current measurements from surface electrode arrays or electrode arrays emplaced underground. The electrode arrays consist of electrode dipoles that communicate with other dipoles. The electrode dipoles are fastened at regular intervals (typically five feet apart) to a supporting shaft or string. The electrode arrays can be spaced close to each other or hundreds of feet apart, depending upon the resolution needed.
- *Application:* ERT works well in both the vadose (unsaturated) and saturated subsurface zones. The extensive data resulting from measurements taken between the electrode arrays are processed to produce electrical resistivity tomographs using state-of-the-art inversion algorithms. These calculated tomographs

show spatial variations in electrical resistivity. The tomographs show the location and shape of electrical resistivity zones, and these images can be used as a guide for focusing more detailed characterization and monitoring evaluations (Newmark et al., 2001). ERT for subsurface imaging was developed for DOE's Office of Science and Technology (OST) by LLNL. ERT commonly operates in one of two modes. For in-situ applications, ERT uses electrodes on the ground surface or in boreholes. In some cases, these are spaced electrode arrays as strings or mounted on casing (Daily et al., 2004). Alternatively, previously installed casing may also serve as single long electrodes; this second mode is called long electrode electrical resistance tomography (LEERT) (Binley et al., 1999).

- *Benefits:* Can detect change in fluids (gas substitution for water). Depth of penetration of a surface array depends on the rock and fluid properties.
- *Challenges:* Requires installation of large electrode array around site. Data quality decreases as electrodes are placed further apart. Technology needs further development for monitoring CO_2 movement. Likely poor to no sensitivity to leaks occurring as dissolved fluids.
- *Geologic Storage Experience:* ERT is being tested in both surface and crosswell arrays at a shallow injection zone at the CO_2 Sink project at Ketzin, near Berlin, Germany.

10. Sonic (Acoustic) Logging (Primary)

- *Description:* A sonic log is a porosity log that measures interval transit time (Δt) of a compression sound wave travelling through one foot of formation. Sonic logging is essential to calibration of surface seismic methods. The sonic log device consists of one or more sound transmitters and two or more receivers. Sonic logs are compensated for borehole size variations, as well as for errors due to tilt of the sonic tool. Interval transit time (Δt) in microseconds per foot is the reciprocal of the velocity of a compression sound wave in feet per second. A sonic derived porosity curve is usually recorded along with the Δt curve. Sonic logs generally have additional information recorded with them, which may include a caliper log, gamma ray log, or an SP log. The interval transit time (Δt) is dependent on both the lithology and porosity, so a formation's matrix velocity must be known to derive the sonic porosity. This can be done by using a chart or by following the Wyllie formula below.

$$\phi_{sonic} = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$$

where ϕ_{sonic} = Sonic derived porosity
Δt_{log} = Interval transit time of the formation
Δt_{ma} = Interval transit time of the matrix
Δt_f = Interval transit time of the fluid in the well bore

The Wylie formula for calculating sonic porosity can be used to determine porosity in consolidated sandstones and carbonates with intergranular porosity or intercrystalline porosities. However, when sonic porosities of carbonates with secondary vuggy or fracture porosity are calculated by the Wylie formula, porosity values will be too low. This is because the sonic log only records matrix porosity. Total porosity can be obtained by using one of the nuclear logs (density or neutron). In full waveform sonic logging, the complete acoustic wave at each receiver is recorded digitally. The character of the acoustic signal detected by the receivers is affected by, among other things, the mechanical properties of the rock around the borehole. In addition, sonic logs represent one of the best ways to tie seismic data to the actual subsurface conditions. The well to seismic ties are usually done after final seismic processing, assuming that the seismic data are of high quality with no significant problems.

- Application: Sonic log uses include determination of porosity in porous rocks, measurement of permeability in porous rock, detection of fractures, and even lithology characterization (Paillet and White, 1982).
- Benefits: Sonic velocity contrast between water and CO_2 is strong, so that this log type can be used to assess changes in fluid as the CO_2 plume moves past the wellbore. Some sonic logs can be collected in cased wells. Sonic logs can be converted to synthetic seismograms to effectively tie site specific well bore information to seismic lines, thereby converting the data to a more spatial applications.

- *Challenges:* The technique only measures sound travel time and requires additional data manipulation to arrive at porosity. No standard protocol for conversion from travel time to porosity; there are many variations of the travel time/porosity relationship.
- *Geologic Storage Experience:* Acoustic logs were successfully used to detect CO_2 at the Nagaoka project, Japan. Acoustic logs were tested at the Frio project and showed change in the interval where CO_2 was present, but signal could not be quantified

11. 2-D Seismic Survey (Secondary)

- *Description:* Reflection seismic is a method that allows imaging of changes in the subsurface geology by inducing an acoustic wave from near the surface of the Earth and listening for the echoes from deeper stratigraphic boundaries. 2-D seismic is recorded using straight lines of receivers crossing the surface of the Earth. Acoustic energy is usually provided by the detonation of explosive charges or by large vibroseis trucks. The sound spreads out through the subsurface as a spherical wave front. Interfaces between different types of rocks will both reflect and transmit this wave front. The reflected signals return to the surface where they are observed by sensitive microphones known as geophones. The signals detected by these devices are recorded and sent to data processors where they are adjusted and corrected for known distortions. The final processed data is displayed in a form known as "stacked" data. The resulting profile is visualized as a 2-D slice through the Earth.
- *Application:* In a monitoring program, an initial seismic survey contributes to geologic site characterization. In addition, the survey provides an initial baseline that can be compared to changes in subsequent seismic monitoring surveys to create a time lapse image of CO_2 plume migration and to detect significant leakage and migration of CO_2 from the storage site (Monea et al., 2008).
- *Benefits:* No wellbores or drilling needed to characterize subsurface.
- *Challenges:* Very energy intensive technique. Environmental impacts associated with using underground explosions or vibroseis trucks, clearing vegetation to install geophones, or building new roads to transport equipment and personnel.

12. Time-lapse Gravity (Potential)

- *Description:* A gravity survey is based on the premise that a target is restricted in space and has a different density from the surrounding geology, e.g. that a 'pool' of gas has collected at shallow depth. This technique employs measurements of the gravitational field at a series of different locations over an area of interest in order to monitor changes in the density of fluid resulting from leaked CO_2. For CO_2 monitoring, time-lapse gravity measurements would be expected to show a decrease as CO_2 accumulation proceeds, since CO_2 is less dense than the groundwater it replaces. The method can detect mass changes, and possibly surface deformations, induced by the storage process or by possible CO_2 leakage into the overburden.
- *Benefits:* Non-invasive surface measurement indicative of fluid change at depth.
- *Challenges:* Limited detection and resolution unless gravimeters are located just above reservoir (well-bore gravimetry). Detection threshold for CO_2 is highly site specific, depending on the reservoir's depth (deeper reservoirs are less suitable), physical properties, and the survey conditions. Then, leaked CO_2 would only be detected by gravity change if it accumulated in a shallow reservoir; leakage scenarios where it leaks along a thin (fault, well, or thin zone) flow path would not be detected. An additional problem is the difficulty of eliminating all other sources of gravity variations and noise (tides, instrument drift, regional gravity contributions, etc.) to permit interpretation of the anomaly in terms of the geologic and geophysical parameters of the localized target.
- *Geologic Storage Experience:* As proof of concept, gravity surveys were conducted at Sleipner West where CO_2 injected into the Utsira injection zone, which lies at relatively shallow (800 m) depths beneath the North Sea floor, to obtain a gravity baseline. A second test was conducted three years later to detect changes due to continued CO_2 injection. Results were favorable with better-than-expected repeatability (Hoversten and Gasperikova, 2005; Nooner et al., 2006). Gravity should be even more sensitive for a gas phase CO_2 leak.

13. Density Logging (RHOB Log) (Secondary)

- *Description:* RHOB is derived from RHO, the Greek letter used to represent density, plus B for bulk. Bulk density is the density of the formation including any fluids in the pore space. A RHOB log provides a continuous record of a formation's bulk density as a function of depth by accounting for both the density of the matrix and the density of the liquid in the pore space. RHOB measurements are typically linear, often in the interval 1.95-2.95 g/cm^3. RHOB is often measured as a combination of density-neutron together with gamma and calliper (calliper logs record borehole diameter) because gamma provides repeatability and calliper is good for quality control.
- *Application:* Used to provide a continuous record of a formation's bulk density as a function of depth.
- *Benefits:* Technology can estimate formation density and porosity at varying depths.
- *Challenges:* Lower resolution log compared to other wireline methods. High -radiation zones (uranium ore) can yield erroneous low density log values (Hill, 1993).

14. Optical Log (Secondary)

- *Description:* Camera system is lowered into a cased well for visual casing inspection. A cable feed to the surface provides the operator a screen (Cathode Ray Tube or Liquid Crystal Display). The angle of view can be rotated from looking directly down the center of the casing, to observing a portion of the side wall. Corrosion, cracks, holes, and loose joints can be detected visually. If required, ultraviolet light can be used to detect micro-fractures in the casing. The camera is equipped with a video recording device and a depth counter to pinpoint any compromised areas.
- *Application:* Lowered into a cased well for visual casing inspection.
- *Benefits:* Readily available technology.
- *Challenges:* Can be time consuming. Image quality may be poor. Stray radio frequencies can deteriorate image.

15. Cement Bond Log (Ultrasonic Well Logging) (Primary)

- *Description:* CBLs use sonic attenuation and travel time to determine whether casing is cemented or free. Cement bond logs use waveforms having frequencies that range from 200 kilohertz (kHz) to 700 kHz that are in the transmitter portion of the logging tool. A rotating acoustic sensor is employed to measure acoustic energy through a 360 degree rotation. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. Because the transducer is mounted on the rotating receiver, the entire circumference of the casing is scanned. This 360° data coverage enables the evaluation of the quality of the cement bond, as well as the determination of the internal and external casing condition. If available, a shop calibration record should be attached. The surface pressure under which the log was run should be noted on the log form. If an initial CBL does not indicate the presence of cement, often a second log will be run with pressure on the casing. This may show cement while the earlier log does not. In this case, a microannulus has developed due to past expansion of the casing while it was pressurized during operations or testing. It is sometimes necessary to pressurize the casing above the highest pressure to which it has been subjected.
- *Application:* The CBL is effective for evaluating conventional cement slurries and foam cement slurries. It performs the functions of cement evaluation, casing inspection, corrosion detection and monitoring, detection of internal and external damage or deformation, and casing thickness analysis for collapse and burst pressure calculations.
- *Benefits:* The CBL clearly indicates top of cement, free pipe, and gives an indication of well cemented pipe. Assessment of the rock-annulus not accessible by other techniques.
- *Challenges:* Good centralization is important for meaningful and repeatable CBLs; CBLs should not be relied on for a quantitative evaluation of zonal isolation or hydraulic integrity. Cement should be allowed to cure for at least 72 hours before logging. May not detect micro-annulus or channeling. Cannot assess permeability of the cement or geochemical modification, such as by interaction with CO_2.

16. Gamma Ray Logging (Secondary)

- *Description:* Technique using natural gamma radiation to characterize the rock or sediments in a borehole. Various rocks emit different amounts of natural gamma radiation. Shales, in particular, typically emit more gamma rays than other sedimentary rocks, such as sandstone, gypsum, salt, coal, dolomite, and limestone. Shales emit more gamma radiation due to elevated radioactive potassium in their clay content and because the cation exchange capacity of clays causes them to adsorb uranium and thorium. The gamma ray log is conducted by lowering an instrument down the well and recording gamma radiation as a function of depth. In the U.S., readings are most commonly taken at half-foot intervals.
- *Application:* Gamma logging is most commonly used for formation evaluation in oil- and gas-well drilling and sometimes in mineral exploration and water-well drilling.
- *Benefits:* Common measurement of the natural emission of gamma rays by a formation. Can operate through the steel and cement walls of cased boreholes because sufficient gamma radiation travels through the steel and cement to allow qualitative determinations of the formation despite some gamma absorption.
- *Challenges:* Subject to error when a large proportion of the gamma ray radioactivity originates from the sand-sized detrital fraction of the rock (Heslop, 1974; Rider, 1990).

17. Microseismic (Passive) Survey (Secondary)

- *Description:* Microseismic monitoring has been employed for about 40 years to measure down-hole processes. It is rooted in earthquake seismology; and, thus, the basic theoretical underpinnings are clearly known. The approach provides an image of fractures by detecting microseisms (micro-earthquakes) triggered by shear slippage. The location of the microseismic events is obtained using a down-hole receiver array that is positioned at depth in a second well near the injection well. Microseismic mapping can be performed in the injection well in cases where suitable offset monitoring wellbores are not available. It is common to pair microseismic and tiltmeter surveys (Figure AIII-1). Microseismic fracture mapping measures very small seismic events, commonly between M -4 and 0. However, the seismic waves attenuate in the crust, and it is often difficult to detect events that are more than 800 m away. The rate at which the waves attenuate is a function of the rock petrophysics, which can be readily measured using conventional logging tools or in petrophysical laboratories.

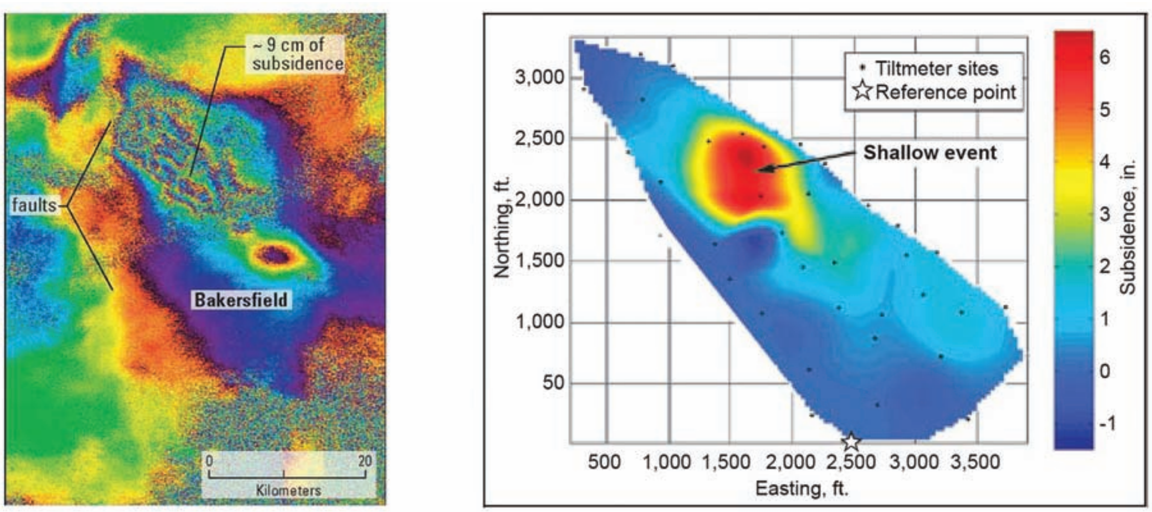

Figure AIII-1: Crustal deformation survey interpretations. (Left) Tiltmeter array interpretation from an oil field operation, revealing the location of a small change in surface elevation. Image courtesy of Pinnacle Technologies, Inc. (Right) InSAR difference map showing complex subsidence (red) and uplift (blue) associated with oil field production near Bakersfield, California, from August 1979 to September 1999. Color bands show roughly 60 millimeters of change from red to blue; resolution is one millimeter deformation. The image shows large oil fields and illustrates how faults can affect the distribution of deformation. Image courtesy of the U.S. Geological Survey (USGS).

- *Application:* Microseismic surveys are regularly used to monitor hydrofracturing in commercial oil fields, as well as to track flow fronts and pressure waves during water injection. Passive seismic can be used to monitor the formations above the reservoir for evidence of CO_2 migration through the seal rock and assess fracture propagation.
- *Benefits:* Since passive seismic uses natural wave generators instead of a vibroseis truck or explosives, it has advantages for remote areas where it is difficult to locate vibroseis trucks and for environmentally sensitive areas. Provides a unique dataset that can be used to map the important feature of pressure through a 3-D volume. May indentify areas of weakness (fractures and faults).
- *Challenges:* Some fluid-rock systems may produce no acoustic signal. Inversions can yield some location uncertainty; incorrectly located events can add uncertainty.
- *Geologic Storage Experience:* Anneth.

18. Crosswell Seismic (Potential)

- *Description:* Crosswell seismic is conducted between wells with the source and receivers placed inside sets of wellbores. The receiver arrays are held fixed in one or more wells, while the source is slowly drawn upwards (source run) in the other well and is "fired" at preset intervals. The receivers are relocated and the source run is repeated. Typical spacing between adjacent source points ranges from 2.5 feet (0.8 meters) to 20 feet (6 meters). Receiver separation is usually similar. It is possible for these systems to acquire 20,000 or more traces in a single, 24-hour day. A complete survey can be as small as a few thousand traces or as large as several hundred thousand traces. Such factors as the well separation, the thickness and structure of the imaging target, and the frequency content of the received signal dictate the necessary size of a survey. Crosswell surveys typically utilize a frequency band ranging from 20 to 2,000 Hz, depending on the type of source used, the distance between wells, and the attenuation characteristics of the zone under investigation. Resolution on the order of 10 feet (3 meters) is possible. Crosswell processing is similar to surface seismic processing in that it includes velocity estimation (travel time tomography) and reflection imaging. Reflection imaging provides more resolution than the velocity image (tomogram) and depends significantly on the accuracy of the velocity model for good results.
- *Application:* Crosswell profiling is a technology for reservoir delineation, development, characterization, and monitoring, but not exploration. Monitoring changes in reservoir conditions (e.g. saturation or pressure) is quite effective, but monitoring requires multiple visits to the same site in order to obtain time-lapse images. Imaging of reservoir properties (e.g., porosity), can be successful and contribute to characterization (Harris and Langan, 2001). A special case of crosswell surveillance—Continuous Active Seismic Source Monitoring (CASSM)—was developed by LBNL (Daley, et al., 2007) for deployment at Frio. In this method, the source array and receiver string were run in the wells on tubing and left in place as the injection proceeded, providing real time data on plume migration .
- *Benefits:* Crosswell seismic profiling provides higher resolution than surface methods but samples a smaller volume.
- *Challenges:* Mass of CO_2 and dissolution/mineral trapping are not measured by seismic techniques. Wells must be controlled (run in imperforated boreholes or CO_2 pushed back from the sand face by "kill" fluids) prior to running surveys; this limits opportunities for geochemical or well-based monitoring.
- *Geologic Storage Experience:* Frio, Lost Hills. Several of DOE's RCSPs are implementing crosswell seismic surveys to assess seal performance and measure plume geometry for their Phase II and Phase III injection projects.

19. Aqueous Geochemistry (Primary)

- *Description:* Measuring geochemical evolution of subsurface formation waters including dissolved CO_2, dense phase CO_2, and other fluids requires fluid sampling on a regular basis. Monitoring could be undertaken in boreholes that penetrate the reservoir or in monitoring wells that penetrate overlying formations. Measurements could include parameters, such as: pH, HCO_3^{-2}, alkalinity, dissolved gases, hydrocarbons, major and minor elements, TIC, TOC, stable isotopes, redox potential, specific conductance, TDS, density, natural and introduced tracers. It is important to design the sample retrieval system that will conserve the properties that are required for analysis. Fluid mixtures (CO_2-brine plus any other relevant gases or hydrocarbons) will density-separate in the wellbore, and this fractionation will increase as fluids move upward through tubing and gases expand and become less dense. Temperature and solubility relationships will also change, for example gas in solution will evolve. If needed, several techniques can be used to reduce these complications.

- *Application:* Commercial downhole sampler systems can be deployed on wireline or slickline to collect samples at reservoir pressure and temperature and then conserve this volume during transport to the surface. A U-tube sampler was designed for the Frio Project that allows samples to be returned to surface at near reservoir pressures (Freifeld and Trautz, 2006). The U-Tube is composed of a double length of high pressure stainless steel tubing with a check valve open to the reservoir. Formation fluid is collected in the U-Tube, driven at reservoir pressure into evacuated sample cylinders at the surface by high-pressure, ultra-pure nitrogen. Free gas in the sample and gases coming out of solution are pumped from the top of the gas separator through a quadrapole mass spectrometer analyzer and a landfill gas analyzer to measure changes in gas composition in the field (Figure AIII-2). Geochemical analysis must also be matched to the analysis requirements, which may require measurement of gas and liquid fractions at known pressure and temperature, collection of field parameters, filtration, stabilization, labeling, storing, and shipping samples.
- *Benefits:* Geochemistry provides detailed information needed to confirm model predictions. In particular, it is the only technique available that has promise to document dissolution and mineral trapping or, conversely, any geochemical interactions that may lead to increased risk (e.g., damage to formation, confining zone, or engineered system).
- *Challenges:* Requires well penetration, well perforation, and sampling apparatus and personnel. Well drilling and completion causes contamination of the near well-bore environment with allochthonous fluids; that must be reduced and corrected for. Extraction of fluids is labor-intensive, requiring a gas lift or pumping system except where pressure or gas saturation are high enough to lift fluids to the surface.

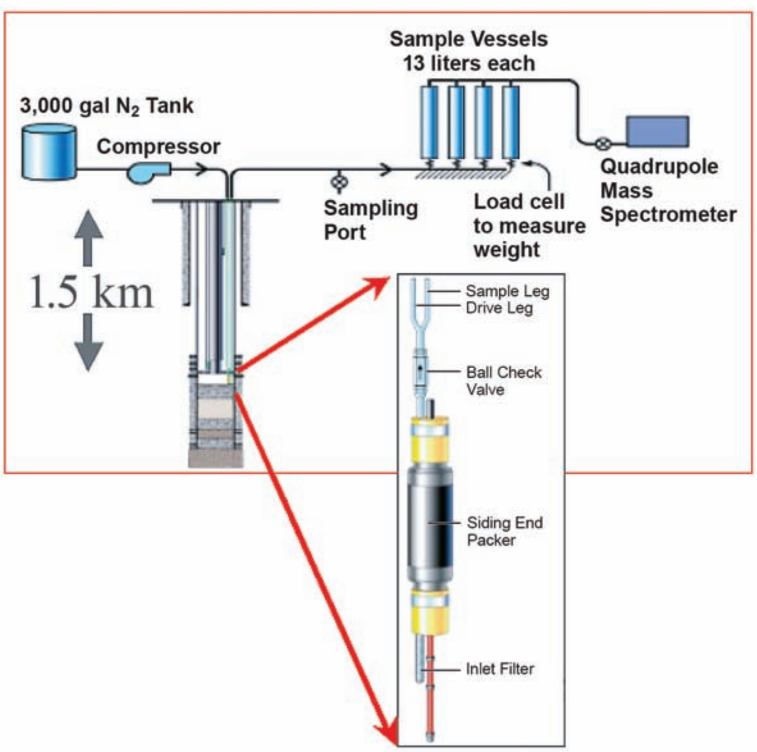

Figure AIII-2: Schematic Drawing of the U-Tube Sampling Technology

- *Geologic Storage Experience:* Weyburn had an extensive fluid sampling effort that documented rock-water-CO_2 interaction. Frio also had high quality frequency sampling to document breakthrough, transport properties, and geochemical reaction. Otway had geochemical sampling to document breakthrough and tracer movement.

20. Resistivity Logs (Secondary)

- *Description:* A log of the resistivity of the formation, expressed in ohm-meters, to characterize the rock or sediment in a borehole. The resistivity may cover a wide range of values and, for convenience, is usually presented on a logarithmic scale from (for example) 0.2 to 2,000 ohm-m. Resistivity is measured using four electrical probes to eliminate the resistance of the contact leads. The log must be run in wells containing electrically conductive fluid (mud or water). The resistivity log is fundamental in formation evaluation, since hydrocarbons do not conduct electricity, while all formation waters do. Therefore, a large difference exists between the resistivity of rocks filled with hydrocarbons and those filled with water.
- *Benefits:* High-resolution technique used to characterize the subsurface.
- *Challenges:* Resistivity logs are affected by bed thickness, borehole diameter, and borehole fluid and can only be collected in water- or mud-filled open wells.

APPENDIX III REFERENCES

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Appendix IV

Summary of the Purpose for Monitoring During the Phases of a Geologic Storage Project

Monitoring Activity	Monitoring Phase			
	Pre-Operational	**Operational**	**Closure**	**Post Closure**
Establishing baseline conditions from which the impacts of CO_2 storage can be assessed	Yes			
Ensure effective injection controls		Yes		
Detect the location of the CO_2 plume		Yes	Yes	
Assessing the integrity of shut-in, plugged, or abandoned wells	Yes	If leakage detected	If leakage not stopped	If leakage not stopped
Identify and confirm storage efficiency and processes	Yes	Yes		
Model calibration and performance confirmation – comparing model predictions to monitoring		Yes	Yes	
Detect and quantify surface seepage		If leakage detected	If leakage not stopped	If leakage not stopped
Assess health, safety, and environmental impacts of leakage		If leakage detected	If leakage not stopped	If leakage not stopped
Monitoring micro-seismicity associated with CO_2 injection	Yes	If micro-seismicity detected		
Monitoring to design and evaluate remediation efforts		If leakage detected	If leakage detected	
Provide assurance and accounting where monetary transactions are involved, such as with carbon trading and emission tax or emission reduction incentives.		Yes	Yes	
Evaluating interactions with or impacts on other geological resources (e.g., nearby water, coal, oil & gas, mineral reserves or other geological waste disposal operations.		If interactions are possible	If interactions are possible	If interactions are possible
Settling of legal disputes due to leaks, seismic events, or ground movement		If leakage, seismicity or ground movement detected	If leakage, seismicity or ground movement detected	If leakage, seismicity or ground movement detected
Assuring the public when visibility and transparency is of prime importance		Yes	Yes	

Appendix V

Overview of RCSP Projects Related to UIC Program

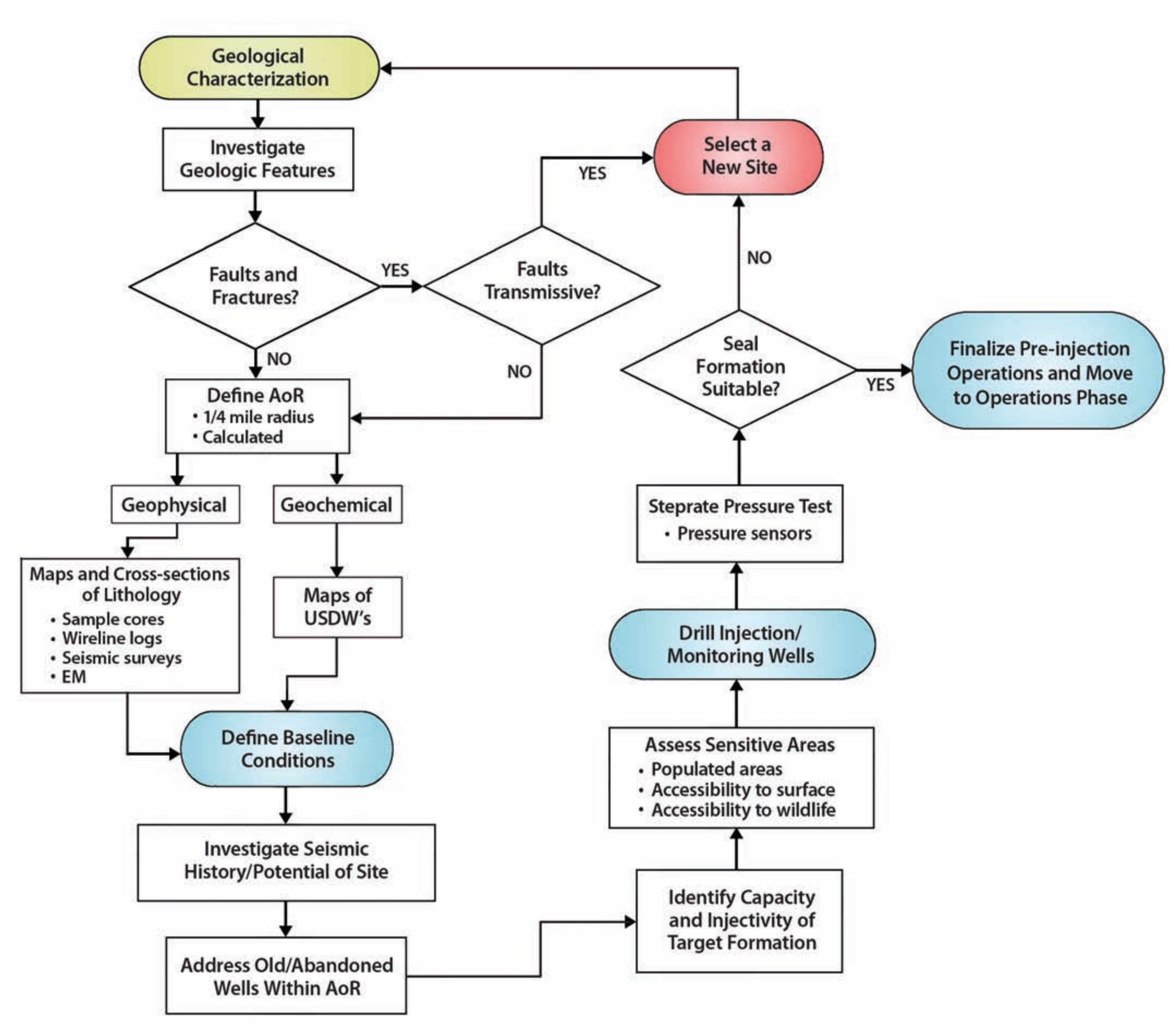
Geologic Province	Target Formation Geology	Formation Type	Total Injection (tons CO_2)	Approximate Depth (ft)	Permit Class	Permitting Agency
Appalachian Basin	Oriskany and Clinton Sandstone	Saline formation	1,000–3 ,000	5,900–8,300	Class V	Ohio EPA
Cedar Creek, Billings, or Nesson Anticline	Carbonate Formation	Oil-bearing	3–6 million	9,800–11,250	Class II	
Cincinnati Arch	Mt. Simon Sandstone	Saline formation	1,000–3,000	3,200–3,500	Class V	EPA Region IV
Colorado Plateau	Sandstone and Limestone	Saline formation	2,000	3,500	(1) Class V (2) Exploratory Stratigraphy Permit (3) Temporary Individual Permit	(1) EPA Region 9 (2) Arizona Oil and Gas Conservation Commission (3) Arizona Department of Environmental Quality
Columbia Basin	Basalt Formation	Saline formation	3,000	3,255–3,335 & 3,600–3,755	Class V	Washington Dept. of Ecology
Desert Creek and Ismay Zones	Carbonate Formation	Oil-bearing	450,000–750,000	5,600–5,800	Class II	Navajo EPA and Federal EPA
Devonian-aged rock	Carbonate Formation	Saline formation	11 million	6,500–7.500	NA	NA
Duperow Formation	Carbonate Formation	Oil-bearing	3,000–5,000	2,500–4,000	Class II	North Dakota Industrial Commission
Entrada	Sandstone Formation	Saline formation	4 million	8,000	Class V	EPA Region 8
Harmon Coal Seam	Lignite Coal Seam	Coal seam	<1,000	1,600–1,800	Class II	North Dakota Industrial Commission
Horseshoe Atoll Play and Pennsylvanian Reef/Bank Play	Carbonate Formation	Oil-bearing	900,000	5,800	Class II	Texas Railroad Commission
Illinois Basin	Mississippi Weiler Sandstone	Oil-bearing Heavy	300	1,550	Class II	Illinois DNR Oil & Gas Division
	TBD	Oil-bearing Well Conversion	300	1,549	Class II	Illinois DNR Oil & Gas Division
	TBD	Oil-bearing Pattern Flood I	300	1,548	Class II	Illinois DNR Oil & Gas Division
	TBD	Oil-bearing Pattern Flood II	300	1,551	Class II	Illinois DNR Oil & Gas Division
	Mt. Simon Sandstone	Saline formation	10,000	7,000-8,600	Class I	Illinois EPA

Geologic Province	Target Formation Geology	Formation Type	Total Injection (tons CO_2)	Approximate Depth (ft)	Permit Class	Permitting Agency
Lower Tuscaloosa	Sandstone Formation	Saline formation	3 million	10,000–10,500	Class V	Mississippi Oil and Gas Board
Lower Tuscaloosa	Sandstone Formation	Saline formation	400,000–1 million	8,500–9,000	Class V	Primacy State (MS, AL, FL)
Lower Tuscaloosa Massive Sand Unit	Sandstone Formation	Saline formation	3,000	8,600	Class V (Permitted to Class I Requirements)	Mississippi Department Environmental Quality
McCormick Sand	Sandstone Formation	Saline formation	1,000	3,400–3,500	Class V	EPA Region 9
Michigan Basin	Bass Island Dolomite	Saline formation	3,000–20,000	3,200–3,500	Class V	EPA Region V
Middle Capay Shale	Shale Formations	Gas-bearing	500	3,050	Test Well (Class II)	California Division of Oil, Gas, and Geothermal Resources (DOGGR)
Middle Devonian Keg River	Carbonate Formation	Oil-bearing	250,000 (CO_2) 90,000 (H_2S)	5,000	Class II	Alberta Energy and Utilities Board
Moxa Arch LaBarge Platform	Nugget Sandstone	Saline formation	3 million	11,000	Class V	Wyoming Department of Environmental Quality (WDEQ)
Pocahontas and Lee Formations	Coal Formation	Coal seam	1,000	1,600–2,300	Class II	EPA Region III and Virginia Department of Mines & Minerals
Pottsville Formation	Black Creek, Mary Lee, and Pratt Coal Zones	Coal seam	1,000	1,500–2,500	Class II	Alabama Oil & Gas Board
Stevens, Olcese, or Vedder Sandstones	Sandstone Formation	Saline formation	1 million	7,000–9,000	Class V	Uncertain – likely EPA
Tuscaloosa Formation	Sandstone Formation	Oil-bearing Saline formation	>800,000/yr	10,066	Class II	Mississippi Oil and Gas Board
Upper Cretaceous Fruitland Formation	Coal Formation	Coal seam	75,000	3,000	Class II	Mew Mexico Oil Cons. Division and Federal BLM

Appendix VI

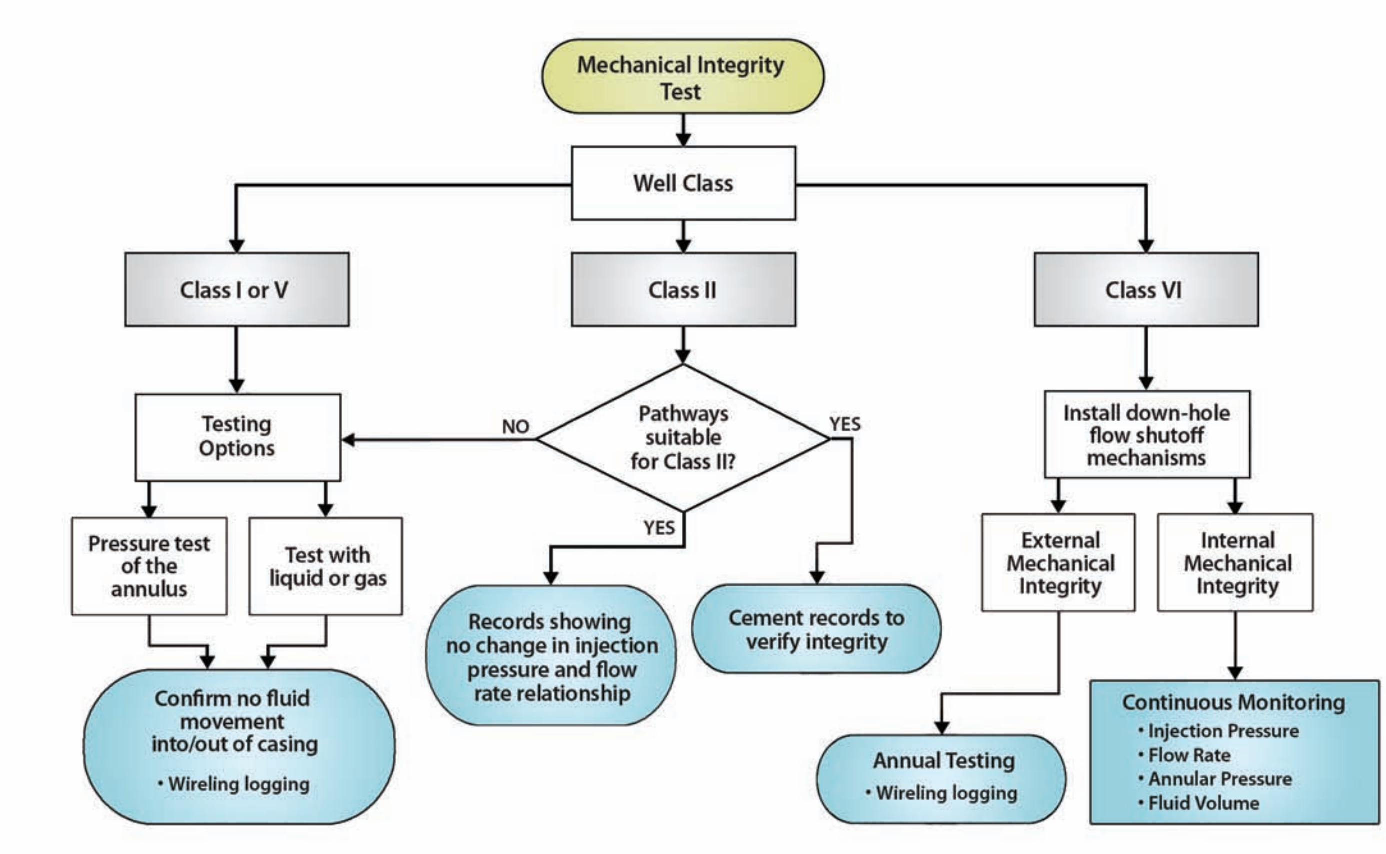
Site Characterization and Mechanical Integrity Testing Detailed Decision Trees

Site Characterization



Typical site characterization procedure for a given GS project that includes mandatory siting requirements pursuant to 40 CFR § 146.14 & 146.24

Mechanical Integrity Testing



MIT Pathway Based on Regulations Set Forth in 40 CFR § 146.8
and the Proposed Regulations for UIC Class VI Injection Wells

List of Reviewers

The following individuals/organizations provided technical insight that was critical to the development of this document.

Susan Hovorka
Gulf Coast Carbon Center. Bureau of Economic Geology. The University of Texas at Austin

Lee Spangler
Montana State University

Bruce Kobelski
Underground Injection Control Program – U.S. EPA

Julianna Fessenden
Los Alamos National Laboratory

Tom Daley
Lawrence Berkeley National Laboratory

Lydia Cumming
Battelle Memorial Institute

Neeraj Gupta
Battelle Memorial Institute

Stephanie Wolfe
University of North Dakota – Energy & Environmental Research Center

Richard Hammack
National Energy Technology Laboratory – Geosciences Division

Nick Woodward
U.S. Department of Energy – Office of Science

Comments from the U.S. Environmental Protection Agency

Contacts

If you have any questions, comments, or would like more information about DOE's Carbon Sequestration Program, please contact the following persons:

Sean Plasynski
Carbon Sequestration Program Technology Manager
Strategic Center for Coal
412-386-4867
sean.plasynski@netl.doe.gov

Dawn Deel
Monitoring, Verification, and Accounting Focal Lead
Strategic Center for Coal
304-285-4133
dawn.deel@netl.doe.gov

John Litynski
Sequestration Division Director
Strategic Center for Coal
304-285-1339
john.litynski@netl.doe.gov

Document Prepared by:

Coordinating Lead Author:
Rameshwar D. Srivastava, Ph.D - SAIC/NETL

Lead Authors:
Bruce Brown - SAIC/NETL
Timothy R. Carr, Ph. D - WVU/SAIC
Derek Vikara - SAIC/NETL

Contributing Author:
Howard McIlvried, Ph.D - SAIC/NETL

Quality Assurance/Control:
Joseph Giardina - SAIC/NETL
Gregory Washington - SAIC/NETL

Contract Information 41817.311.01.10.003

NATIONAL ENERGY TECHNOLOGY LABORATORY

1450 Queen Avenue SW
Albany, OR 97321-2198
541-967-5892

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880
304-285-4764

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940
412-386-4687

WEBSITE: **www.netl.doe.gov**

CUSTOMER SERVICE: **1-800-553-7681**

U.S. DEPARTMENT OF ENERGY

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