ATTACHMENT 26

AR # 441

UIC Program Class VI Well Testing and Monitoring Guidance

United States Environmental Protection Agency

Geologic Sequestration of Carbon Dioxide

Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance

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Disclaimer

The *Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* (75 FR 77230, December 10, 2010), known as the Class VI Rule, establishes a new class of injection well (Class VI).

The Safe Drinking Water Act (SDWA) provisions and U.S. Environmental Protection Agency (EPA) regulations cited in this document contain legally-binding requirements. In several chapters this guidance document makes suggestions and offers alternatives that go beyond the minimum requirements indicated by the Class VI Rule. This is intended to provide information and suggestions that may be helpful for implementation efforts. Such suggestions are prefaced by "may" or "should" and are to be considered advisory. They are not required elements of the rule. Therefore, this document does not substitute for those provisions or regulations, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA, states, or the regulated community. The recommendations herein may not be applicable to each and every situation.

EPA and state decision makers retain the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate. Any decisions regarding a particular facility will be made based on the applicable statutes and regulations. Mention of trade names or commercial products does not constitute endorsement or recommendation for use. EPA is taking an adaptive rulemaking approach to regulating Class VI injection wells, and the agency will continue to evaluate ongoing research and demonstration projects and gather other relevant information as needed to refine the rule. Consequently, this guidance may change in the future without a formal notice and comment period.

While EPA has made every effort to ensure the accuracy of the discussion in this document, the obligations of the regulated community are determined by statutes, regulations, or other legally binding requirements. In the event of a conflict between the discussion in this document and any statute or regulation, this document would not be controlling.

Note that this document only addresses issues covered by EPA's authorities under the SDWA. Other EPA authorities, such as Clean Air Act requirements to report carbon dioxide injection activities under the Greenhouse Gas Mandatory Reporting Rule are not within the scope of this document.

Executive Summary

EPA's *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells* are now codified in the U.S. Code of Federal Regulations [40 CFR 146.81 *et seq.*], and are referred to as the Class VI Rule. The Class VI Rule establishes a new class of injection well (Class VI) and sets federal minimum technical criteria for Class VI injection wells for the purposes of protecting underground sources of drinking water (USDWs). This document is part of a series of technical guidance documents that EPA is developing to support owners or operators of Class VI wells and UIC Program permitting authorities.

The Class VI Rule requires owners or operators of Class VI wells to perform several types of activities during the lifetime of the project in order to ensure that the injection well maintains its mechanical integrity, that fluid migration and the extent of pressure elevation are within the limits described in the permit application, and that USDWs are not endangered. These activities include mechanical integrity tests (MITs), injection well testing during operation, monitoring of ground water quality above the confining zone, tracking of the carbon dioxide plume and associated pressure front, and, at the discretion of the UIC Program Director, surface air and/or soil gas monitoring. This guidance provides information regarding how to perform these testing and monitoring activities.

The introductory section reviews the Class VI regulations related to testing and monitoring and discusses the development of the Testing and Monitoring Plan. The rest of the document addresses technical issues as follows:

- Section 2 addresses mechanical integrity testing.
- Section 3 addresses operational testing and monitoring during injection.
- Section 4 addresses ground water and geochemical monitoring.
- Section 5 addresses plume and pressure-front tracking.
- Section 6 addresses surface air and soil gas monitoring.

In addition, the Appendix presents several testing and monitoring case studies. For each section in the body of the document, this guidance:

- Explains how to perform activities necessary to comply with testing and monitoring requirements (e.g., ground water monitoring, MITs). Illustrative examples are provided in several cases.
- Provides references to comprehensive reference documents and scientific literature for further information.
- Explains how and when to report to the UIC Program Director the results of activities related to testing and monitoring.

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Acronyms and Abbreviations

AGA	American Gas Association
AoR	Area of review
API	American Petroleum Institute
CEM	Continuous emission monitoring
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
CIL	Casing inspection log
CO_2	Carbon dioxide
DAS	Detailed area of study (at Cranfield)
EAGE	European Association of Geoscientists & Engineers
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERT	Electrical resistive tomography
FID	Flame ionization detector
GMT	Geomechanical test (at Cranfield)
GPS	Global positioning system
GS	Geologic sequestration
HiVIT	High volume injection test (at Cranfield)
IEA	International Energy Agency
InSAR	Interferometric synthetic aperture radar
IR	Infrared
ISG	In Salah Gas
ITRC	Interstate Technology & Regulatory Council
JIP	Joint Industry Project (at In Salah)
LBNL	Lawrence Berkeley National Laboratory
MIT	Mechanical integrity test
MRCSP	Midwest Regional Carbon Sequestration Partnership
MRV	Monitoring, Verification, and Reporting (for Subpart RR)
NDIR	Non-dispersive infrared
NETL	National Energy Technology Laboratory
NOAA	National Oceanic and Atmospheric Administration
PID	Photo ionization detector
PISC	Post-injection site care
PTRC	Petroleum Technology Research Center
QA/QC	Quality assurance/quality control
QAPP	Quality Assurance Project Plan

RCRA	Resource Conservation and Recovery Act
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SWP	Southwest Regional Partnership
TDS	Total dissolved solids
TSD	Technical Support Document
TX RRC	Texas Railroad Commission
UIC	Underground Injection Control
USDOE	U.S. Department of Energy
USDW	Underground source of drinking water
VOC	Volatile organic compound
VSP	Vertical seismic profile *or* vertical seismic profiling

Definitions

Key to definition sources:

1: Class VI Rule Preamble.
2: 40 CFR 144.3.
3: 40 CFR 146.81(d).
4: This definition was drafted for the purposes of this document based on current usage and practice.
5: EPA's UIC website (http://water.epa.gov/type/groundwater/uic/glossary.cfm).
6: 40 CFR 144.6(f) and 144.80(f).

Annulus means the space between the well casing and the wall of the borehole; the space between concentric strings of casing; space between casing and tubing.[1]

Aquifer exemption refers to a special exemption that removes an aquifer or part of an aquifer from SDWA protection when certain requirements (at 40 CFR 146.4) are met to demonstrate that the exempted aquifer does not currently serve as source of drinking water and has no real potential to be used as drinking water source in the future. One basis for demonstrating that an aquifer will not be used in the future is to show that it is mineral producing or capable of mineral production.[4]

Area of review (AoR) means the region surrounding the GS project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids and is based on available site characterization, monitoring, and operational data as set forth in 40 CFR 146.84.[3]

Carbon dioxide plume means the extent underground, in three dimensions, of an injected carbon dioxide stream.[3]

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process. This subpart [Subpart H of 40 CFR 146] does not apply to any carbon dioxide stream that meets the definition of a hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA) under 40 CFR part 261.3.[3]

Casing means pipe material placed inside a drilled hole to prevent the hole from collapsing. The two types of casing in most injection wells are (1) surface casing, the outer-most casing that extends from the surface to the base of the lowermost USDW and (2) long-string casing, which extends from the surface to or through the injection zone.[1]

Cement means material used to support and seal the well casing to the rock formations exposed in the borehole. Cement also protects the casing from corrosion and prevents movement of injectate up the borehole. The composition of the cement may vary based on the well type and purpose; cement may contain latex, mineral blends, or epoxy.[1]

Class II wells means wells that inject brines and other fluids associated with oil and gas production, or storage of hydrocarbons. Class II well types include salt water disposal wells, enhanced oil recovery wells, enhanced gas recovery wells, and hydrocarbon storage wells.[5]

Class VI wells means wells that are not experimental in nature that are used for GS of carbon dioxide beneath the lowermost formation containing a USDW; or, wells used for GS of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at 40 CFR 146.95; or, wells used for GS of carbon dioxide that have received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to 40 CFR 146.4 and 144.7(d).[6]

Confining zone means a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) that acts as barrier to fluid movement. For Class VI wells operating under an injection depth waiver, confining zone means a geologic formation, group of formations, or part of a formation stratigraphically overlying and underlying the injection zone(s).[3]

Corrective action means the use of UIC Program Director-approved methods to ensure that wells within the AoR do not serve as conduits for the movement of fluids into USDWs.[3]

Enhanced recovery wells inject substances, such as brine, steam, polymers, or carbon dioxide, into hydrocarbon-bearing formations to improve the recovery of residual oil (enhanced oil recovery) or natural gas (enhanced gas recovery).[4]

Fluid means any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas or other form or state. [2]

Formation or geological formation means a layer of rock that is made up of a certain type of rock or a combination of types.[1]

Geologic sequestration (GS) means the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations. This term does not apply to carbon dioxide capture or transport.[3]

Geologic sequestration project means an injection well or wells used to emplace a carbon dioxide stream beneath the lowermost formation containing a USDW; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at 40 CFR 146.95; or, wells used for geologic sequestration of carbon dioxide that have received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to 40 CFR 146.4 and 144.7(d). It includes the subsurface three-dimensional extent of the carbon dioxide plume, associated area of elevated pressure, and displaced fluids, as well as the surface area above that delineated region.[3]

Ground water means water below the land surface in a zone of saturation.[2]

Injectate means the fluids injected. For the purposes of the Class VI Rule, this is also known as the carbon dioxide stream.[1]

Injection depth waivers refer to the provisions at 40 CFR 146.95 that allow owners or operators to seek a waiver from the Class VI injection depth requirements for GS to allow injection into non-USDW formations while ensuring that USDWs are protected from endangerment.[4]

Injection zone means a geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or wells associated with a GS project.[3]

Mechanical integrity means the absence of significant leakage within the injection tubing, casing, or packer (known as internal mechanical integrity), or outside of the casing (known as external mechanical integrity).[1]

Mechanical integrity test (MIT) refers to a test performed on a well to confirm that a well maintains internal and external mechanical integrity. MITs are a means of measuring the adequacy of the construction of an injection well and a way to detect problems within the well system.[1]

Model means a representation or simulation of a phenomenon or process that is difficult to observe directly or that occurs over long time frames. Models that support GS can predict the flow of carbon dioxide within the subsurface, accounting for the properties and fluid content of the subsurface formations and the effects of injection parameters.[1]

Owner or operator means the owner or operator of any facility or activity subject to regulation under the UIC Program.[2]

Packer means a mechanical device that seals the outside of the tubing to the inside of the long-string casing, isolating an annular space.[1]

Post-injection site care (PISC) means appropriate monitoring and other actions (including corrective action) needed following cessation of injection to assure that USDWs are not endangered, as required under 40 CFR 146.93.[3]

Pressure front means the zone of elevated pressure that is created by the injection of carbon dioxide into the subsurface. For GS projects, the pressure front of a carbon dioxide plume refers to the zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW.[3]

Separate-phase carbon dioxide means carbon dioxide that is present in a free, or non-aqueous, gaseous, liquid, or supercritical phase state.[4]

Shut-off device refers to a valve coupled with a control device which closes the valve when a set pressure or flow value is exceeded. Shut-off devices in injection wells can automatically shut down injection activities when operating parameters unacceptably diverge from permitted values.[5]

Site closure means the specific point or time, as determined by the UIC Program Director following the requirements under 40 CFR 146.93, at which the owner or operator of a GS site (Class VI injection well) is released from PISC responsibilities.[3]

Supercritical fluid means a fluid above its critical temperature (31.1^{o}C for carbon dioxide) and critical pressure (73.8 bar for carbon dioxide). Supercritical fluids have physical properties intermediate to those of gases and liquids.[1]

Total dissolved solids (TDS) refers to the measurement, usually in mg/L, for the amount of all inorganic and organic substances suspended in liquid as molecules, ions, or granules. For injection operations, TDS typically refers to the saline (i.e., salt) content of water-saturated underground formations.[1]

Transmissive fault or fracture means a fault or fracture that has sufficient permeability and vertical extent to allow fluids to move between formations.[3]

Tubing refers to a small-diameter pipe installed inside the casing of a well. Tubing conducts injected fluids from the wellhead at the surface to the injection zone and protects the long-string casing of a well from corrosion or damage by the injected fluids.[5]

Underground Injection Control (UIC) Program Director refers to the chief administrative officer of any state or tribal agency or EPA Region that has been delegated to operate an approved UIC Program.[5]

Underground Injection Control (UIC) Program refers to the program EPA, or an approved state, is authorized to implement under SDWA that is responsible for regulating the underground injection of fluids by wells injection. This includes setting the federal minimum requirements for construction, operation, permitting, and closure of underground injection wells.[4]

Underground source of drinking water (USDW) means an aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/L TDS and is not an exempted aquifer.[1]

Well bore refers to the hole that remains throughout a geologic (rock) formation after a well is drilled.[4]

Workover refers to any maintenance activity performed on a well that involves ceasing injection or production and removing the wellhead.[4]

Unit Conversions

1 foot (ft)	0.3048 meters (m)
1 mile (mi)	1.609 kilometers (km)
1 pound per square inch (psi)	0.006895 megapascals (MPa)
Temperature in degrees Fahrenheit (ºF)	Temperature in degrees Celsius (ºC) = (ºF – 32) × 0.56
1 pound (lb)	0.4536 kilograms (kg)
1 tonne *or* metric ton (t)	1,000 kilograms
1 megatonne (Mt)	1 x 10^6 tonnes
1 short ton *or* ton	0.9072 tonnes
1 cubic foot (ft^3)	0.0283 cubic meters (m^3)

1 Introduction

The United States Environmental Protection Agency (EPA) rulemaking *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells* [40 CFR 146.81 *et seq.*], hereafter referred to as the Class VI Rule, includes testing and monitoring requirements that are tailored to the unique circumstances of GS projects.

Testing and monitoring of GS sites is integral to the protection of underground sources of drinking water (USDWs). Testing and monitoring:

- Is required to determine whether the GS projects are operating as permitted.
- Can detect risks that may lead to the endangerment of USDWs.
- Is needed to inform reevaluation of the area of review (AoR) for Class VI projects, as required at 40 CFR 146.84(e), to ensure accurate delineation of the region surrounding the injection well(s) where the potential exists for USDWs to be endangered by the leakage of injectate and/or formation fluids.

The purpose of this guidance document is to describe the technologies, tools, and methods available to owners or operators of Class VI wells to fulfill the Class VI Rule requirements related to developing and implementing site- and project-specific strategies for testing and monitoring. The intended primary audiences of this guidance document are Class VI injection well owners or operators, contractors performing testing and monitoring activities, and UIC Program Directors.

1.1 Overview of Class VI Testing and Monitoring Requirements

The Class VI Rule requires various testing and monitoring activities to identify any risks to, and endangerment of, USDWs during the various phases of a GS project (i.e., pre-injection, injection, and post-injection) [40 CFR 146.87, 146.89, 146.90, 146.92, 146.93]. Figure 1-1 presents an example "risk diagram" for the stages of a GS project and the accompanying Class VI Rule testing and monitoring requirements that address this risk. Note that the relative risks to USDWs during different stages of a GS project are site- and project-specific; Figure 1-1 presents a simplified example for explanatory purposes.

Some of the Class VI testing and monitoring-related activities support the initial characterization of the project site and the collection of baseline data prior to the commencement of injection; these are described in the *UIC Program Class VI Well Site Characterization Guidance*. The testing and monitoring required following the cessation of injection is described in the *UIC Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure*. This document describes testing and monitoring activities that are primarily required during the injection phase.

- Injection-phase testing and monitoring activities required under the Class VI Rule include: Analysis of the carbon dioxide stream, required at a frequency that will yield information on the chemical composition and physical characteristics of the injectate [40 CFR 146.90(a)].

- Monitoring of operational parameters (injection pressure, rate, and volume, the pressure on the annulus, and the annulus fluid volume) through the use of continuous recording devices [40 CFR 146.90(b)].
- Corrosion monitoring of injection well materials, required on a quarterly basis [40 CFR 146.90(c)].
- Monitoring of ground water quality and geochemical changes above the confining zone(s), at a site-specific frequency and spatial distribution [40 CFR 146.90(d)].
- External mechanical integrity testing, at least once per year [40 CFR 146.90(e)].
- Pressure fall-off testing, at least once every five years [40 CFR 146.90(f)].
- Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) [40 CFR 146.90(g)].
- Surface air and/or soil gas monitoring, only if required by the UIC Program Director [40 CFR 146.90(h)].
- Any additional monitoring that the UIC Program Director determines to be necessary to support, upgrade, and improve computational modeling of the AoR and to determine compliance with standards under 40 CFR 144.12 [40 CFR 146.90(i)].

Owners or operators must submit, as part of the permit application, a Testing and Monitoring Plan that describes how they will meet the requirements of the Class VI Rule listed above and establishes a detailed site- and project-specific testing and monitoring strategy [40 CFR 146.90]. Further information on the Testing and Monitoring Plan is provided in Section 1.2 of this document and in the *UIC Program Class VI Well Project Plan Development Guidance*.

Additionally, the Class VI Rule includes provisions for owners or operators of Class VI wells seeking a waiver of the requirement to inject beneath the lowermost USDW [40 CFR 146.95]. These owners or operators must apply for and receive injection depth waivers and meet additional requirements to ensure the protection of USDWs above and below the permitted injection zone. The additional requirements are largely based on the need to monitor additional zones below the lower confining zone, and the Testing and Monitoring Plan that meets the requirements under 40 CFR 146.90 must also demonstrate that additional monitoring will be performed to ensure the protection of USDWs below the injection zone, per 40 CFR 146.95(a)(5). For more detailed information about the additional testing and monitoring considerations for projects operating under injection depth waivers, see the *UIC Program Class VI Well Injection Depth Waivers Guidance.*

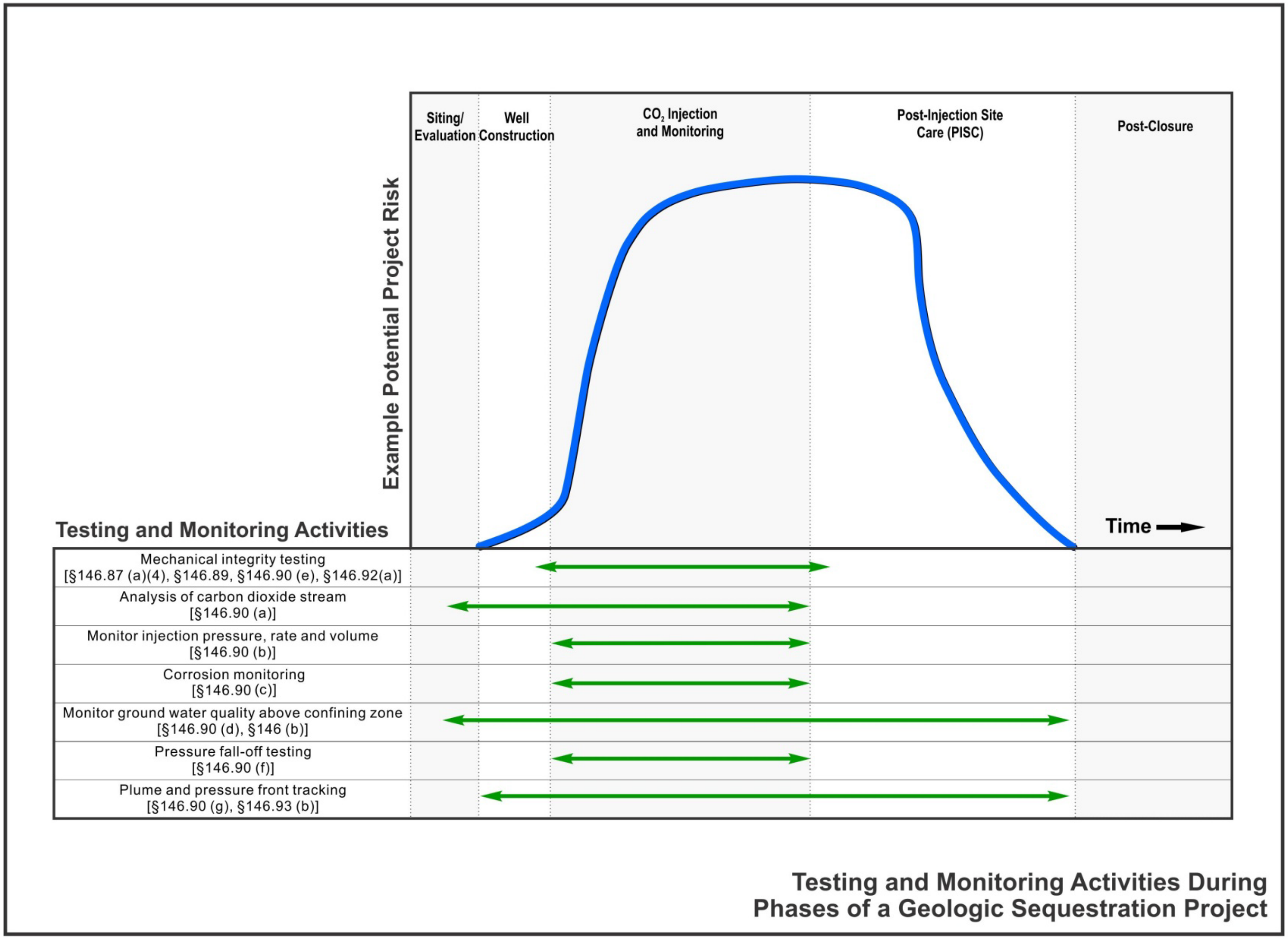

Figure 1-1. Testing and monitoring activities during different phases of a GS project in relation to potential project risk.

1.2 Testing and Monitoring Plan

The Class VI Rule, at 40 CFR 146.90, requires the owner or operator of a Class VI well to prepare, maintain, and comply with a Testing and Monitoring Plan to verify that the GS project is operating as permitted and is not endangering USDWs. This plan must be submitted with the initial permit application for approval by the UIC Program Director [40 CFR 146.82(a)(15)] and revised, if necessary, based on information collected during pre-injection logging and testing [40 CFR 146.82(c)(9)]. The plan must then be periodically reviewed, at least every five years, to incorporate monitoring data and the results of AoR reevaluations, and the owner or operator must either make necessary amendments or demonstrate that no amendments are needed [40 CFR146.90(j)].

The Testing and Monitoring Plan serves several important purposes. First, it provides an opportunity for the owner or operator to formulate an integrated strategy for monitoring the main aspects of the GS project: well integrity, operational parameters, and changes within the geologic system (plume, pressure front, and ground water quality). Importantly, Class VI permits are issued for the lifetime of the GS project, including the post-injection site care (PISC) period [40 CFR 144.36(a)]. Periodic reevaluation of the Testing and Monitoring Plan provides a vehicle for communication between the owner or operator and the UIC Program Director to ensure that, over the life of the permitted project, testing and monitoring can be modified as necessary to address changes at the GS project site. The *UIC Program Class VI Well Project Plan Development Guidance* contains additional information on the Testing and Monitoring Plan development, evaluation, and amendment process.

EPA expects that the owner or operator will work in consultation with the UIC Program Director to develop a risk-based, flexible approach for Class VI well testing and monitoring that uses appropriate technologies and techniques, based on site-specific information, to ensure protection of and to minimize risk to USDWs. The Class VI Rule provides flexibility to owners or operators to consider site-specific conditions, as described in the remainder of this document, while complying with the testing and monitoring requirements of the Class VI Rule.

The Testing and Monitoring Plan should present an effective strategy that incorporates available, site-specific techniques that support the overall goals of detecting trends or events that might lead to endangerment of USDWs and demonstrates that the project is operating as permitted. Formulating the Testing and Monitoring Plan involves an approach that includes:

1. Use of site characterization data, the site geologic conceptual model, and the results of computational modeling to identify areas or issues of potential concern for the specific GS project (e.g., possible leakage pathways, uncertainties in confining zone properties), considering the boundaries of the AoR and baseline information (where necessary).

2. Selection of testing and monitoring methods and strategies, tailored to the site-specific risk profile or identified potential concerns, to comply with the different components of the Class VI Rule testing and monitoring requirements as listed in Section 1.1.

3. Identification of site- or project-specific factors to consider or incorporate in evaluating the results of testing and monitoring, which may indicate an increase in risk to or endangerment of USDWs, and/or deviations from permitted conditions.

EPA recommends that, for each method identified in the Testing and Monitoring Plan, the owner or operator provide the following:

- A description of each method selected and its appropriateness (e.g., a geophysical method for plume tracking considering site-specific geology).
- A technical justification for the selection of the method and the associated monitoring goal (e.g., compliance with a specific Class VI Rule requirement while addressing a site-specific consideration).
- The key parameters to be tested or monitored (e.g., chemicals to analyze during ground water quality monitoring).
- Expected performance levels, limitations (e.g., detection limits), or sensitivities (e.g., geologic sensitivities of a specific geophysical method).
- The spatial or temporal strategy for application of the method or technique (e.g., a description of the monitoring well network or detailed information on the frequency of geochemical monitoring above the confining zone).
- The procedure to be used to analyze and interpret results (e.g., geophysical data processing), including levels that may indicate deviations from planned project performance (e.g., specific threshold values of monitored parameters).

Additionally, EPA recommends that information on the qualifications of contractors or vendors used for any monitoring be discussed in the Testing and Monitoring Plan, at the request of the UIC Program Director. The *UIC Program Class VI Well Project Plan Development Guidance* provides specific considerations, beyond those discussed in this document, for developing a site-specific Testing and Monitoring Plan that complies with the requirements of the Class VI Rule. Owners or operators are encouraged to refer to the *UIC Program Class VI Well Project Plan Development Guidance* for further information as they develop their Testing and Monitoring Plans.

1.2.1 Phased and/or Triggered Monitoring

Owners or operators should describe minimum monitoring techniques, locations, and/or frequencies in the Testing and Monitoring Plan. Owners or operators may also choose to establish potential conditions or situations that, if they arise during the course of the GS project, will trigger additional monitoring or adjustments to ongoing monitoring activities, and/or indicate a new phase of monitoring as planned. This type of approach would allow the site-specific testing and monitoring strategies to be tailored to any changes in predicted performance and in response to potential increased risks to USDWs as identified or detected during the course of injection. This would also ensure that monitoring is streamlined based on the availability of new information. Because a phased or triggered strategy may not be appropriate for all sites, EPA recommends that the owner or operator discuss this approach with the UIC Program Director and provide a technical justification for it in the Testing and Monitoring Plan. If phased or triggered monitoring is proposed, EPA recommends that the Testing and Monitoring Plan detail all conditions and triggers for the phasing of the monitoring activities; any planned changes in monitoring techniques, locations, and frequencies; and the planned schedule for each phase.

1.3 Organization of this Guidance

This guidance document is organized around the testing and monitoring activities that will occur during the injection phase (Figure 1-1). Following the introductory section (Section 1), the remainder of the document is organized as follows:

- Section 2, Mechanical Integrity Testing, outlines the Class VI Rule requirements related to demonstrating the mechanical integrity of the injection well. It describes the concepts of internal and external mechanical integrity and documents available mechanical integrity tests (MITs).

- Section 3, Operational Testing and Monitoring During Injection, describes other injection operation-related testing and monitoring activities, including: analysis of the carbon dioxide stream; continuous monitoring of injection rate, volume, and pressure; corrosion monitoring; and pressure fall-off testing.

- Section 4, Ground Water Quality and Geochemical Monitoring, describes the Class VI Rule requirements for geochemical monitoring above the confining zone(s). It discusses how owners or operators may design and construct a monitoring well network, collect and analyze ground water samples from above the primary confining zone, and interpret and submit the results of the ground water sample analysis.

- Section 5, Plume and Pressure-Front Tracking, describes the Class VI Rule requirements for direct and indirect monitoring of the pressure front and carbon dioxide plume. It discusses some specific direct and indirect (i.e., geophysical) monitoring technologies.

- Section 6, Surface Air and Soil Gas Monitoring, describes the Class VI Rule requirements associated with surface air and/or soil gas monitoring, including the discretion of the UIC Program Director to require such monitoring. It discusses available tools and technologies for this type of monitoring.

This guidance document also includes a number of cases studies, presented in the Appendix, which provide additional information on a range of testing and monitoring technologies used in GS projects in various settings.

The remaining sections of this guidance document discuss a wide variety of testing and monitoring techniques; many of these techniques are currently well established in the GS community and may be available for adoption based on site- and operation-specific conditions as part of the required Testing and Monitoring Plan. Additionally, this guidance document contains some references to emerging testing and monitoring methods that were not yet well established at the time this document was written. In a preliminary evaluation of GS monitoring technologies, the U.S. Department of Energy (USDOE) National Energy Technology Laboratory (NETL) assessed several technologies based on application, function, and stage of development (USDOE NETL, 2009a). In this evaluation, technologies were rated as primary, secondary, or potential in their ability to provide useful information for subsurface monitoring of injection well integrity and the fate of the injectate and mobilized fluids. Primary technologies are considered proven. Secondary technologies are considered to be currently available and appropriate for complementing the use of primary technologies in tracking of the injectate and understanding carbon dioxide behavior. Potential technologies were not yet considered mature at the time this guidance was written (they had not yet been proven in commercial-scale projects) but may have some future utility as a monitoring tool after additional field testing. It is important to note that the appropriateness of certain technologies may change in the future as their deployment increases, and this should be considered when selecting the site-specific methodologies for GS projects.

The primary technologies identified by USDOE NETL (2009a) included geophysical well logging (see the *UIC Program Class VI Well Site Characterization Guidance*), annulus pressure monitoring (Section 2), and ground water geochemistry and pressure monitoring using wells (Section 4). Of the geophysical techniques discussed in this guidance for plume and pressure-front tracking (Section 5), certain seismic methods were rated as secondary technologies and other methods were considered to be potential technologies. Emerging or experimental technologies are identified in the text, and EPA recommends that owners or operators proposing to deploy methods considered secondary or potential remain up to date on developments in those areas, technically justify the use of the methods, and discuss the appropriateness of their selection with the UIC Program Director (i.e., during the development of the Testing and Monitoring Plan).

Discussion of testing and monitoring techniques provided in this guidance is organized into four major categories of information, within each of the document sections listed above:

- General Information: How the information helps meet the requirements of the Class VI Rule, the objective of the technique, and the fundamental principles on which the technique is based.

- Application: Basic information pertaining to collection of data using the technique and references to more detailed manuals and guidance documents.

- Interpretation: The format the collected data will take and how to interpret the data to characterize the measured system.

- Reporting and Evaluation: The recommended format and required reporting frequency of collected data and interpretation, the information and data that should be included in all submittals, and the factors that the UIC Program Director may evaluate.

This document has been written to help guide owners or operators as they fulfill the testing and monitoring requirements of the Class VI Rule. Table 1-1 lists the Class VI Rule sections addressed by each of the section of this guidance document.

Table 1-1. Crosswalk of guidance document sections and relevant Class VI Rule citations.

Sections of the Testing and Monitoring Guidance	Relevant Regulatory Citations
2. Mechanical integrity testing	
2.1 Mechanical integrity definitions and mechanical integrity testing requirements	40 CFR 146.87(a)(4) 40 CFR 146.89 40 CFR 146.92(a)
2.2 Internal MITs	40 CFR 146.87(a)(4) 40 CFR 146.89(a)(1) 40 CFR 146.89(b)
2.3 External MITs	40 CFR 146.87(a)(4) 40 CFR 146.89(a)(2) 40 CFR 146.89(c) 40 CFR 146.92(a)
2.4 Reporting results of MITs	40 CFR 146.91(a)(7) 40 CFR 146.91(b)(1)
3. Operational testing and monitoring during injection	
3.1 Analysis of the carbon dioxide stream	40 CFR 146.90(a) 40 CFR 146.91(a)(1) 40 CFR 146.91(a)(7)
3.2 Continuous monitoring of injection rate and volume	40 CFR 146.88(e)(1) 40 CFR 146.90(b) 40 CFR 146.91(a)(2)
3.3 Continuous monitoring of injection pressure	40 CFR 146.88(e)(1) 40 CFR 146.90(b) 40 CFR 146.91(a)(2)
3.4 Corrosion monitoring	40 CFR 146.89(d) 40 CFR 146.90(c) 40 CFR 146.91(a)(7)
3.5 Pressure fall-off testing	40 CFR 146.90(f) 40 CFR 146.91(a)(7)
4. Ground water quality and geochemical monitoring	
4.1 Design of the monitoring well network	40 CFR 146.90(d) 40 CFR 146.90(g)(1)
4.2 Monitoring well construction	40 CFR 146.90(d)
4.3 Collection and analysis of ground water samples	40 CFR 146.90(d) 40 CFR 146.90(g)(1) 40 CFR 146.91(a)(7)
5. Plume and pressure-front tracking	
5.1 Class VI Rule requirements regarding plume and pressure-front tracking	40 CFR 146.90(g)

Sections of the Testing and Monitoring Guidance	Relevant Regulatory Citations
5.2 Direct pressure-front tracking	40 CFR 146.90(g)(1) 40 CFR 146.91(a)(7)
5.3 Plume and pressure-front tracking using indirect geophysical techniques	40 CFR 146.90(g)(2) 40 CFR 146.91(a)(7)
5.4 Use of geochemical ground water monitoring in plume tracking	40 CFR 146.90(d) 40 CFR 146.90(g)(2)
6. Surface air and soil gas monitoring	
6.1 Soil gas monitoring	40 CFR 146.90(h)(1)–(2) 40 CFR 146.91(a)(7)
6.2 Surface air monitoring	40 CFR 146.90(h)(1)–(2) 40 CFR 146.91(a)(7)

The remaining sections of this guidance document also reference complementary guidance documents that were developed concurrently with this guidance document. These additional Class VI guidance documents provide detail on additional activities that will occur during site characterization, well construction, AoR delineation, and PISC. Site characterization procedures are discussed in detail in the *UIC Program Class VI Well Site Characterization Guidance*. Recommended procedures and materials for designing and constructing injection wells that address the unique nature of carbon dioxide injection for GS are discussed in detail in the *UIC Program Class VI Well Construction Guidance.* Delineation of the AoR and performance of corrective action are covered in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*. Monitoring activities during PISC are discussed in the *UIC Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure*. As they are finalized, all of the Class VI guidance documents will be made available on EPA's website at http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm.

2 Mechanical Integrity Testing

Demonstrating and maintaining the mechanical integrity of a well is a key aspect of protecting USDWs from possible endangerment due to injection activities. It is a specific requirement for Class I, II, III, and VI wells in the UIC Program, and it may be a condition of some Class V permits. Because induced formation pressures will typically be greatest at the injection well, which penetrates USDWs, the injection zone, and intervening zones, the well is a possible conduit for fluid movement and USDW endangerment. A variety of mechanical integrity testing methods has been developed to provide information about leakage and fluid movement in and around the well and enable a determination of whether there may be leaks in the tubing, casing, or packer, or fluid flow behind the casing (through the cement sheath or in channels between the cement and the geologic formation) (e.g., USEPA Region 5, 2008). Information in this guidance document is based in large part on EPA experience and previous guidance for other UIC well classes, including guidance and technical reports prepared for the UIC program on mechanical integrity.

Mechanical integrity testing techniques may be based on a variety of principles, including acoustic and nuclear methods and temperature and pressure measurements. These methods, when selected appropriately for the site and used as part of a comprehensive Testing and Monitoring Plan, can provide complementary information about the condition of the well and alert owners or operators to well conditions that may potentially enable fluid to reach USDWs. Some mechanical integrity testing and monitoring techniques are required by the Class VI Rule (e.g., continuous annular pressure monitoring; see below), while other aspects of the mechanical integrity testing requirements afford greater flexibility, such as the choice of external mechanical integrity testing method. In all cases, owners or operators should specify in the Testing and Monitoring Plan submitted as part of a Class VI permit application the tests and equipment they intend to use, how those tests may provide complementary information, and the results from those tests that would warrant further action. The sections below outline the Class VI requirements, briefly explain internal and external mechanical integrity, and describe available MITs.

2.1 Mechanical Integrity Definitions and Mechanical Integrity Testing Requirements

MITs are required by the Class VI Rule prior to injection in a Class VI well [40 CFR 146.87(a)(4)], during the injection phase [40 CFR 146.89], and prior to well plugging after injection has ceased [40 CFR 146.92(a)]. Additionally, the UIC Program Director may require that casing inspection logs (CILs) be conducted periodically during injection [40 CFR 146.89(d)]. CILs complement MITs by providing additional information regarding any corrosion within the long-string casing and are discussed in Section 3.4.3. This section discusses the well logging and testing methods that are acceptable MITs for a Class VI well. The mechanical integrity testing methods discussed herein are standard practices in the UIC Program and are not unique to the Class VI Rule. Additional details regarding the execution of MITs can be found in USEPA Region 5 (2008), USEPA (1982), and McKinley (1994). Well service companies' technical manuals are another source of information regarding mechanical integrity testing.

As set forth in the Class VI Rule, a Class VI well has internal mechanical integrity if there is no significant leak (i.e., fluid movement) in the injection tubing, packer, or casing [40 CFR

146.89(a)(1)], and a Class VI well has external mechanical integrity if there is no significant fluid movement through channels adjacent to the injection well bore [40 CFR 146.89(a)(2)]. Figure 2-1 illustrates three scenarios in which internal or external mechanical integrity has been lost, resulting in the well being in violation of Class VI requirements:

- The top example in Figure 2-1 shows a leak in the tubing. In a properly functioning Class VI well system, the pressure will normally be higher in the annulus than in the tubing, consistent with the Class VI requirements at 40 CFR 146.88(c), unless the UIC Program Director determines that this might harm the integrity of the well or endanger USDWs. Maintaining an annulus pressure that is greater than the operating injection pressure would cause annular fluid to move into the tubing through a leak. In a situation where either the UIC Program Director has approved a lower relative annular pressure or the normal annular pressure has been lost, injectate may move from the tubing into the annulus, as shown. Any tubing leak would be considered a loss of mechanical integrity.

- In the middle example in Figure 2-1, mechanical integrity has been lost through a leak in the casing, allowing annular fluid to leak outside the casing and potentially into the formation. In cases where the formation opposite the casing leak is at a higher pressure than the annulus pressure, formation fluid could instead enter the annulus. Annular pressure is required to be monitored continuously [40 CFR 146.88(e)(1)], and shut-off systems triggered by a loss of internal mechanical integrity are required [40 CFR 146.88(e)(2)] in order to halt injection quickly and limit the amount of leakage. The shut-off system provides an additional protective barrier to USDW contamination. Failure of the shut-off system to engage, however, would permit greater movement of annular fluid or injectate, potentially endangering USDWs. This would also represent a mechanical integrity failure. Additional information about shut-off systems in Class VI wells is presented in the *UIC Program Class VI Well Construction Guidance*.

- The bottom example in Figure 2-1 illustrates loss of external mechanical integrity through channels in the cement that may allow injectate to migrate upwards and potentially reach a USDW. The goal of annual external mechanical integrity testing is to identify fluid movement through such channels. If a loss of mechanical integrity is verified, the owner or operator must take immediate action to protect USDWs [40 CFR 146.94].

Demonstrations of internal and external mechanical integrity are described in Section 2.2 and Section 2.3, respectively. A UIC Program Director may also allow the use of an alternative test if approved by the EPA Administrator, pursuant to 40 CFR 146.89(e). If a well fails an MIT (or if a loss of mechanical integrity is detected), the Class VI Rule requires that immediate action be taken by the owner or operator to remediate the well and prevent endangerment of USDWs [40 CFR 146.88(f)].

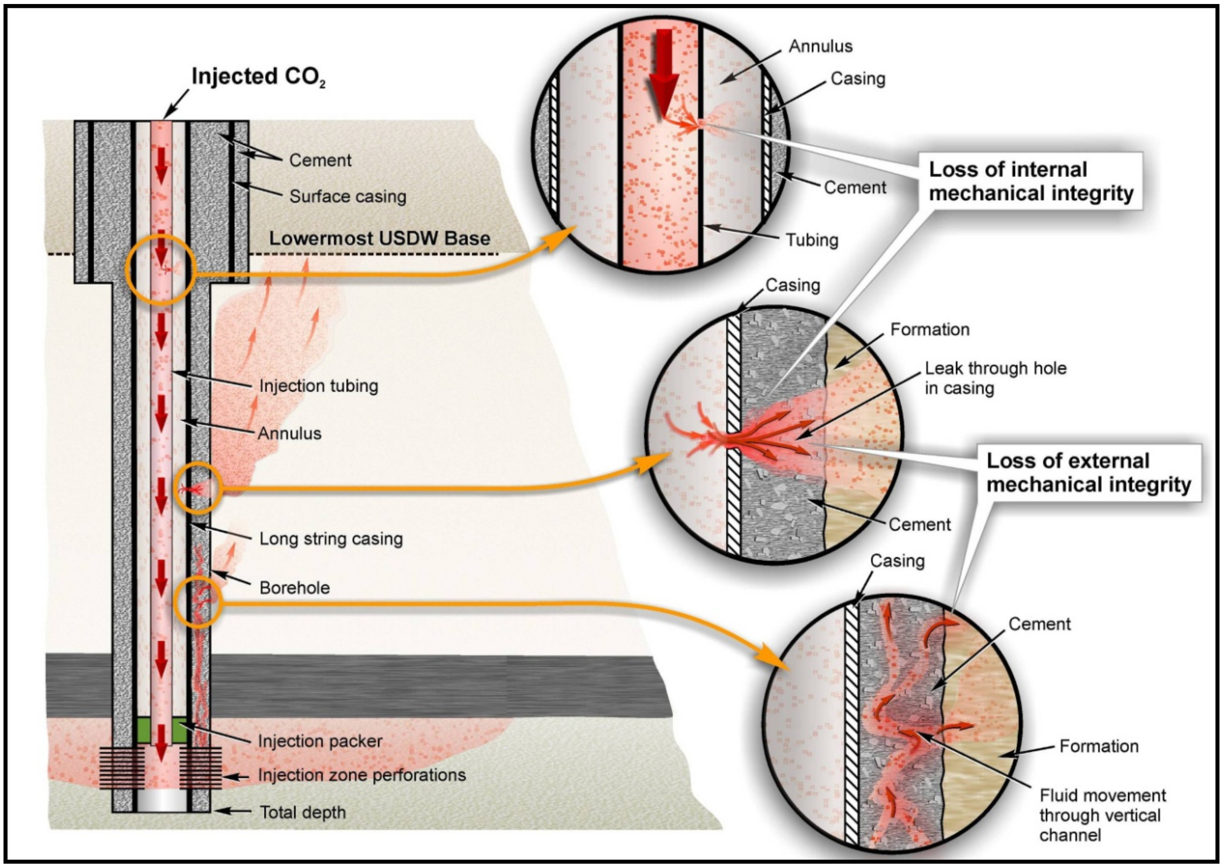

Figure 2-1. Diagram of an improperly operated injection well showing examples of loss of mechanical integrity and resulting fluid leakage (not to scale).

2.2 Internal MITs

Internal MITs are used to test for possible leaks in the casing, tubing, and packer [40 CFR 146.89(a)(1)]. The Class VI Rule requires an initial internal MIT prior to injection [40 CFR 146.87(a)(4)(i) and 146.89(b)]. Unless the UIC Program Director receives written approval from the EPA Administrator to allow an alternative test pursuant to 40 CFR 146.89(e), an annulus pressure test must be used as the initial internal MIT. The Class VI Rule also requires that owners or operators continuously monitor certain parameters to demonstrate internal mechanical integrity [40 CFR 146.89(b)]. Specifically, owners or operators must continuously monitor injection pressure, injection rate, injected volume, pressure on the annulus between the tubing and long-string casing, and annulus fluid volume, except during well workovers as defined in 40 CFR 146.88(d). Continuous monitoring of injection rate, pressure, and volume is discussed in Sections 3.2 and 3.3.

Currently, the only acceptable alternative internal MIT that is available is the radioactive tracer test, which can be used only under specific geologic conditions. EPA expects approval of the radioactive tracer test as an alternative internal MIT to be rare for Class VI wells (see Section 2.2.3). However, the radioactive tracer test may provide supplementary information to verify or further characterize loss of internal mechanical integrity.

2.2.1 Annulus Pressure Test

General Information

The standard annulus pressure test is the most common and effective means to demonstrate internal mechanical integrity within the UIC Program. It entails increasing the pressure of the annulus to a specified level, then monitoring the annular pressure for a set period of time based on established standards. The annulus pressure test is based on the principle that pressure applied to fluids filling a sealed vessel, in this case the annular space, will remain approximately constant in the absence of a fluid leak and/or significant changes in temperature. The test provides an immediate demonstration of the internal mechanical integrity of the well. If loss of internal mechanical integrity is detected by change of pressure during the test, action may be required to remediate leakage pathways in the injection tubing packer or casing prior to the commencement of injection [40 CFR 146.88(f)].

Application

The annulus pressure test is conducted after the well has been constructed and all well logs have been conducted (see the *UIC Program Class VI Well Construction Guidance*). Prior to conducting the test, the injection tubing and annulus are completely filled with liquid or gas and the temperature in the well is allowed to stabilize. The addition of any unapproved substances to the annulus liquid that might affect the outcome of the test may constitute falsification of the test procedure and invalidate the test. For the test to be effective, the pressure applied to the annulus system needs to be transmitted through the entire well bore. Therefore, no mechanical plug may be placed above the packer in a well during the annulus pressure test.

After temperature stabilization, the annulus is pressurized to the test pressure. The appropriate test pressure depends on several factors such as well depth, formation pressure, fluid density, fluid column height, and anticipated injection pressure. Casing expansion, burst pressure, and possible induced leakage or possible degradation of cement and casing should also be considered while determining a test pressure. Experience with Class II wells offers some guidance in determining appropriate test pressure; for example, regional requirements vary from 300 to 2,000 psi gauge (psig) (Nielsen and Aller, 1984). A common requirement is for the test pressure to be set based on the maximum allowable injection pressure. It should be noted that injection pressures for Class VI wells are expected to be higher than for Class II wells. For Class II wells, EPA Region 8 (1995) sets a level of the maximum allowable injection pressure or 1,000 psig, whichever is less. Another common requirement for Class II wells is for the annulus test pressure to exceed the tubing pressure by 100 to 200 psi (Texas Railroad Commission, 2006; USEPA Region 8, 1995). EPA recommends that the test pressure be determined in consultation with the UIC Program Director and be informed by previous industry/state practices in the applicable state and/or EPA region.

Following pressurization, the annular space is isolated from the source of pressure by a closed valve or by disconnecting the pressure source entirely, and any pressure changes are then measured. The appropriate test period would depend on the time that allows the pressure to stabilize. Test times typically are between 15 minutes and one hour (Nielsen and Aller, 1984). To be effective, the gauge used to measure the annular pressure should be sensitive enough to detect pressure changes that would result in a failure of the test, as determined in the Testing and Monitoring Plan. EPA recommends that the sensitivity of this method and the equipment used be discussed in the Testing and Monitoring Plan. Pressure gauge apparatuses are described in Section 3.3. During isolation, measurement of pressure is best made at regular intervals (e.g., every 10 minutes). After the test period, the volume of the recovered liquid returned from the annulus is expected to be proportional to the volume of the annulus and the amount of pressurization (USEPA Region 5, 2008).

Interpretation

Pressure measurements taken during isolation of the annulus are analyzed for any change in pressure that may indicate leakage and, therefore, failure of the test. Because the annulus exchanges heat with its surroundings, small pressure changes that are not indicative of leakage may occur during the test. Failure of the pressure to stabilize during the test period or a change above a UIC Program Director-approved minimum value indicates a failure to demonstrate mechanical integrity. A discussion of pressure changes that may indicate a failure to demonstrate mechanical integrity for a given system should be included in the Testing and Monitoring Plan.

In addition, the amount of liquid returned after the isolation period may indicate a blockage at shallow depth, and the entire well bore may not have been tested adequately. The amount of liquid to be returned in a given test can be calculated based on the size of the annulus and the test pressure (see USEPA Region 5, 2008).

2.2.2 Annulus Pressure Monitoring

General Information

The Class VI Rule requires continuous monitoring of the pressure on the annulus to verify internal mechanical integrity during the injection phase of the project [40 CFR 146.89(b)]. Significant changes in annulus pressure measured during injection may indicate a loss of internal mechanical integrity. Pressure monitoring also verifies that the annulus pressure is greater than injection pressure (within the injection tubing), which is required by the Class VI Rule unless the UIC Program Director determines that such a requirement might harm the integrity of the well or endanger USDWs [40 CFR 146.88(c)]. If the owner or operator is concerned that maintaining the greater annulus pressure would be detrimental to the well, EPA recommends that this be discussed with the UIC Program Director to find an appropriate solution. Annulus pressure monitoring to demonstrate internal mechanical integrity is performed in concert with continuous monitoring of injection pressure, rate, and annulus fluid volume, all of which are required by 40 CFR 146.89(b) to achieve this demonstration (see Sections 3.2 and 3.3).

Application

Similar to the annulus pressure test, to be effective, continuous annulus pressure measurements need to be made using a pressure gauge sensitive enough to detect pressure changes that would result in a failure of the tests. It must also be considered that a pressure gauge at the surface will require knowledge of temperature and density of the fluid in order to determine pressures down-hole. Pressure gauge apparatuses are described in Section 3.3.

Interpretation

Figure 2-2 presents a flow chart explaining the interpretation of the results of annulus pressure monitoring. Continuous monitoring of the annulus is similar in methodology to the initial pressure test, in that both methods involve monitoring annular pressure to detect unexpected changes that may indicate fluid leakage. However, interpretation of continuous annular pressure monitoring data is complicated by operational effects such as injection tubing expansion or contraction, well bore temperature changes, changes in injection rate or temporary cessation of injection, and changes in the injectate temperature. In the event of a casing leak opposite a permeable zone, the pressure will normally fall to atmospheric pressure; if not, the range of pressure change will be much diminished because the aquifer in communication with the leak will buffer volumetric changes in the annulus. In the event of a tubing or packer leak, the annulus pressure will track injection pressure. These two pressures will probably not be equal because of a pressure loss due to friction in the injection tubing and density differences.

A leak that does not result in an unimpeded pressure change might not be apparent. Therefore, to enhance the value of maintaining a positive pressure differential and the likelihood of detecting a leak, the Class VI Rule requires owners or operators to monitor and report the volume of liquid additions to the annulus system [40 CFR 146.91(a)(6)]. The results of these measurements are accumulated, and a continuing need to add or remove fluid to maintain a set pressure may be evidence of a leak in the well.

The standard used for evaluating continuous pressure measurement is typically similar to the minimum value used during the annulus pressure test (USEPA Region 5, 2008). Minimum threshold pressure changes that may indicate a loss of mechanical integrity are expected to be identified in the Testing and Monitoring Plan by the owner or operator and approved by the UIC Program Director. However, it may only be possible to apply the pre-determined minimum pressure change standard when external factors that might affect the annulus pressure are stable. Otherwise, liquid property changes occurring in response to changes in ambient conditions may make determination of a leak-induced pressure change impossible. To provide an effective, real-time demonstration of internal mechanical integrity, frequent review of pressure records is necessary. This review would focus on the pressure in the annulus relative to atmospheric pressure, injection pressure as measured at the surface, and pressure in formations adjacent to the well bore.

Continual addition or removal of fluids to maintain annular pressure or annular pressure changes greater than the UIC Program Director-approved minimum change that cannot be explained by changing operational conditions (e.g., injection rate, pressure, or temperature) may indicate a possible loss of internal mechanical integrity. Under these circumstances, EPA recommends ceasing injection and conducting an annulus pressure test (Section 2.2.1). A radioactive tracer survey may also be conducted to determine the depth or location of the leak (Section 2.2.3). If the annulus pressure test indicates no loss of internal mechanical integrity, injection may resume. If a loss of mechanical integrity is identified, the Class VI Rule requires that the owner or operator cease injection and take appropriate action to repair the well and investigate any potential impairment of a USDW [40 CFR 146.88(f)].

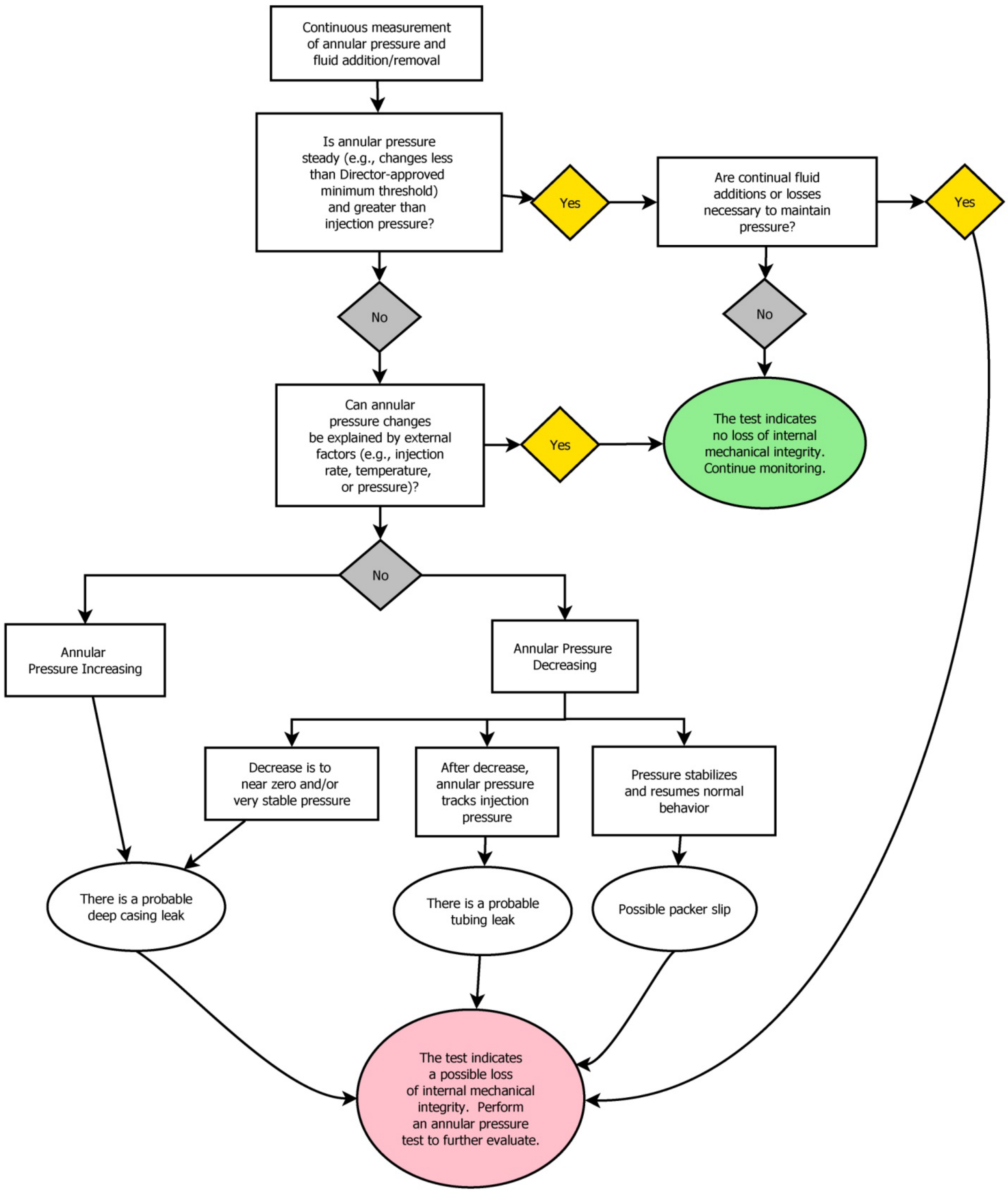

Figure 2-2. Interpretation of annulus pressure monitoring for a typical injection well.

2.2.3 Radioactive Tracer Survey

General Information

The Class VI Rule requires annulus pressure tests and monitoring to verify internal mechanical integrity. However, if written approval is received from the EPA Administrator, the UIC Program Director may allow alternative mechanical integrity testing methods [40 CFR 146.89(e)]. Currently, the only available alternative internal MIT is the radioactive tracer survey, which is used under specific conditions (USEPA, 1987b). EPA expects that approval of the radioactive tracer survey as an alternative internal MIT will be rare. The radioactive tracer survey may require long periods of investigation and cannot feasibly be conducted continuously during injection (and therefore cannot be used to comply with the continuous monitoring requirements). However, the radioactive tracer survey provides supplementary information regarding internal fluid leakage and therefore may be conducted in addition to annular pressure monitoring. Importantly, the radioactive tracer survey may be used to locate the depth of a leak within the well bore, unlike annulus pressure tests. As discussed in Section 2.3.4, in very specific circumstances, radioactive tracer surveys may also be used as an external MIT.

Application

The radioactive tracer survey uses a wireline tool that consists of an injector stage, one or more gamma radiation detector devices, and a collar locator (i.e., a logging tool used to detect the threaded collar used to connect two joints of casing). The purpose of the collar locator is to pinpoint the location of leaks in reference to permanent markers. This may also be done by means of correlation to a gamma ray log that is scaled to show lithologic effects (see the *UIC Program Class VI Well Site Characterization Guidance*). Using a collar locator lets the analyst know immediately whether an identified leak is at a collar, while using a gamma ray correlation log clarifies the stratigraphic location of the leak. An anionic tracer material, such as iodine-131, should be used to minimize molecular attraction to well and rock materials. The radioactive tracer is usually iodine-131 because of its short (eight-day) half-life

A radioactive tracer survey may include more than one type of test (slug tracking or velocity shot; see McKinley, 1994) and it involves releasing the radioactive tracer into the tubing above the interval to be tested and subsequently measuring gamma radiation as it moves through the well. In the slug test, a slug of tracer is released and the tool is lowered up and down the well repeatedly while the position of the slug(s) is tracked. In the velocity shot method, the detectors remain stationary and monitor the time at which the slug passes. The relative positions of the injector and stationary detectors are variable. Three detectors are sometimes used, with two below the injector. This allows for very accurate measurement of the speed of the injectate and simplifies location of the upward limit of leakage by eliminating some repositioning of the tool. Radioactive tracer surveys can be effective for locating leaks in both the tubing and the casing; McKinley (1994) provides an example calculation showing an evaluation for both tubing and casing leakage using data from several runs. Testing is commonly conducted during injection of carbon dioxide and it.is best to maintain an injection rate as close to the project's maximum injection rate as practical. See USEPA Region 5 (2008) for detailed instructions on conducting a radioactive tracer survey as an internal MIT.

Interpretation

After a slug of radioactive material is injected, that slug will move with the injectate into the injection zone. If a measureable leak is present, the gamma ray detector will identify an area of increased radioactivity after the slug has passed. Importantly, to distinguish the impact of lithologic features, the gamma ray log needs to be compared to a baseline log that was run before injection commenced (see the *UIC Program Class VI Well Site Characterization Guidance*). Figure 2-3 presents an example radioactive tracer survey log conducted to test leakage through casing; in this example, the tubing has been removed, further facilitating the determination of leakage through and flow behind the casing. If, compared to the baseline gamma ray log, no additional radiation is observed after the slug has passed, the well has demonstrated internal mechanical integrity at the depth tested.

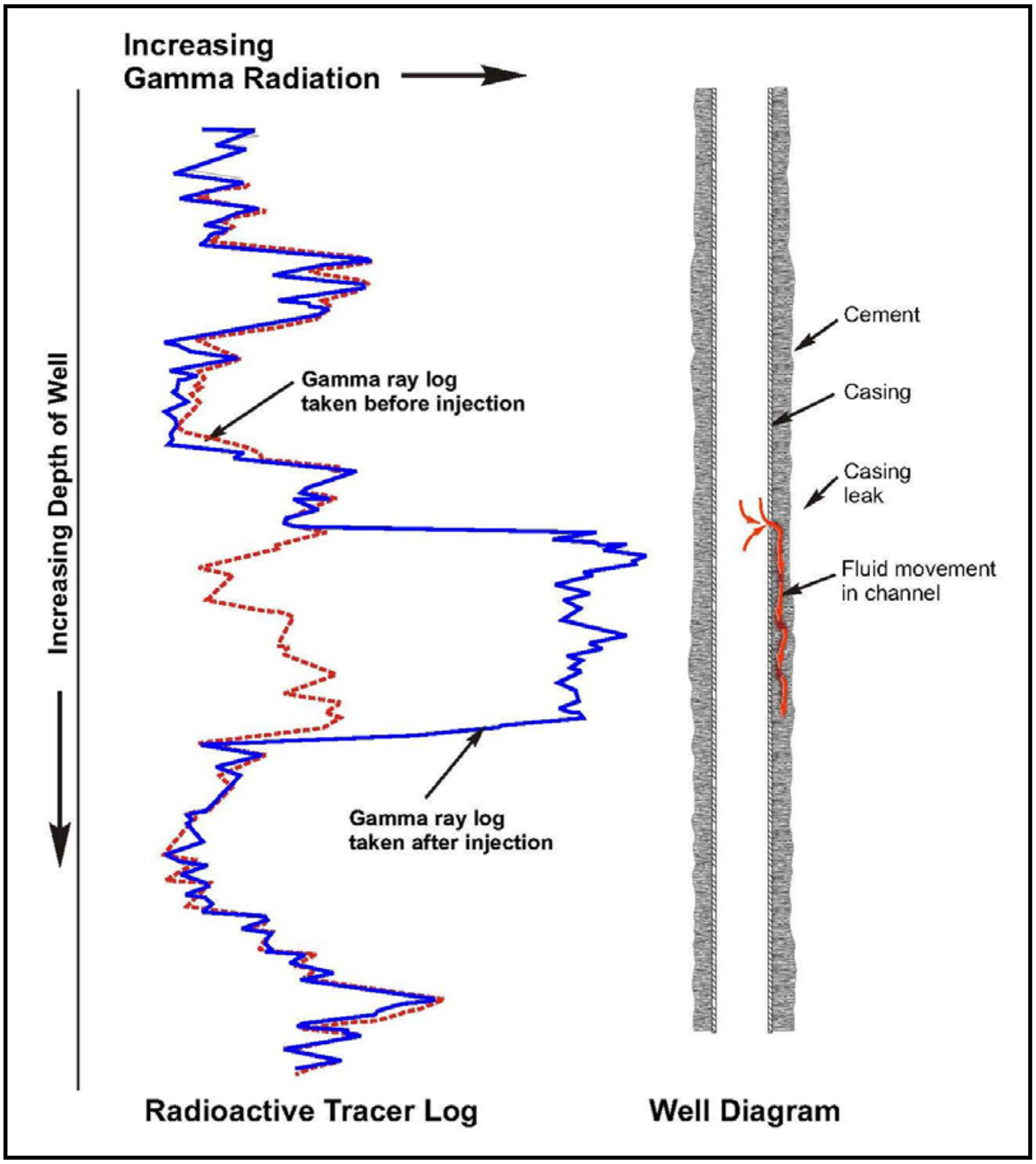

Figure 2-3. Radioactive tracer log showing the detection of a leak in the casing and subsequent fluid movement in a channel behind the casing (USEPA, 1982; not to scale).

2.3 External MITs

As defined in the Class VI Rule, external mechanical integrity refers to the absence of any significant fluid movement into a USDW through channels adjacent to the well bore [40 CFR 146.89(a)(2)]. External mechanical integrity testing methods and technologies are designed to detect fluid movement behind the casing that might result in movement of fluid into a USDW. The Class VI Rule requires that an external MIT be conducted prior to injection [40 CFR 146.87(a)(4)], at least once per year until the injection well is plugged [40 CFR 146.89(c); 40 CFR 146.90(e)], and prior to injection well plugging after the cessation of injection [40 CFR 146.92(a)]. The UIC Program Director may also require additional tests [40 CFR 146.89(e)]. If a loss of external mechanical integrity is detected, the Class VI Rule requires that immediate action be taken by the owner or operator to remediate the well and prevent endangerment of USDWs [40 CFR 146.88(f)].

Unless the UIC Program Director receives written approval from the EPA Administrator to allow an alternative test [40 CFR 146.89(e)], the owner or operator must use at least one of the following methods for external mechanical integrity testing: an oxygen activation log, temperature log, or noise log [40 CFR 146.89(c)]. The choice of MIT(s) to use depends on conditions of the site and well, and operator preference. As described below, the separate MITs provide complementary, but not entirely duplicative, information regarding the well. In cases where one test indicates the potential loss of mechanical integrity, follow-up tests can verify and further characterize the potential leakage pathway. Changes in injection pressure (see Section 3.3) or annular pressure(s) (see Section 2.2) are typically the first indication of a loss of mechanical integrity, and information from operational pressure monitoring may inform and complement the tests listed in this section.

2.3.1 Oxygen Activation Log

General Information

The oxygen activation method is based on the ability of a wireline tool to activate oxygen into nitrogen-16 (N^{16}) within a short distance. This is accomplished by emitting high-energy neutrons from a neutron source. N^{16} is an unstable isotope of nitrogen that is referred to as activated oxygen. The N^{16} produced undergoes beta decay with a half-life of 7.1 seconds, with 69 percent of the beta decay path accompanied by gamma radiation. The high-energy gamma ray easily penetrates the casing, cement, tubing, and fluids in the well and can be measured by detectors in the borehole (Bernard, 1995). The detectors are typically located at different distances from the neutron source. The N^{16} generated from oxygen in the water serves as a water tracer. The velocity of the water moving in a channel is estimated by timing the change in gamma radiation between multiple detectors that are apart at known distances. The direction of flow can also be assessed by positioning detectors below or above the generator (Bernard, 1995). Studies under controlled conditions have shown that water velocities between two and 120 feet per minute can be measured.

The results of oxygen activation logs are relatively simple to interpret. Compared to temperature logs (Section 2.3.2), little or no shut-in (i.e., temporary cessation of injection) time is necessary. The test also does not require a liquid-filled well bore. One disadvantage of this method is that it detects flow in a broad, but fixed, velocity range. The method also has a very small range of investigation and cannot be used to demonstrate the absence of liquid movement through confining layers (USEPA Region 5, 2008). EPA recommends that the owner or operator demonstrate to the UIC Program Director that the tool is calibrated and used in a manner that allows for the detection of the flow of gaseous, liquid, and/or supercritical carbon dioxide.

Application

The wireline logging tool consists of a high-energy neutron generator and multiple gamma ray detectors. By spacing several detectors at increasing distances from the oxygen activation area, interpretational accuracy is increased. Although the activated oxygen may be present in water potentially moving along the well bore, activation of oxygen-bearing materials in the well may give rise to a level of background radiation that needs to be accounted for in order to obtain a valid measurement of the movement of fluid passing along the well bore. Therefore, the activity due to the flowing water will need to be corrected for the stationary signal generated by activation of oxygen-bearing well materials when there is no flow and for the normal instrumental gamma background in the borehole (Bernard, 1995). This is normally achieved by calibrating the instrument for the stationary signal and for the instrumental background in the part of the well where there is no flow behind the casing. Alternatively, in applicable cases, extending the measurement period at each station to the time beyond which the activated oxygen in flowing water has been transported away might also allow for correction of the background signal. The rate of decay indicated by the late measurements or in the representative section of the well bore is used to calculate the theoretical levels of gamma radiation that would be measured if there were no water movement. The difference between the calculated and measured values is assumed to be the effect of the decay of activated oxygen carried to the vicinity of the detectors as part of moving water. However, it is important to note that background measurements made at different locations and different times may not always represent the actual background at the time of this test, which may lead to some error in evaluating the flow (Bernard, 1995).

To be effective, injection pressure needs to be maintained during the test to ensure identification of fluid flow near the injection zone. The activation times used depend upon the water flow rate and the positions of the detectors. While a long activation provides high signal strength, it might also lead to losing part of or the entire signal, particularly at high water velocities. EPA recommends that appropriate parameter values for the specific well conditions be discussed in the Testing and Monitoring Plan. EPA also recommends that all measurements be taken for periods of time sufficient for the well-specific conditions, with the well injecting at the maximum normal rate. If anomalies are found, additional readings made above and below the depth of the anomaly will confirm the anomalous reading and discover the extent of fluid movement.

Interpretation

Measurements from two or more gamma-ray detectors may be used to calculate water flow direction and velocity. If water flow outside of the casing is detected, this indicates the potential loss of external mechanical integrity. A specific threshold velocity, below which the measured water flow velocities would indicate false positives based on project-specific conditions, should be described in the Testing and Monitoring Plan. To minimize false positives, it is recommended that all measurements be confirmed at several nearby depths and/or that measurements be taken under a minimum of three varying injection rates: 75 percent, 50 percent, and 25 percent of the maximum permitted injection rate. If a failure of an external MIT occurs, the Class VI Rule requires that the owner or operator notify the UIC Program Director within 24 hours [40 CFR 146.91(c)(4)].

2.3.2 Temperature Log

General Information

Temperature logging is based on the principle that fluid leaking from the well will cause a temperature anomaly adjacent to the well bore. Temperature logs are run after the well has been shut-in (i.e., when injection is not occurring) to allow for temperature equilibration and after heat radiation from well cement hydration has ended. The Class VI Rule requires that temperature logs be conducted immediately after well cementing to evaluate the presence of cement behind the casings [40 CFR 146.87(a)(2)(ii) and 146.87(a)(3)(ii)] (see the *UIC Program Class VI Well Construction Guidance*). If temperature logs are to be used for external mechanical integrity testing, several logs will be run prior to injection to comply with both cement evaluation and external mechanical integrity testing requirements.

Fluid that leaks from the well bore will, in most cases, be of a different temperature compared to native fluids at a given depth. Given sensors of sufficient sensitivity, it is possible to identify the change in temperature resulting from heating or cooling by leaking fluid. Therefore, temperature logs may also confirm that there is no flow of injectate through the rock surrounding the well bore. In addition, it is possible to identify the source of the leaking fluid if flow is continuing where small casing leaks occur.

To demonstrate mechanical integrity with a temperature log, the well needs to be shut-in long enough for temperature effects to dissipate, leaving a relatively simple temperature profile. Experience has shown that 36 hours is usually a sufficient shut-in period (USEPA Region 5, 2008). During the shut-in period, the temperature within the well bore will typically change toward static geothermal conditions. If there has been a leak of fluid out of the well, the temperature within the well bore at this location will change to a lesser degree and be measured as an anomaly because the temperature of the surrounding formation will have been modified by the leaking fluid (Figure 2-4). In particular, leaking fluid may introduce a cooling effect if it decompresses.

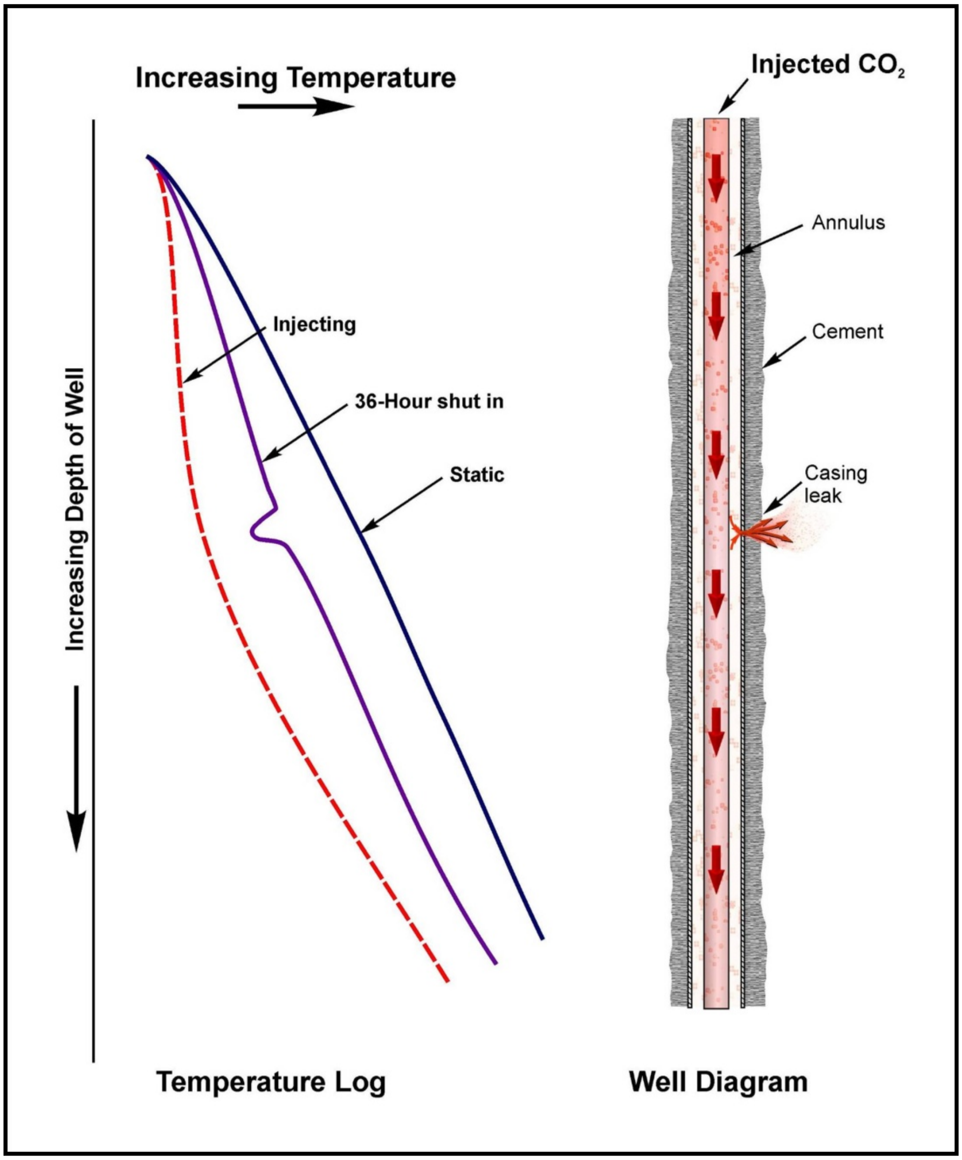

Figure 2-4. Temperature log showing the detection of a leak in the casing (USEPA, 1982; not to scale).

Application

In new wells, EPA recommends that baseline temperature logs to demonstrate external mechanical integrity be performed as long as possible after the drilling of the well, but before injection begins (see the *UIC Program Class VI Well Site Characterization Guidance*). Temperature effects due to circulation and infiltration of drilling fluid will persist for several weeks or months after drilling is completed. Although these anomalies can mark permeable zones, the existence of a temperature log that reflects the natural geothermal gradient can be of great value in evaluating later analyses and for understanding other geophysical effects.

The wireline temperature logging tool consists of circuitry that responds to temperature change by changing resistance to current flow. The response is linear, and temperature logs can distinguish very small changes in temperature. To be effective, temperature logging tools should have good thermal coupling to the borehole environment, which means that they are generally not useful in gas-filled holes. Emerging temperature measurement technologies, such as the use of fiber optic cables, may be more applicable to carbon dioxide-filled wells. During logging, sampling is done at short intervals as the tool is lowered into the well, producing a record of the entire well bore. Because the tool does not react to temperature change instantaneously and is continuously moving, the measured temperature changes lag behind actual well bore temperature changes by a consistent amount. The more slowly the tool moves, the closer the measured temperatures are to actual temperatures.

If there are frequent changes in the temperature of the injectate or if process changes have caused a significant change in the temperature of the injectate, it is important to record the average temperatures of the injectate before existing logs were made, as well as the date of the change in injectate temperature and the volume of liquid injected before and since that time. The scaling of logs is very important. Features of significance are emphasized by compressing the depth scale and expanding the temperature scale. A depth scale of one or two inches per 100 feet and a temperature scale of one inch to two degrees Fahrenheit are appropriate in almost every case. If multiple logs are run while the well is shut-in, it is helpful to display them on the same axes (depth scale) for comparison. Gamma ray logs may be run simultaneously with the temperature log. Gamma ray logs provide depth control and important information about the rock types along the well bore. Additional detailed instructions for conducting temperature logs for external mechanical integrity testing are available in USEPA Region 5 (2008).

Interpretation

EPA recommends that the temperature log be compared to a baseline log taken prior to injection or to other logs taken at the same site. After the temperature effects caused by casing joints, packers, well diameter, casing string differences, and cement have dissipated, the temperature profiles are expected to be similar, although not identical. If the thermal effects of construction features are evident in the temperature log, a longer shut-in period may be needed.

Identification of flow is based on relative differences between the collected temperature log and the baseline log or the logs of nearby wells, if such logs exist. Although the gradients may be quite different as a result of differing injection history, their profiles should be consistent. Lithologic effects that appear on one log are expected to appear similarly in other wells at the same site. Anomalies are revealed by inconsistencies among logs made at the same site under conditions that should result in thermal stability. If there are no logs suitable for comparison, then deviations from a predictable geothermal gradient, modified by the effects of injection, indicate anomalies.

When more than one log is run sequentially in the same well, temperature anomalies are likely to become more prominent as the profile returns toward the natural geothermal gradient. An example temperature log, showing an anomaly indicative of leakage, is shown in Figure 2-4. Anomalies may indicate a failure of mechanical integrity. In such a case, an additional log may be necessary to show whether forms apparent on the original log are evolving toward the forms established on the log from another well. Comparison of these two new logs is expected to show increasing similarity along the cased well bore; if not, then there may be flow along a channel adjacent to the well bore. In the event that there are unresolved anomalies that might indicate the absence of mechanical integrity, another approved method could be used to confirm the absence of flow into or between USDWs. Depending on the nature of the fluid movement, radioactive tracer, noise, oxygen activation, or other logs approved by the UIC Program Director may be used to further define the nature of the fluid movement. For more information, see the detailed description of temperature logging provided by McKinley (1994).

2.3.3 Noise Log

General Information

Channels in cements along well bores are very rarely uniform. When flow is occurring through these channels, irregularities in channel cross section usually result in the generation of some turbulence, which occurs in audible ranges. Sonic energy travels for considerable distances through solids, allowing sensitive microphones to detect the effects of turbulent fluid flow at sizeable distances. In addition, different types of turbulence result in sounds with different frequencies. Single-phase turbulence results in low-frequency sounds, while two-phase turbulence usually results in high-frequency sounds. High pass filters are used to determine the intensity of noise detected within various frequency ranges.

Application

Noise logging tools are wireline tools that are essentially very sensitive microphones. Sampling is done in a stationary mode, and the time required at each station is approximately three to five minutes. Detected sounds are transmitted to recorders that measure the amount (loudness) of sonic energy received over a period of time. A cumulative measure of the sound energy that has been received is recorded. Because sonic energy travels for considerable distances through solids, sampling can be done in a reconnaissance mode, with additional stations run where increases in energy are detected to identify the exact locations of conditions that cause sonic events. Similarly to temperature logs, sonic logs are more effective in liquid-filled holes because of improved coupling.

Noise logging may be carried out while injection is occurring in many wells because flow restriction caused by the logging tool is often insufficient to cause turbulence and detectable noise. It is especially desirable to log while injecting when looking for flow resulting from pressure increases near the top of the injection zone. EPA recommends that noise measurements be made at intervals of 100 feet to create a log on a coarse grid. If any anomalies are evident on the coarse log, EPA recommends constructing a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels. EPA also recommends that noise measurements be made at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within 100 feet above that zone, at the base of the lowermost USDW, and, in the case of varying water quality within the zone of USDWs, at the top and base of each interval with significantly different water quality from the next interval. Additional measurements may be made to pinpoint the depths at which noise is produced.

Interpretation

When the level of sound is low, a linear scale is used for reporting noise logs, and, when there are intervals with higher sound, a logarithmic scale is used. Regardless of whether data are presented in linear or log form, a vertical scale of one or two inches per 100 feet is recommended. Noise logging is commonly used in other classes of injection wells, and the interpretation of noise logs is well established. Departures from baseline noise levels in the log indicate an anomaly. Therefore, it is important to collect adequate baseline data to understand normal fluctuations during operation and to be able to identify what constitutes a significant departure from baseline. Figure 2-5 shows a noise log indicating leakage through a cement channel adjacent to the well bore. Ambient noise while injecting that produces a signal greater than 10 millivolts (mV) may indicate leakage and potential loss of external mechanical integrity. If a lack of external mechanical integrity is identified, the Class VI Rule requires that action be taken to remediate the well [40 CFR 146.88(f)]. If the log measurements are ambiguous, another testing method may be used for confirmation.

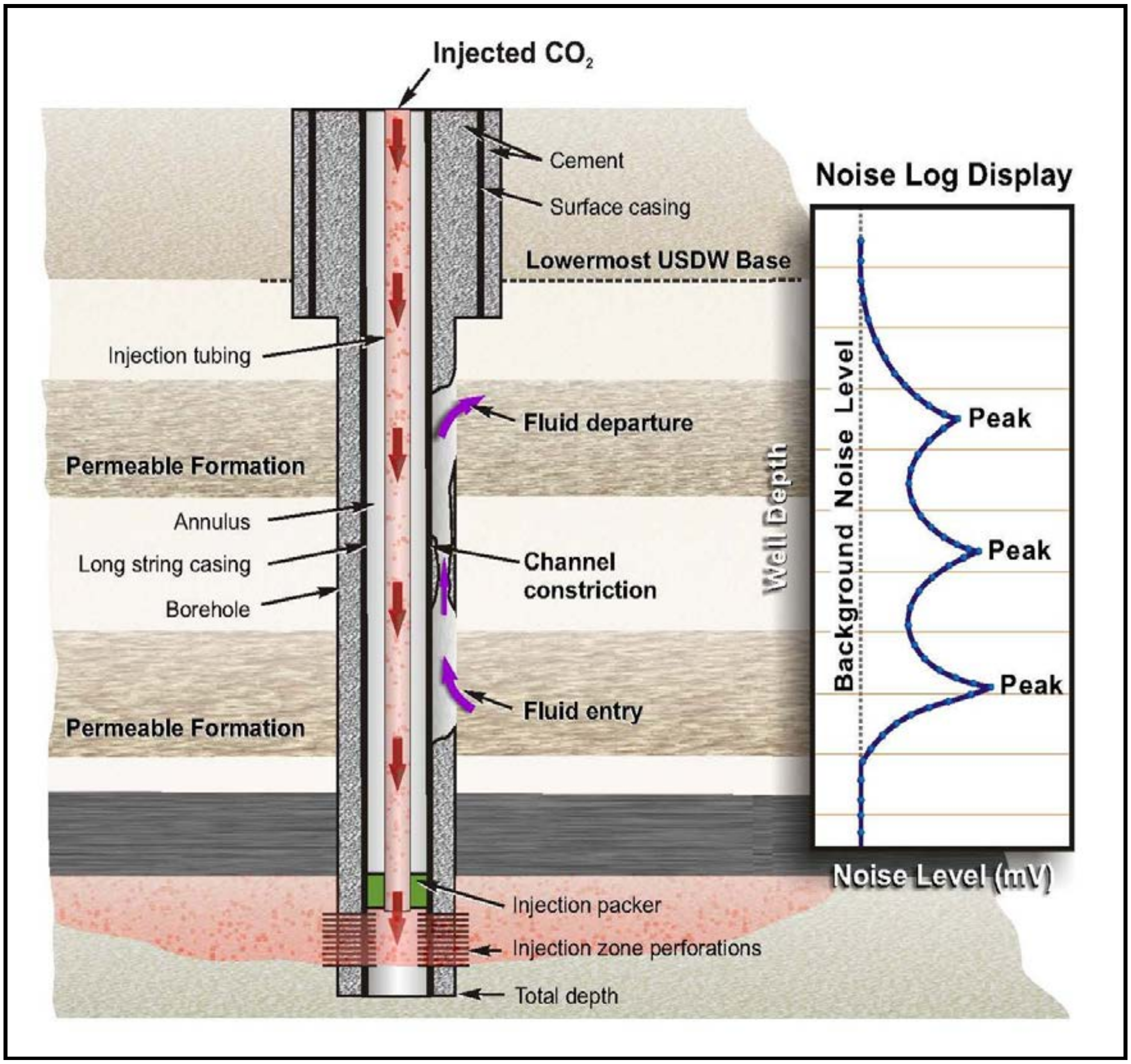

Figure 2-5. Diagram of fluid leakage through channel in cement and corresponding noise log (not to scale). Note that this hypothetical schematic represents an injection well that likely is operating outside of permit conditions, due to the large areas with no or little cement.

2.3.4 Alternative Methods for External Mechanical Integrity Testing

The Class VI Rule requires that an oxygen-activation log or other tracer survey, a temperature log, or a noise log be conducted to comply with external mechanical integrity testing requirements [40 CFR 146.89(c)]. However, alternative methods beyond those listed may be allowed by the UIC Program Director if written approval is received from the EPA Administrator [40 CFR 146.89(e)]. A request to use methods other than those currently approved by EPA requires this additional EPA approval process and publication of the alternative method's approval in the *Federal Register*, as required at 40 CFR 146.89(e). Currently, there are no alternative methods that may feasibly be used for external mechanical integrity testing beyond those listed here, except under very limited circumstances. The Class VI Rule does not preclude the use of methods that may be developed in the future, as long as use of these methods is approved by the EPA Administrator following the procedure in 40 CFR 146.89(e).

Radioactive tracer surveys have been used for assessing external mechanical integrity and can be very sensitive. Radioactive tracer survey instrumentation and basic methods for external MITs are the same as those used for internal mechanical integrity testing (as described in Section 2.2.3). McKinley (1994) provides information on radioactive tracer tests and their interpretation, including how to discern fluid movement behind the well.

By regulation, use of radioactive tracer surveys as the sole test for external mechanical integrity testing is limited to cases where there are no permeable formations between the injection zone and the lowermost USDW (USEPA, 1987b). Essentially, a single confining layer would need to be present that separates the injection zone from the lowermost USDW. Given the depths of Class VI wells and the significant siting requirements, it is unlikely that this condition will be met for Class VI wells. However, radioactive tracer tests may be used to complement the external MITs discussed above.

Additional external MITs include evaluation of cementing records and cement evaluation tools (see the *UIC Program Class VI Well Construction Guidance*), both of which have previously been used in isolated circumstances for external mechanical integrity testing. These methods, however, do not directly detect fluid leakage and do not identify any potential leakage pathways in the cement. Therefore, the use of cement evaluation tools and cementing records is not acceptable as the sole basis for demonstrating external mechanical integrity of Class VI wells.

2.4 Reporting the Results of MITs

The Class VI Rule requires that the owner or operator submit a descriptive report of all required MITs conducted at the site to EPA in an electronic format [40 CFR 146.91(e)]. The results of initial MITs, performed prior to injection, must be submitted to the UIC Program Director prior to the commencement of injection [40 CFR 146.82(c)(8)]. The results of continual monitoring to demonstrate internal mechanical integrity must be submitted in the required semi-annual operational reports [40 CFR 146.91(a)]. Any failure to maintain mechanical integrity must be reported to the UIC Program Director within 24 hours [40 CFR 146.91(c)], and all results of periodic MITs must be reported within 30 days of testing, regardless of the results [40 CFR 146.91(b)].

When reporting the results of MITs, it is recommended that the submittal to the UIC Program Director include:

- Chart and/or tabular results of each log or test.
- The interpretation of log results provided by the log analyst(s).
- Description of all tests and methods used.
- Records and schematics of all instrumentation used for the test(s) and the most recent calibration of any instrumentation.
- Identification of any loss of mechanical integrity, evidence of fluid leakage, and remedial action taken.
- The date and time of each test.
- The name of the logging company and log analyst(s).
- For any tests conducted during injection, operating conditions during measurement, including injection rate, pressure, and temperature (for tests run during well shut-in, this information should be provided relevant to the period prior to shut-in).
- For any tests conducted during shut-in, the date and time of the cessation of injection and records of well stabilization.

The UIC Program Director will evaluate the results and interpretations of MITs to independently assess the integrity of the injection well.

3 Operational Testing and Monitoring During Injection

The Class VI Rule requires owners or operators of Class VI wells to monitor injectate properties, injection rate, pressure, and volume, and corrosion of well materials, and perform pressure fall-off testing [40 CFR 146.90(a), (b), (c), and (f)]. Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics is required under the Class VI Rule [40 CFR 146.90(a)]. Analysis of the carbon dioxide stream is also required prior to commencing injection [40 CFR 146.82(a)(7)(iv)]. This analysis will identify the constituents of the carbon dioxide stream, including impurities that might alter the corrosivity or other properties of the injectate downhole. Such information is necessary to inform well construction and the project-specific Testing and Monitoring Plan. Information on the composition of the injectate will also support considerations regarding the reactivity of the injectate with the subsurface matrix and formation fluids; these considerations may be used in the computational modeling for AoR delineation. The details of the injectate sampling process and the frequency of sampling and analysis, along with a description of how the results may indicate deviation from planned project operations, will be described in the UIC Program Director-approved, site- and project-specific Testing and Monitoring Plan.

The Class VI Rule requires the installation and use of continuous recording devices to monitor injection rate, volume, and pressure [40 CFR 146.88(e) and 146.90(b)]. This information is used to verify compliance with Class VI permit conditions and to inform AoR reevaluations. Additionally, anomalies in injection rate and/or pressure may be an indicator of deviation from planned operations due to field conditions or leakage from the authorized zone. EPA recommends that the Testing and Monitoring Plan include a discussion of expected variations in these parameters and how the proposed strategy will detect any problematic deviations in project performance.

Owners or operators of Class VI wells are required to conduct a pressure fall-off test at least once every five years [40 CFR 146.90(f)]. Pressure fall-off tests can indicate whether reservoir pressures are consistent with predictions. Results of these tests will inform and verify site characterization information and AoR reevaluations, and confirm that the project is operating properly and that the injection zone is responding as predicted. EPA recommends that the frequency of pressure fall-off testing be established in the Testing and Monitoring Plan.

This section discusses how owners or operator may conduct operational monitoring activities performed during the injection phase.

3.1 Analysis of the Carbon Dioxide Stream

The Class VI Rule requires that the injected carbon dioxide stream be analyzed with sufficient frequency to yield data representative of its chemical and physical characteristics [40 CFR 146.90(a)]. These characteristics include fluid composition (i.e., fraction of carbon dioxide and other constituents measured on a volumetric or mass basis at a known temperature and pressure), temperature, and pressure, as well as additional parameters that may be used for understanding potential interactions between the injectate and the formation.

The primary purpose of analyzing the carbon dioxide stream is to evaluate the potential interactions of carbon dioxide and/or other constituents of the injectate with formation solids and fluids. This analysis can also identify (or rule out) potential interactions with well materials. Establishing the chemical composition of the injectate also supports the determination of whether the injectate meets the qualifications of hazardous waste under the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 *et seq.* (1976), and/or the Comprehensive Environmental Response, Compensation, and Liability Act, (CERCLA) 42 U.S.C. 9601 *et seq.* (1980). Additionally, monitoring the chemical and physical characteristics of the carbon dioxide (e.g., isotopic signature, other constituents) may help distinguish the injectate from the native fluids and gases in case of a leak. Injectate monitoring is required at a sufficient frequency to detect changes to any physical and chemical properties that may result in a deviation from the permitted specifications.

This section discusses the analysis of the carbon dioxide stream, which may include constituents other than carbon dioxide, such as sulfur dioxide, hydrogen sulfide, nitrogen oxides, hydrocarbons, carbon monoxide, methane, water vapor, nitrogen, oxygen, mercury, or arsenic (Apps, 2006). Owners or operators may investigate adapting methods from those available for flue gas analysis in industrial settings as well as analytical methods for verification of the purity of carbon dioxide used for supercritical fluid applications or the food industry.

Chemical analysis of carbon dioxide and potential trace constituents for non-GS applications (i.e., flue gas and food-grade carbon dioxide) is typically performed in the gas phase. Because carbon dioxide for GS will in most cases be transported and injected in the supercritical phase, samples may need to be extracted from the pipeline or wellhead via a valve and permitted to decompress into a gaseous phase within a sample holder or other device for analysis by one of the methods described below. If samples are allowed to decompress to the gas phase for chemical analysis, temperature and pressure will both drop and will no longer represent conditions in the pipeline or as injected. Therefore, EPA recommends that, if possible, the temperature and pressure measurements represent the in situ conditions at the injection point. Alternatively, samples may be allowed to decompress prior to analysis and standard methods may be used to calculate chemical and physical properties at in situ pressure and temperature from the results of analysis of the decompressed samples.

Owners or operators are encouraged to consult with the UIC Program Director to establish a carbon dioxide stream characterization protocol that is tailored to the specifics of the GS project. EPA recommends that the methods used to characterize the stream be specified in the Testing and Monitoring Plan. An owner or operator who is also subject to requirements under Subpart RR of the Greenhouse Gas Mandatory Reporting Rule may note that the carbon dioxide composition samples must be collected from a point immediately upstream or downstream of the flow meter [40 CFR 98.440-98.449]. Additional information on Subpart RR may be found in the Subpart RR General Technical Support Document (TSD) (USEPA, 2010).

3.1.1 Flue Gas Analysis Methods

General Information

Owners or operators may consider the feasibility of adapting gas analysis methods from industrial applications to the monitoring needs of a GS project (in which analysis methods are used in post-capture analysis of the carbon dioxide stream). In industrial settings, flue gas analysis is conducted both for determining the optimal operating conditions for equipment and for compliance with federal and state emissions standards. Monitoring in such settings may be conducted with portable analytical units or with dedicated stationary gas monitoring systems called continuous emission monitoring (CEM) systems.

There are several types of CEMs. Extractive CEMs, which withdraw a sample from the stream and convey it to sensors, may be the most amenable to a GS setting because they allow for a wide range of detector types and target analytes. EPA notes that a process providing continuous monitoring of the injection stream is not necessarily appropriate for all GS projects but might be beneficial in certain settings where the injectate could be subject to variable composition. Because CEMs are installed permanently, they require regular maintenance and a housing unit for protection from environmental conditions. CEMs are not adapted specifically for GS applications at this time, but EPA recommends that interested owners or operators consider discussing their needs with manufacturers.

Portable flue gas analyzers may be a viable option for periodic ex situ chemical analysis of the carbon dioxide stream. These instruments use infrared (IR) and electrochemical sensors to detect a variety of gas constituents, such as carbon dioxide, sulfur dioxide, nitrogen oxides, methane, oxygen, and carbon monoxide. Current manufacturer information on product specifications suggests that some units have detection limits sufficient to detect the levels of impurities expected in captured carbon dioxide streams (e.g., Sass et al., 2005).

Application

Extractive CEMs generally employ a sampling probe, filter, sample line, gas conditioning unit, flow meter, calibration port, and a series of gas analyzers (Jahnke, 2000). The types of CEMs available and their associated analytical techniques are further described in EPA's CEMs information and guidance documents (USEPA, 2007) and by Jahnke (2000). Extractive CEMs are capable of analyzing for key constituents expected in GS project injectate, including carbon dioxide, oxygen, sulfur dioxide, nitrogen oxides, and carbon monoxide, hydrochloric acid, mercury, volatile organic compounds (VOCs), and moisture. Analysis of arsenic in gases appears to be less frequently performed than mercury analysis, but it is likely to be accomplished by similar methods as mercury. The sensors employed in CEMs can include, among others, IR methods, chemiluminescence, electroanalytical methods, absorption spectroscopy, mass spectrometry, and gas chromatography. The selection of specific detectors in a unit would depend upon anticipated constituents in the carbon dioxide stream.

Portable flue gas analyzers employ IR methods, in particular non-dispersive IR (NDIR), and electrochemical sensors; they measure a more limited range of constituents than CEMs (e.g., carbon dioxide, oxygen, sulfur dioxide, nitrogen dioxide, methane, carbon monoxide) and do not measure metals or hydrocarbons. A sample of gas can be tested in situ using a probe or collected and transported to the measurement device. Grab samples are often collected for analyses where it is not practical or safe to insert a probe (Fegen, 2005).

EPA recommends that the owner or operator evaluate the detection range of the analyzer for each constituent to ensure that any necessary dilution takes place. They may need to consult with manufacturers to ensure that potential analytical interferences among constituents are minimized. For example, several gases have NDIR absorption bands that are close together (Jahnke, 2000); alternative IR bands may need to be used for some gases, or alternate analyzers chosen. It is recommended that a discussion of selected methods and their detection sensitivities is included in the Testing and Monitoring Plan and discussed with the UIC Program Director.

Interpretation

The data from flue gas analyzers are reported either as parts per million by volume (ppmv) or milligrams per cubic meter (mg/m^3). The conversion of mg/m^3 to ppmv for each component requires converting milligrams to moles then to cubic meters with an equation of state. CEMs provide nearly continuous data that are usually sent to a remote computer.

3.1.2 Laboratory Chemical Analysis

General Information

Owners or operators may consider the feasibility of adapting laboratory analysis methods employed for non-GS carbon dioxide applications. Injectate samples may be collected at the wellhead or transmission line and transported to an in-house, temporary, or off-site laboratory that has expertise in the analysis of gas samples and that is deemed acceptable by the UIC Program Director. (The Testing and Monitoring Plan should identify any commercial laboratories the owner or operator plans to use for chemical analyses of the injectate.)

Carbon dioxide is used for laboratory applications in supercritical fluid extraction and supercritical fluid chromatography, which require the carbon dioxide to be high quality. Accordingly, ASTM International (ASTM) has developed a standard guide for the purity of carbon dioxide intended for such applications (ASTM, 2011). This standard includes descriptions of analytical methods such as gas chromatography and the use of a total hydrocarbon analyzer. These methods may be considered for adoption in analyzing the carbon dioxide stream for certain types of impurities. For example, an adsorbent concentration method followed by gas chromatography may be used for the analysis of hydrocarbons and halocarbons. A method published by the South Coast Air Quality Management District (2008; Method S.C. 10.1, alternative to EPA Method 10) analyzes carbon dioxide in a gas sample by gas chromatography with detection performed by a NDIR detector.

Some equipment manufacturers have developed similar methods suitable for the analysis of impurities in carbon dioxide. These methods use gas chromatography for separation of the various constituents in the sample, followed by detection with any of several available instruments. Gas chromatographic methods have much lower detection limits than the IR and electrochemical detectors used in portable flue gas analyzers or CEMs. The descriptions below are intended to provide examples of the analytical approaches available for various constituents that may be present in a carbon dioxide stream. Owners or operators are encouraged to contact commercial laboratories that handle gas samples to discuss their site-specific analytical needs.

Application

Gas chromatography with a pulsed flame photometric detector and flame ionization detector (FID) can be used for measuring trace sulfur and hydrocarbon constituents in carbon dioxide streams (e.g., Agilent, 2010). This method permits highly sensitive analyses of sulfur gases (hydrogen sulfide, sulfur dioxide, carbonyl sulfide) and some hydrocarbons (e.g., acetaldehyde, benzene and light hydrocarbons). In addition, gas chromatograph analyzers have been specifically designed for detection of impurities in food-grade carbon dioxide. These units use a sulfur chemiluminescence detector for sulfur compounds (e.g., hydrogen sulfide, carbonyl sulfide, sulfur dioxide, mercaptans, aromatic sulfur compounds). A photo ionization detector (PID) is used for aromatic hydrocarbons (benzene, toluene, xylenes, ethylbenzene), and an FID is used for certain other hydrocarbons (Arnel, 1999). A nitrogen chemiluminescence detector can be used for measurement of nitrogen oxides.

Mercury in flue gases is generally measured by one of several forms of spectroscopy. ASTM Method D5954 (ASTM, 2006a) describes a method for measurement of both inorganic and organic mercury in natural gas. The mercury is pre-concentrated by adsorption onto gold-coated beads and analyzed by atomic absorption spectrophotometry. Another method, cold vapor atomic fluorescence spectrometry, uses a sorbent trap that is inserted into a natural gas stream, with a metered amount of gas passed through it. The mercury is detected by fluorescence spectrometry (EPA Method 1631 Revision E; USEPA, 2002c). Arsenic may be similarly quantified by retention onto a solid sorbent followed by analysis by X-ray fluorescence or atomic spectroscopic techniques (e.g., Attari and Chao, 1993).

Interpretation

The detection methods that are coupled to gas chromatography generally produce outputs in the form of concentrations in micrograms per liter (µg/L) or, at the same analyte density, parts per billion by volume (ppbv). Common software packages used with gas chromatographic methods automatically calculate chemical concentrations from chromatogram curves, requiring calibration data to be provided. Formal analytical reports take the form of chromatograms with peak areas and resulting concentrations.

3.1.3 Reporting and Evaluation of Carbon Dioxide Stream Analysis

The Class VI Rule requires that the owner or operator submit any new data from analysis of the carbon dioxide stream in the semi-annual reports [40 CFR 146.91(a)(7)]. The data are required to be submitted to EPA in an electronic format [40 CFR 146.91(e)], and it is recommended that the submission include:

- A list of chemicals analyzed, including carbon dioxide and other constituents (e.g., sulfur dioxide, hydrogen sulfide, nitrogen oxides).

- A description of the sampling methodology, noting any differences from protocols listed in the Testing and Monitoring Plan and an explanation of why a different method was used.

- Any laboratory analytical methods used, the name of the laboratory performing the analysis, and official laboratory analytical reports including sample chain-of-custody forms.

- All sample dates and times.

- A tabulation of all available carbon dioxide stream analyses, including any quality assurance/quality control (QA/QC) samples.

- Interpretation of the results with respect to regulatory requirements and past results.

- Identification and explanation of data gaps, if any.

- Any identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs.

The UIC Program Director will evaluate the submittal to ensure that the composition of the injected stream is consistent with permit conditions and that it does not result in the injectate being classified as a hazardous waste.

3.2 Continuous Monitoring of Injection Rate and Volume

General Information

The Class VI Rule requires the use of continuous recording devices to monitor injection rate and volume and/or mass [40 CFR 146.88(e)]. The monthly average, maximum, and minimum values for injection pressure, flow rate, and volume must be reported to the UIC Program Director by the owner or operator in the semi-annual reports [40 CFR 146.91(a)(2)]. This information is used to verify compliance with the operational conditions of the permit and to inform AoR reevaluation.

Flow rate data are also used to determine the cumulative volume of carbon dioxide injected [40 CFR 146.91(a)(5)], which is not measured directly. If flow rate is measured on a mass basis (e.g., kg/sec), pressure and temperature measurements can be used to determine fluid density and convert mass values to volumetric measurements. Use of flow rate on a mass basis is particularly recommended because carbon dioxide is compressible; mass, in conjunction with downhole pressure and temperature data, can constrain the volume of the injectate at depth, helping to understand volume data as related to reservoir storage capacity. In performing this calculation, owners or operators should be aware of how the composition of the carbon dioxide stream may affect its density. Additional information may also be found in the Subpart RR General TSD (USEPA, 2010).

Injection rate can be continuously monitored using a flow metering device. Flow metering is a common practice in most industrial processes, and many types of flow meters have been developed for a variety of applications. The applications most similar to GS include metering of natural gas and carbon dioxide in the petroleum industry. The types of meters used in these practices include differential pressure meters (orifice plates, venturi meters); velocity meters (turbine meters, ultrasonic meters), which measure the velocity of the fluid; and mass meters (thermal meters, Coriolis meters), which measure the mass of fluid flow past the meter. These approaches are discussed in more detail in the following sections, and schematics of common flow meters are given in Figure 3-1. Because continuous measurement of injection rate and volume is important for verifying that the well is operating as stipulated by the UIC permit, the UIC Program Director may, in certain circumstances, require the owner or operator to have backup flow meters. This may be appropriate in projects where operating conditions are variable or if conditions are near the tolerance limits or measurement range for the flow meters.

Application

Differential pressure meters and velocity meters depend upon the properties of the fluid, especially temperature, pressure, and density. If the fluid properties are known and constant, they can be programmed into the meter, which can calculate flow rate. Density can either be measured directly or it can be calculated using equations of state and pressure and temperature readings. Otherwise, these values will need to be measured and input to a separate computational device. Measurements from mass flow meters do not depend on the pressure and temperature of the gas, and these meters do not require additional instrumentation. Thermal meters do require knowledge of the heat capacitance of the fluid. If the heat capacitance is expected to change because of variations in fluid composition, then fluid composition will need to be measured. In all cases, signals from the flow meter will be input into a device that will calculate the flow rate. The flow rate can then be recorded and stored electronically.

In selecting a meter type, owners or operators should weigh the advantages of the various meter types against their monitoring goals and needs. In preparing the Testing and Monitoring Plan, owners or operators should describe the expected accuracy and precision of their proposed meters and explain how they compare to their anticipated pressures and the sensitivity needed to detect deviations from permitted conditions. Owners or operators should also consider any potential shifts in accuracy or precision that may take place in their meters due to wear, exposure to carbon dioxide, and age. Proposed maintenance and calibration procedures should be included in the Testing and Monitoring Plan, along with procedures for determining when replacement is necessary. In addition, owners or operators should specify in the Testing and Monitoring Plan how average values will be calculated for injection pressure, flow rate, and volume pursuant to reporting requirements under the Class VI Rule, at 40 CFR 146.91(a).

Orifice plate differential meters are one of the most common meter types used to measure gas flow. They are considered standard in natural gas pipelines and carbon dioxide pipelines (McAllister, 2005). Orifice plates use Bernoulli's equation to determine flow by measuring the pressure drop across a plate with a hole (Maxiflo, 2009). Orifice meters are simple to use, have no moving parts, and are not as sensitive to density changes as some other meter types. Disadvantages include a limited range and lower accuracy than other meters.

Venturi differential meters use the same principle as orifice plates, but the pressure differential is measured across a constriction in a long tube. The constriction gradually widens out to the original pipe diameter, and this slow widening allows some recovery of pressure and results in a lower pressure drop than in an orifice plate. The advantages of a venturi meter are similar to those of an orifice plate; they are simple and have no moving parts. They tend to be more accurate than orifice plates but have a higher sensitivity to fluid properties.

Turbine velocity meters operate by placing a multiple-blade rotor in the flow path perpendicular to the flow direction. The flow moves the rotors and the flow rate is calculated by measuring the rotational speed of the blades. Turbine movement can be measured by magnetic pickup, photoelectric cells, gears, or tachometers. The advantages of turbine meters are high accuracy and applicable range of flow. Disadvantages include high pressure drop, dependence on fluid properties, and potential wear of moving parts.

Ultrasonic velocity meters operate by measuring ultrasonic waves as they travel through the fluid. There are two types of ultrasonic meters: Doppler meters and transit time meters. Doppler meters measure the change in frequency of ultrasonic waves reflected from entrained particles or bubbles and are not appropriate for measuring gases. Transit time instruments measure the time it takes for ultrasonic waves to travel between sensors both with and against the flow. The difference between the measurements is proportional to the flow. The advantages of ultrasonic meters are that they do not cause a pressure drop and are available in clamp-on varieties that can be retrofitted to pipes without cutting the pipe or stopping flow. Disadvantages include the fact that carbon dioxide strongly attenuates ultrasound waves, therefore requiring specially designed instruments to offset the attenuation caused by carbon dioxide (van Helden et al., 2009).

Thermal mass meters use a heating element that is isolated from the flow. The amount of heat conducted away from the element is proportional to the mass flow. Built-in calibrations allow the unit to convert the temperature change to a flow rate. An advantage of thermal mass meters is that they operate independently of pressure, density, and viscosity. They are intermediate in accuracy, and their operating range is less than those of turbine and ultrasonic meters but greater than those of orifice plates and venturi meters. They cause a lower pressure drop than most meters with the exception of ultrasonic meters. Disadvantages include a high dependence on accurate calibration.

Coriolis mass meters are based on the Coriolis force experienced by the fluid as it passes through a vibrating tube. The flow passes through a bent tube that is vibrated using a magnetic device. The flow in the tube resists the motion caused by the vibration and causes the tube to twist. The twist is proportional to the mass flow rate. Sensors measure the speed of the vibration and use it to calculate the mass flow rate. The advantage of Coriolis meters is that they are independent of fluid properties such as temperature, pressure, density and viscosity. They can measure an intermediate range of flow rates and produce an intermediate pressure drop.

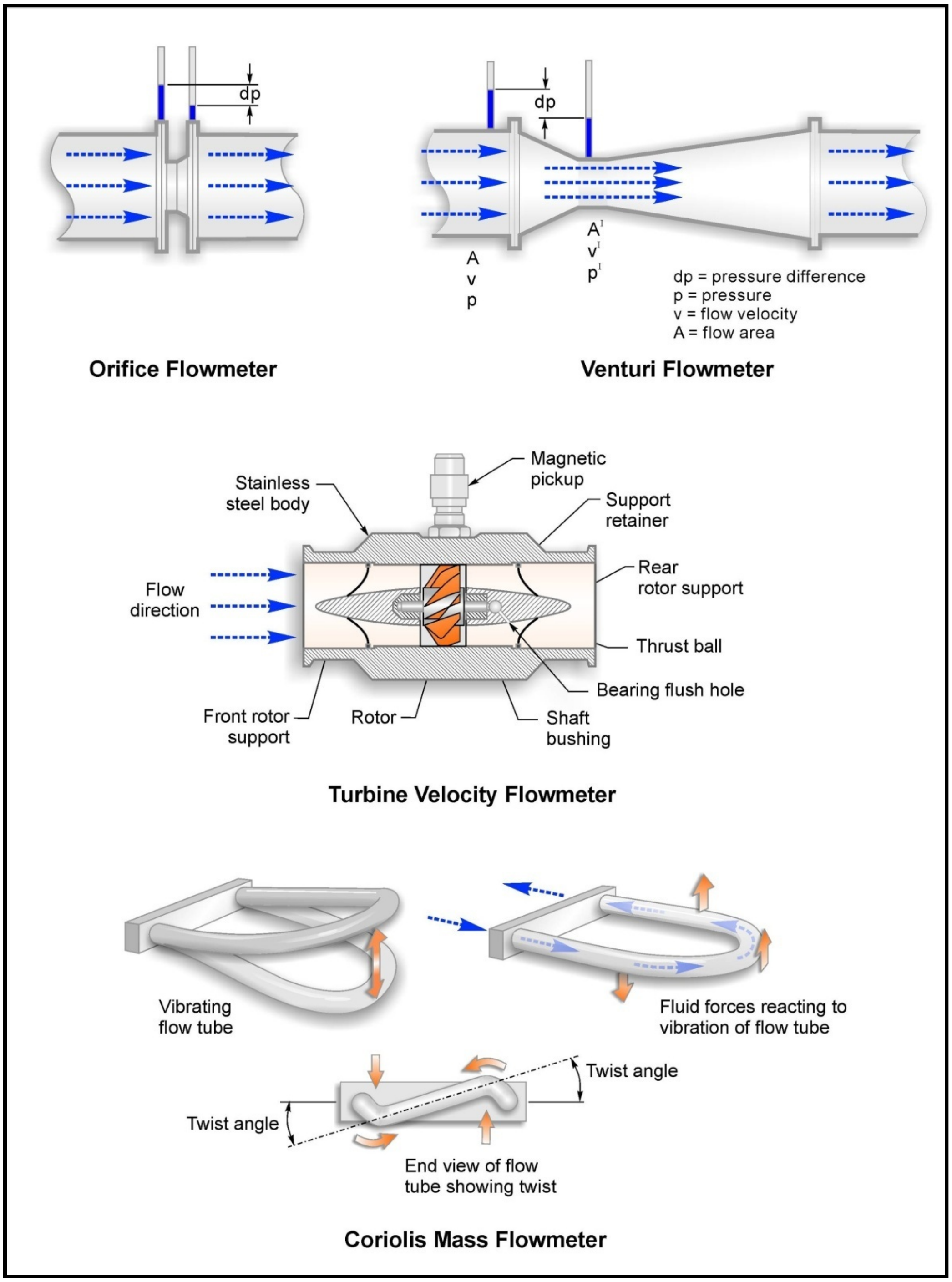

Figure 3-1. Schematic of common flow meters (not to scale).

Industry standards for flow meter applications should be consulted during selection, installation, and use. Relevant industrial standards include:

- American Gas Association (AGA) Report No. 11 – Measurement of Natural Gas by Coriolis Meters.
- AGA Report No. 9 – Measurement of Gas by Multipath Ultrasonic Meters.
- AGA Report No. 3 – Orifice Metering of Natural Gas.
- AGA Report No. 7 – Measurement of Natural Gas by Turbine Meter.
- ASME – MFC-3M-2004 – Measurement of Fluid Flow in Pipes Using Nozzle, Orifice, Venturi Meters.
- ASME – MFC-4M-1986 – Measurement of Gas Flow by Turbine Meter.
- ASME – MFC-11M-2006 – Measurement of Fluid Flow by Coriolis Mass Flow Meters.

Interpretation

The various meters discussed above will provide either flow rate data in units of volume or mass per time, or fluid velocity data in units of length per time. Injection flow rates may be calculated from velocity data by multiplying measured values by the cross-sectional area of the pipe or tubing at the measurement point. An example of a plot of measured injection rate over time is provided in Figure 3-2. Injection volumes are calculated by multiplying measured flow rates by the length of time for which the flow rate measurement is valid. Cumulative injection volume may be continuously calculated over the life of the project and the term of the reporting period. In addition, if volume (rather than mass) measurements are taken, it is recommended that the total mass of the injectate be calculated based on density as determined by pressure and temperature.

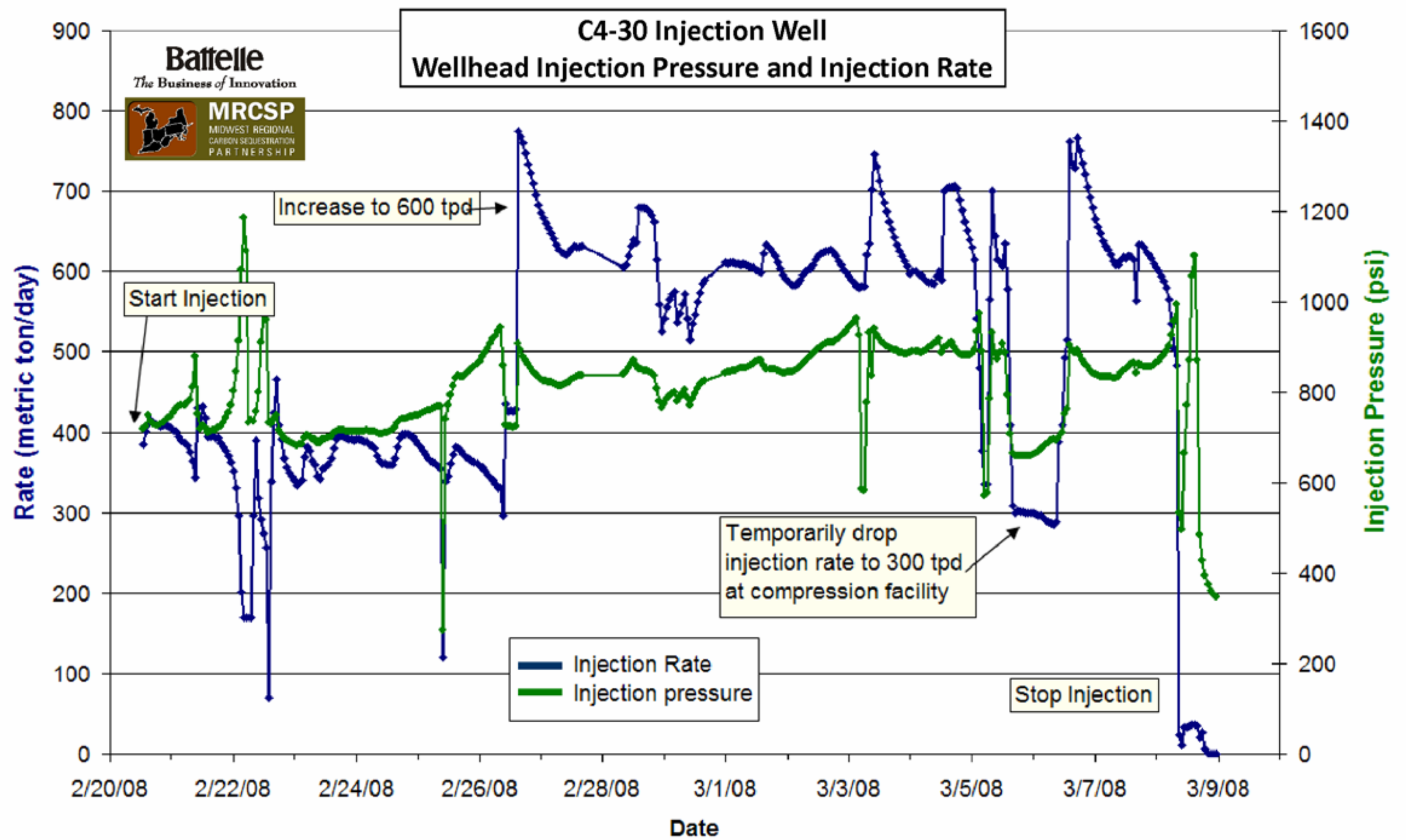

Figure 3-2. Example plot of measured injection rate and pressure measured at wellhead, Midwest Regional Carbon Sequestration Partnership (MRCSP) Michigan Basin Validation Test (image provided by Battelle Memorial Institute).

Reporting and Evaluation

Injection rate data must be submitted to EPA in the semi-annual reports [40 CFR 146.91(a)(2)]. Data will be submitted in electronic form directly to EPA, where they can then be accessed both by the UIC Program Director and other EPA offices. Monthly average data submissions are expected for each of the six months covered in the report. It is recommended that all of the information below be included in the report:

- Tabular data of all flow rate measurements and a description of interpretation of the data aided with charts or graphs.
- A description of the measuring methodology and technology, noting any differences from protocols given in the Testing and Monitoring Plan and an explanation of why a different methodology was used.
- Monthly average flow rate.
- Monthly maximum and minimum values.
- Total volume (mass) injected each month.
- Cumulative volume (mass) for the project.
- If flow rate exceeded permit limits during the reporting period, an explanation of the event(s), including the cause of the excursion, the length of the excursion, and response to the excursion.
- Identification and explanation of data gaps, if any.
- Any identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs.

The UIC Program Director will evaluate the data to determine compliance with permit conditions. The owner or operator is required to report, within 24 hours, any noncompliance with a permit condition that may cause fluid migration into or between USDWs [40 CFR 146.91(c)(2)].

3.3 Continuous Monitoring of Injection Pressure

General Information

The Class VI Rule requires the installation and use of continuous recording devices to monitor injection pressure [40 CFR 146.90(b)]. Injection pressure may be defined either at the wellhead (i.e., wellhead pressure) or downhole (i.e., bottomhole pressure). Bottomhole pressure is equal to wellhead pressure plus the hydrostatic pressure that exists due to the weight of the fluid column between the wellhead and bottomhole, minus frictional losses. Injection pressure is monitored to ensure that the fracture pressure of the formation and the burst pressure of the well tubing are not exceeded and that the owner or operator is in compliance with the permit. If these pressures are exceeded, the formation may fracture or the tubing may burst. An example of a plot of measured injection pressure over time is provided in Figure 3-2, on page 39.

Application

With an accurate knowledge of fluid density, bottomhole pressure can generally be estimated from wellhead pressure measurements. However, due to temperature effects, measuring bottomhole pressure with a dedicated downhole pressure gauge may be a more reliable approach than a device at the wellhead. EPA recommends that owners or operators consider placement of bottomhole pressure gauges in such a way that protects the perforations and the packer; choice of placement should be included in the Testing and Monitoring Plan, along with plans for calibration or other instrument checks.

Pressure gauges are commonly used instruments that have been developed for a wide range of applications. There are several types of pressure gauges (described below), which can be broadly classified as mechanical or electronic devices. Mechanical gauges are generally considered less accurate compared to electronic gauges, but can withstand more severe conditions. Electronic gauges also require a power source. For additional information regarding pressure monitoring, see Shepard and Thacker (1993), USEPA (1998), and ASTM (2009).

Amerada gauges are mechanical devices that consist of a helically wound Bourdon tube that bends in response to the pressure differential between the inner and outer surfaces. As the tube moves, it moves a stylus, which records the pressure on a chart. It is used mainly if the temperature is expected to be greater than 175˚ C.

Strain gauges are electronic devices bonded to a pressure transducer. The transducer can consist of wires wrapped around the inside of flexible tubing or a plate attached to a diaphragm. The resistance of the transducer changes as it is stretched by the pressure. The transducer is connected to a Wheatstone bridge, which can determine the resistance in the transducer. The resistance is related back to pressure by means of a calibrated curve showing pressure versus resistance. These gauges are rugged, have a long life span, and have a high pressure range. Disadvantages may include a larger drift than other gauges and a higher sensitivity to temperature changes.

Capacitance gauges are electronic gauges that consist of two plates set a very small distance apart (0.001 to 0.002 inches) that act as the capacitor in a circuit. Deflections in one plate caused by pressure change the capacitance of the circuit. A reference curve relates the changes in capacitance to pressure. These gauges are among the more common types. They can exhibit slower response times if the oil used to fill the device leaks. In addition, their use is limited to environments where the temperature is less than 220˚ C.

Vibrating crystal transducers are electronic gauges consisting of a quartz crystal wired to an electrical circuit. The crystal oscillates with a frequency that is pressure dependent. A second crystal that is not exposed to pressure is often used to correct for temperature. These gauges are highly accurate, but they are not as robust as other gauges and have a slow dynamic response. A variation on the vibrating crystal transducer uses a sapphire crystal (instead of a quartz crystal), which is not as accurate as the quartz version but works at higher pressures (20,000 psi) and temperatures (190˚ C).

Fiber optic transducers are a relatively new category of electronic gauges. They generally measure the changes in either phase modulation or polarization rotation of light in the fiber optic cable caused by pressure changes. Advantages include their immunity to electromagnetic interference, small size, and good dynamic response. However, they are not as robust as other types of gauges, are more sensitive to temperature changes, and perform poorly with static pressure measurements.

Reporting and Evaluation

Measured pressure data must be submitted to EPA in the semi-annual reports [40 CFR 146.91(a)(2)]. Data will be submitted in electronic form directly to EPA, where they can then be accessed both by the UIC Program Director and other EPA offices. The Class VI Rule requires that certain information be included in these reports [40 CFR 146.91(a)], and it is recommended that all of the information below be included:

- Tabular data of all pressure measurements, a description of interpretation of the data aided with charts or graphs, and gauge calibration records.
- A description of the measuring methodology, noting differences from what is established in the Testing and Monitoring Plan and an explanation of why a different methodology was used.
- Corrections made due to the impacts of fluctuating injectate temperature.
- Monthly average value for injection pressure.
- Monthly maximum and minimum values for injection pressure.
- If pressure exceeded permit limits during the reporting period, an explanation of the event(s), including the cause of the excursion, the length of the excursion, and response to the excursion.
- Identification and explanation of data gaps, if any.
- Any identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs, including any changes in the data measurement or averaging methods.

The UIC Program Director will evaluate the data to determine compliance with permit conditions. If the pressure exceeded the permit conditions, this is considered a permit violation, and the UIC Program Director will take any necessary enforcement actions, evaluate the causes, and determine if there is any endangerment to the well and/or any USDWs. He or she will also determine if the permit needs to be modified or if changes are needed in any of the project plans (e.g., the Emergency and Remedial Response Plan). The owner or operator is required to report any noncompliance with a permit condition that may cause fluid migration into or between USDWs within 24 hours [40 CFR 146.91(c)(2)].

3.4 Corrosion Monitoring

Corrosion, which is the loss of metal due to chemical or electrochemical reactions, may result in loss of mass or thickness, cracking, or pitting of injection well components. General corrosion refers to the uniform, or near uniform, thinning of metal. In some cases, a certain rate of general corrosion may be acceptable, if a corrosion allowance has been included in the well materials' design thickness. Localized corrosion consists of several forms of attack that lead to failure of the equipment before the corrosion allowance is spent. Mechanical integrity loss may result from the development of a leak, from mechanical failure caused by localized thinning, or from crack propagation in the well components. Corrosion inhibitors or corrosion-resistant alloys are additional options to provide protection from corrosion and are discussed in the *UIC Program Class VI Well Construction Guidance*.

The Class VI Rule requires quarterly monitoring of well materials for corrosion [40 CFR 146.90(c)]. The objective of corrosion monitoring is early detection of deterioration of well components (casing, tubing, or packer) that may cause loss of mechanical integrity. It is recognized that carbonic acid corrosion of steel tubing and pipes is a concern in the oil industry (e.g., Palacios and Shadley, 1991; Lopez et al., 2003). Carbon dioxide in the presence of water will lead to the formation of carbonic acid; therefore, Class VI injection wells may be exposed to a more corrosive bottomhole environment than wells that do not inject carbon dioxide.

The Class VI Rule requires that well components be monitored for corrosion using at least one of the following methods: coupons, a flow loop, or an alternative method approved by the UIC Program Director [40 CFR 146.90(c)]. These methods are described in the subsections below. Additionally, the UIC Program Director may require the use of CILs on a periodic basis [40 CFR 146.89(d)] to monitor for corrosion. In addition to monitoring the injection well, EPA recommends that owners or operators consider corrosion monitoring for any monitoring wells. Monitoring wells remain idle, and their downhole environment may be prone to corrosion. In particular, any monitoring wells perforated in the injection zone may be exposed to carbon dioxide-bearing fluids, and are therefore particularly subject to potential corrosion.

3.4.1 Use of Corrosion Coupons

General Information

The most common of all corrosion rate measurement tests involves exposing pieces of metal, similar to those in the injection system, to the conditions to which the well materials will be exposed. Small, pre-weighed and measured coupons made of the construction materials are exposed to well fluids for a defined period of time, then removed, cleaned, and weighed to determine the corrosion rate (Allen and Roberts, 1978). Coupons are very simple to use and analyze, and they give a direct measurement of material lost to corrosion. Coupons can predict the following types of corrosion when correctly emplaced to ensure appropriate exposure: general corrosion, crevice corrosion, pitting, stress corrosion cracking, embrittlement, galvanic corrosion, and metallurgical structure-related corrosion (USEPA, 1987a). However, coupons have several limitations. An extended period of time is required to produce useful data, and coupons can only be used to determine average corrosion rates. The inevitable differences in the size and thermomechanical history of coupons compared with the actual well materials mean that the corrosion rate measured on a coupon cannot exactly match the corrosion rate experienced by the well (USEPA, 1987a); therefore, lack of serious corrosion in coupons does not conclusively rule out corrosion of well materials.

Application

A coupon is a small, carefully manufactured piece of metal (such as a strip or ring) placed in an appropriate location in the injection well to measure corrosion (Figure 3-3). The coupon is made from the same material as the well's casing or tubing. It is weighed, subjected to the well environment for a period of time, and then removed and weighed again. The average corrosion rate in the well can be calculated from the weight loss of the coupon (Jaske et al., 1995).

Coupons are typically placed in the well using wireline equipment (USEPA, 1987a). Carriers that hold one or more coupons have been developed in the oil and gas industry to monitor corrosion in production wells (NACE, 2005). Coupons might also be deployed at the surface in a valved loop through which the injection stream passes. In a Class VI well, coupons deployed either downhole or in a loop near the wellhead will register the effects of the carbon dioxide on the material on the inside of the tubing. Importantly, corrosion coupons can only measure corrosion in the part of the well in which they are placed. For example, Smith and Pakalapati (2004) described a production scenario where extensive corrosion caused joints to collapse although coupons at the wellhead of the same well indicated minimal corrosion rates. In addition, the coupon material needs to match the material of concern as closely as possible. When not in use, coupons need to be stored in a non-corrosive environment. Specialized envelopes and other containers are available for coupon storage.

NACE International (NACE) Recommended Practice RP-0775 (NACE, 2005) provides technical information and best practices for coupon use in oil and gas applications, including more detailed technical information on preparing, analyzing and installing corrosion coupons. ASTM Standards G1 (ASTM, 2003) and G4 (ASTM, 2008) provide additional technical information on preparing and evaluating corrosion coupons.

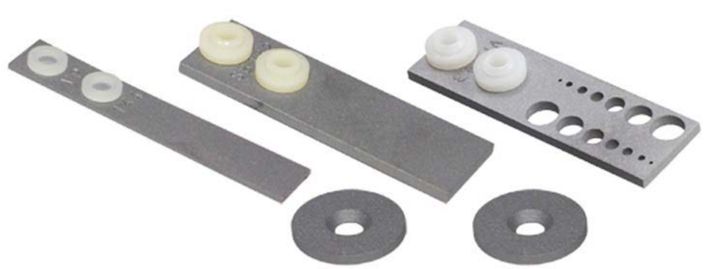

Figure 3-3. Example of corrosion coupons (image from Rohrback Cosasco Systems, reprinted with permission).

Interpretation

Corrosion rates are commonly reported in mils per year (mpy) of penetration or metal loss, where a mil is equal to a thousandth of an inch. Target corrosion rates of one mpy (approximately 25 µm/year) or less are common in wells used in the oil industry. A low corrosion rate may not be acceptable if localized corrosion (such as pitting) is occurring, whereas a higher rate with a general area type of metal loss may be, in certain cases, a relatively insignificant problem (USEPA, 1987a). Inspection of the coupon's surface can yield information about the nature of the corrosion that is taking place (e.g., localized or general attack, presence of pitting or cracking).

The difference in the size and thermomechanical history of a coupon compared with actual items of equipment may result in differences in the measured corrosion rates. Nevertheless, coupons provide the simplest and most useful guide to corrosion monitoring, particularly localized corrosion effects. When suitably fabricated and exposed, coupons predict general corrosion, crevice corrosion, pitting, stress corrosion cracking, embrittlement, galvanic corrosion, and metallurgical structure-related corrosion.

3.4.2 Use of Corrosion Loops

General Information

Another method of assessing corrosion is the use of a corrosion loop. A corrosion loop is a section of tubing that is valved so that some of the injection stream is passed through a small pipe running parallel to the injection pipe at the surface of the well. Because the composition of this pipe is the same as the well tubing, it acts as a small-scale version of the well; the only differences are that the loop pipe has a smaller diameter and its temperature (due to its shallower depth) is generally lower (USEPA, 1987a). Pressure differences between the injection point and the wellhead are also important to note. Although not as commonly used in the field as coupons, use of flow loops is a viable corrosion monitoring option.

Application

In a field setting, the loop would consist of a section of tubing that is valved so that some of the injection stream is passed through a small pipe running parallel to the injection pipe at the surface of the well. The pipe can then be analyzed for corrosion. When the valves are open, some of the injection stream passes through the loop. When the valves are closed, the corrosion loop can be removed from the system and analyzed for corrosion. Corrosion rates can be calculated in a similar fashion to the corrosion coupon method.

Interpretation

If corrosion is observed in the loop, corrosion is likely occurring in the well tubing. Because the dimensions and temperature of the loop are different than that of the well, conditions in the loop do not exactly match the conditions in the well, and the loop may be subject to more or less corrosion than the well itself. For example, temperature usually increases with depth, and therefore the temperature in the loop is generally less than the temperature of the well. Because corrosion rates increase with temperature, this may lead to an artificially low estimate of corrosion. EPA recommends that, where practical, consideration be given to controlling the temperature of the corrosion loops to simulate well conditions, thereby allowing for the collection of more representative corrosion rate information. In addition, loops cannot measure the corrosion experienced by specific features of the well (such as joints) that may have corrosion-enhancing properties (USEPA, 1987a).

3.4.3 Casing Inspection Logs

General Information

If required by the UIC Program Director, the owner or operator of a Class VI well must run a CIL at a frequency specified in the Testing and Monitoring Plan [40 CFR 146.89(d)]. The purpose of the CIL is to determine the presence or absence of corrosion in the long-string casing. CILs measure casing thickness or borehole radius. One of several available logs may be used for a CIL, including physical measurement with a caliper, electromagnetic phase shift in the magnetic field passing through the tubing or casing, electromagnetic flux leakage due to variations in the tubing or casing, and ultrasonic images of reflected sound waves. Each of the methods provides data that, along with the physical characteristics of the well, will yield the thickness of the casing and the locations of anomalies, such as corrosion pits, scratches, and splits. The choice of appropriate test is based on operator preferences and subject to approval by the UIC Program Director.

Application

All CIL tools are wireline based and identify and measure variances, referred to as defects, in the thickness of the casing wall. Examples of defects are pits or ruts (formed by corrosion, substandard welds at casing couplings, wear from centralizers or collar locators, etc.) and splits that open gaps in the casing.

Caliper logs measure the internal radius of the casing in several directions (see the *UIC Program Class VI Well Construction Guidance*). A loss of thickness of the casing is evident from a caliper log because the internal radius increases in the area of corrosion. Baseline caliper surveys may be used for comparison. An example of a caliper log showing significant casing corrosion is provided in Figure 3-4.

An **electromagnetic thickness survey** measures large defects on the order of one inch (USEPA, 1982; Nielsen and Aller, 1984). The tool has an emitter coil (low frequency) used to create a magnetic field that passes through the tubing or casing and a receiver coil that measures the shift in the returning magnetic field. The receiver coil is set at a distance where it intercepts magnetic field lines that pass outside the coil. The phase shift is proportional to the thickness of the metal and the casing's magnetic permeability. Properties of the casing affect the log, so properties such as the material and density of the casing need to be known before the baseline log is run. The results are relative and need to be compared to a baseline log. If a CIL is run when the well is first installed to satisfy the requirements at 40 CFR 146.87(a)(4), it can serve as a baseline to which measured casing thickness can be compared..

One commercially available electromagnetic scanner offers the advantage of not requiring the tubing to be pulled if the inner diameter is sufficiently large to accommodate the instrument.

Qualitative results can be obtained for tubing and casing together. If metal loss is indicated, the tubing would then be removed to determine if the loss is in the casing or tubing.

The **pipe analysis survey** is a form of magnetic flux-leakage test that measures disturbances in an artificially created magnetic field (USEPA, 1982). The logging tool consists of an electromagnet, two arrays of pads, two cartridges of electronics, and centralizers (Nielsen and Aller, 1984). Each pad contains upper and lower electric coils used to measure flux leakage and eddy currents, and an eddy coil to produce eddy currents along the inner wall. The coils collect data in the form of induced currents that are converted to casing variations on the log. The pads are set around the tool to give circumferential coverage for the survey.

The **ultrasonic imaging survey** uses a very high transducer frequency to measure anomalies in the tubing or casing (Schlumberger, 2009). The emitter/detector is on the end of the wireline tool, with centralizers located above. The emitter sends out sound waves and the detector measures the reflected response. The survey can measure anomalies as small as 0.3 inches and measures anomalies both on the inner and outer surfaces of the tubing or casing. The tool rotates, but the electronics keep track of a reference point, and it can therefore produce an accurate circumferential image of the tubing or casing. The data are analyzed and yield the thickness and inner and outer surface conditions. The survey response is attenuated by the fluid in the well bore and the best results are produced with oils, brines, and light muds.

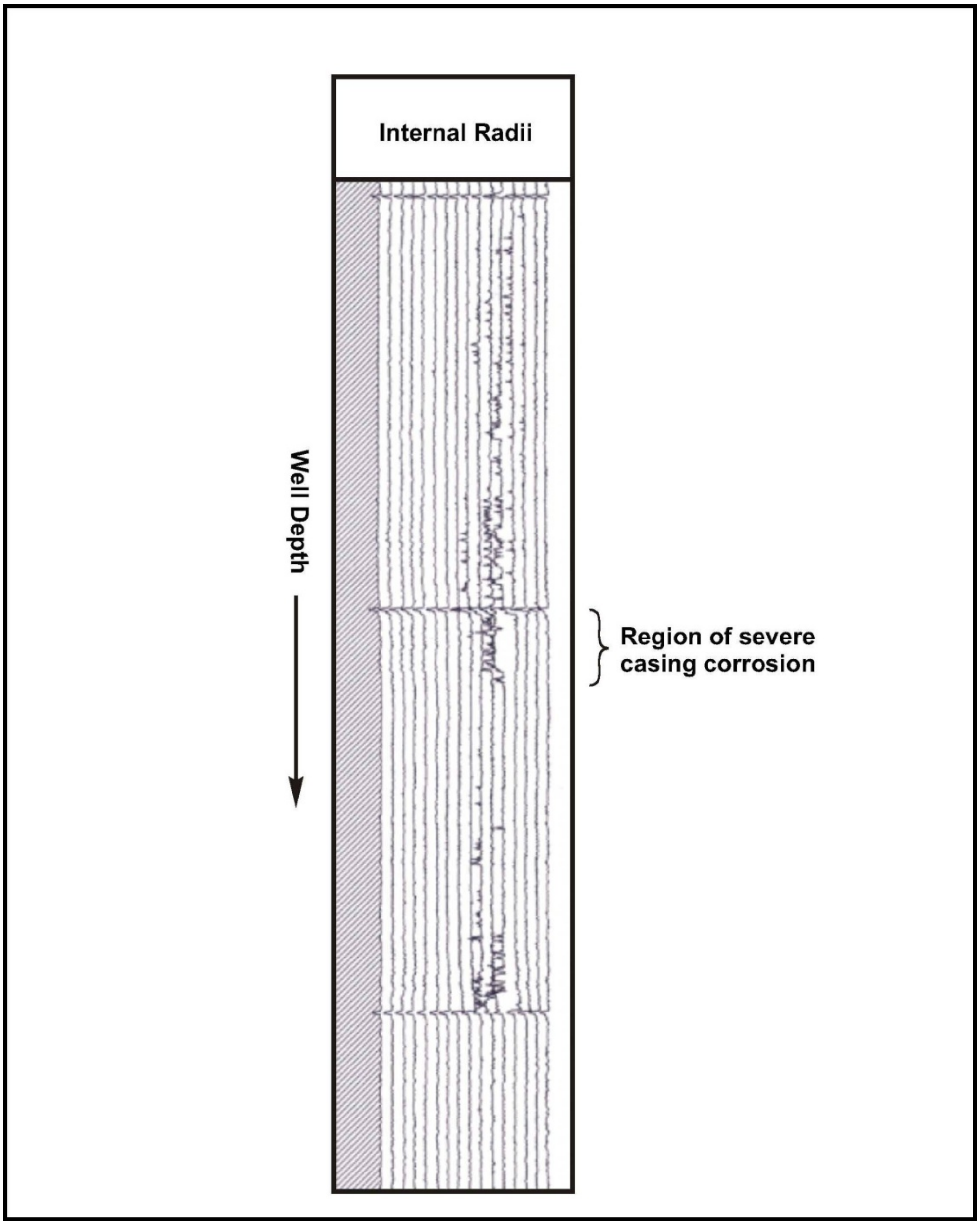

Figure 3-4. Example CIL (caliper log) showing significant corrosion (Brondel et al., 1994). Graphic copyright Schlumberger. Used with permission.

Interpretation

The data from each of the CILs are displayed as vertical logs (e.g., Figure 3-4). Defects in the long-string casing will be displayed as anomalies on the log that cannot be attributed to casing joints or other construction features. Loss of thickness may be determined from comparison to baseline logs. For any of these tests, time series logs can be used to gauge the growth of defects and predict eventual loss of mechanical integrity.

The caliper log is generally reported as internal radius, nominal wall penetration, or average remaining thickness, depending on the logging company. Some logs can even show the variation detected by each arm as side by side traces similar to a seismograph (see Figure 3-4). The ultrasonic imaging survey produces images of the surfaces and a log of the thickness.

Knowledge of the casing properties is needed to properly interpret CILs. The information used in interpreting the log consist of dimensions, weights and alloys, locations of couplings, locations of wall scratches or other abrasions, locations of perforations, and locations of centralizers. Couplings will show an increase in thickness and are usually spaced at regular, but always known, intervals (e.g., Figure 3-4). Perforations will show as defects but typically yield a regular output. Variation within the perforated sections can show corrosion in the perforations.

3.4.4 Reporting and Evaluation of Corrosion Monitoring Data

Owners or operators are required to submit the results of corrosion monitoring in the semi-annual reports [40 CFR 146.91(a)(7)]. Data will be submitted in electronic form directly to EPA, where they can then be accessed both by the UIC Program Director and other EPA offices. Certain information must be included in these reports [40 CFR 146.91(a)], and EPA recommends that all of the following information be included:

- A description of the techniques used for corrosion monitoring.
- Measurement of mass and thickness loss from any corrosion coupons or loops used.
- Assessment of additional corrosion, including pitting, in any corrosion coupons or loops.
- Measurement of thickness loss or corrosion detected in any CILs.
- All measured CILs and comparison to previous logs.
- Identification and explanation of data gaps, if any.
- Any identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs.

The UIC Program Director will independently assess the results of corrosion monitoring to assess the integrity of the injection well.

3.5 Pressure Fall-Off Testing

General Information

The Class VI Rule requires pressure fall-off testing of the injection well at least once every five years, or more frequently if required by the UIC Program Director [40 CFR 146.90(f)]. Pressure fall-off tests are used to measure formation properties in the vicinity of the injection well (e.g., transmissivity). The objective of periodic testing is to monitor for any changes in the near-well bore environment that may impact injectivity and pressure increase. Anomalous pressure drops during the test may be indicative of fluid leakage through the well bore. However, during a transient pressure test for a GS project, the presence of multiple fluid phases, gravity driven flow, and dissolution of carbon dioxide in brine are likely to be important factors and should be considered (Benson and Doughty, 2006). For instance, phase changes and multiphase flow effects in a region near the front can cause a sharp pressure drop in that location. For additional information regarding pressure fall-off tests, see the USEPA Region 6 UIC Pressure Falloff Testing Guideline (USEPA, 2002a) or the course outline and notes from EPA's Nuts and Bolts of Falloff Testing seminar (USEPA, 2003). Information is also available in publications such as Schlumberger (2006), Kamal (2009), or Lee et al. (2003). Some portions of this section have been adopted from USEPA (2002a).

Application

Pressure fall-off tests are conducted by ceasing injection for a period of time (i.e., shutting-in the well) and monitoring pressure decay at the well. The results of the pressure fall-off test depend in part on the injection conditions prior to shutting-in the well. Therefore, prior to the test, it is recommended that injection rate and pressure be kept as constant as practicable and continuously recorded (Sections 3.2 and 3.3).

Upon shutting-in the well, pressure measurements are taken continuously. Temperature measurements taken during the test may assist in data interpretation. Bottomhole reservoir pressure measurements may be less subject to data scatter, and, because of the compressible nature of supercritical and liquid carbon dioxide, bottomhole gauges should be the least affected by well bore effects. Wellhead (surface) pressure measurements may be sufficient if a positive pressure is maintained at the surface throughout the test. The use of two pressure gauges is recommended, with one serving as a backup or for verification in cases of questionable data quality. It is recommended that the duration of the shut-in period be long enough to observe a straight line of pressure decay on a semi-log plot (i.e., radial flow is achieved). A general rule of thumb is to run the test for three to five times the time required to reach radial flow conditions.

For projects with multiple injection wells within the same zone, special considerations may be made for pressure fall-off testing, as injection at one well will influence the pressure fall-off curve at other wells. For the offset wells (i.e., those not being tested), injection should cease prior to the test for a period of time exceeding the planned shut-in period, or injection rates may be held constant and continuously recorded during the test. Following the fall-off test, owners or operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain inter-well reservoir parameters. For basic information on pulse tests, see Johnson et al. (1966) or Kamal (1983).

Interpretation

Pressure fall-off tests measure the change in pressure over time at the test well, and results are plotted as a function of time. Interpretation of pressure data for a GS project may be complex due to the presence of multiphase fluid flow. Benson and Doughty (2006) indicated that the effects of heterogeneity and gravity may cause high residual liquid saturation estimations in evaluating pressure transient test results in a carbon dioxide-brine system.

Typically, several graphs are used in interpretation of test results. Observed bottomhole pressure and recorded temperature may be plotted as a function of time for the time period prior to the shut-in and the duration of the test. This plot is used to confirm pressure stabilization prior to the test. Any pressure changes may be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution. Any data collected after reaching resolution of the gauge are suspect. Pressure gauges typically auto-correct for temperature fluctuations. However, if temperature anomalies are not accounted for correctly, this may lead to erroneous results. Any temperature anomalies observed during the test may be noted to determine if they correspond to pressure anomalies. Computational models that account for the presence of multi-phase fluids may be used to aid in interpretation of pressure fall-off tests if there are large temperature fluctuations.

Log-log and semi-log diagnostic plots of observed pressure and time are used for further data interpretation. Unique flow regimes can be identified on these plots, corresponding to the region(s) governing pressure fall off during a certain phase of the test. Early data correspond to flow within the well bore and the immediate surrounding area, and later data correlate to distances further from the well. Later-time data, representative of reservoir conditions, are used for quantitative data analysis. Observations of anomalous pressure decay at greater rates than previous tests may indicate a number of scenarios such as changes in relative permeability, the effects of well stimulation procedures, or leakage of fluid. See USEPA (2002a) for further information on interpretation of the diagnostic plots as they relate to detection of reservoir geologic features and leakage pathways.

Quantitative analysis of the measured data is used to estimate formation characteristics, including transmissivity, and the well skin factor. Analytical or numerical fluid flow models are fit to the measured data to estimate these parameters; commercial software programs are often used. The well skin factor accounts for changes in the permeability of the formation at or near the well bore as a result of drilling, completion, and injection practices (e.g., van Everdingen, 1953). Changes in permeability are also expected due to the presence of a multi-phase system and possibly due to mineral precipitation near the well bore. Owners or operators should be aware that interpretation of fall-off tests in carbon dioxide injection projects will be complicated by two-phase flow effects and should consider this when analyzing and reporting the data. EPA encourages the owner or operator to provide a description of any methods that may be used to account for multi-phase effects. Parameters determined in pressure fall-off tests may be compared to those used in site computational modeling and AoR delineation. Changes in formation permeability values as measured during pressure fall-off tests may also be required by the UIC Program Director to be reflected in AoR reevaluation.

Reporting and Evaluation

The Class VI Rule requires that the results of pressure fall-off tests be submitted to EPA electronically within 30 days of the test [40 CFR 146.91(e) and 146.91(b)(3)]. EPA recommends that submittals include:

- The location and name of the test well and the date/time of the shut-in period.
- Depths of bottomhole pressure and temperature.
- Records of gauges (if they are lowered and raised).
- Raw data collected during the fall-off test in a tabular format, if required by the UIC Program Director.
- Measured injection rates and pressure from the test well and any off-set wells in the same zone, including data from before shut-in.
- Information on pressure gauges used (e.g., manufacturer, accuracy, depth deployed) and demonstration of gauge calibration according to manufacturer specifications.
- Diagnostic curves of test results, noting any flow regimes.
- Description of quantitative analysis of pressure-test results, including use of any commercial software, and any considerations of multi-phase effects.
- Calculated parameter values from analysis, including transmissivity, permeability, and skin factor.
- Analysis and comparison of calculated parameter values to previously measured values (using any previous methods) and to values used in computational modeling and AoR delineation.
- Identification of data gaps, if any.
- Any identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs.

The UIC Program Director will evaluate the pressure fall-off test results to assess any changes in characteristics of the near-well bore environment and any indication of fluid leakage during the test.

4 Ground Water Quality and Geochemical Monitoring

The Class VI Rule requires periodic monitoring of ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide or injection formation fluid movement through the confining zone(s) or additional identified zones [40 CFR 146.90(d)]. The primary purpose of this monitoring is to identify potential injectate migration and/or native fluid displacement from the injection zone by detecting potential geochemical changes due to the introduction of the injectate or displaced formation fluids above the primary confining zone(s). EPA recommends that the geochemical monitoring be conducted in the first formation overlying the confining zone that has a sufficient permeability to support collection and analysis of ground water samples. However, the decision regarding which formation(s) to monitor will be based on site-specific conditions and will be determined in consultation with the UIC Program Director. The UIC Program Director may determine that monitoring ground water quality (or pressure) within additional zones, including USDWs, may be critical for a specific GS project. For GS projects operating under an injection depth waiver, the requirements for ground water quality and geochemical monitoring will necessitate measuring pressure and sampling fluids in at least one additional formation (the first USDW below the injection zone) and possibly other formations if specified by the UIC Program Director [40 CFR 146.95]. More detailed information is available for such projects in the *UIC Program Class VI Well Injection Depth Waivers Guidance*.

The spatial locations, depth, and number of monitoring wells required for the direct monitoring of ground water quality and geochemical changes in the identified zone(s) will also be site-specific and based on site characterization and operational information, including factors such as proposed injection rate and volume, geology, and the presence of artificial penetrations [40 CFR 146.90(d)(1)]. While determining the spatial distribution and depth of monitoring wells and the frequency of sampling, the owner or operator should also consider baseline geochemical data collected during site characterization under 40 CFR 146.82(a)(6), as described in the *UIC Program Class VI Well Site Characterization Guidance* [40 CFR 146.90(d)(2)]; the quality and time frame of these baseline data will be important when interpreting the geochemical monitoring results. Additionally, monitoring decisions will be based on AoR modeling results required under 40 CFR 146.84(c). If reactive transport modeling has been conducted, modeling results may also support the selection of parameters to be monitored.

EPA recommends that the Testing and Monitoring Plan include a detailed description of the number and placement of monitoring wells and the site-specific factors that have been considered, as well as a technical justification of the decision of which formations to monitor. Similarly, a discussion of the parameters to be monitored and the frequency at which sampling and analysis will be performed should be included in the plan. It is also important that the owner or operator describe method sensitivities and how the monitoring strategy will detect deviations in project performance and/or any endangerment to a USDW. If phased or triggered monitoring is proposed, all factors considered for the development of the strategy should be included in the plan (see Section 1.2.1).

This section discusses how owners or operators may design and construct a monitoring well network, collect and analyze ground water samples from above the primary confining zone, and interpret and submit the results of ground water analyses.

In addition to the above-confining zone water quality monitoring requirements [40 CFR 146.90(d)], the Class VI Rule also requires direct monitoring of the pressure front in the injection zone [40 CFR 146.90(g)]. Additionally, there may, in limited circumstances, be a need to monitor the separate-phase plume geochemically via direct sampling in the injection zone. This would occur if the UIC Program Director determines that indirect methods for tracking the plume (e.g., geophysical methods; see Section 5) required at 40 CFR 146.90(g) are not feasible at a particular project site and requires the use of direct monitoring for plume tracking. Because of this, some of the recommendations described in this section relate to developing an overall strategy for geochemical monitoring and a network of monitoring wells, both above the confining zone(s) and within the injection zone.

4.1 Design of the Monitoring Well Network

The monitoring well network refers to wells that are used to support compliance with the testing and monitoring requirements under the Class VI Rule. The design of the monitoring well network is a key component of a monitoring system that serves to detect any leakage through the confining zone that may endanger USDWs and support any direct monitoring required in the injection zone. Therefore, the owner or operator must consider all relevant site data, including injection rate and volume, geology, the presence of artificial penetrations, and other factors, as required at 40 CFR 146.90(d)(1) and (2), in planning monitoring well placement (i.e., both the depth of the wells and their geographic location with respect to the injection well(s) and anticipated injectate plume and pressure front movement). The proposed monitoring well placement and perforation strategies, along with a description of a monitoring well maintenance program, are to be described and technically justified in detail in the Testing and Monitoring Plan, based on site characteristics and computational modeling performed for AoR delineation, subject to UIC Program Director approval. This information should demonstrate that the proposed system can help verify that the injectate is safely confined in the target formation and be used to detect deviations from the predicted project performance.

The general sequence of site characterization, modeling, and monitoring at a GS project is shown in Figure 4-1. The model, based on site characterization and proposed operating data, is used to delineate the AoR. The reader is referred to the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for discussion of generating model results and delineation of the AoR. The AoR is then used in order to design the monitoring system. As more data are obtained from the site, the model is revised to reflect the additional data. If revision of the model results in a substantially different AoR, then the monitoring system may need to be redesigned and the Testing and Monitoring Plan updated.

This section provides guidelines for the design of the monitoring well network for ground water monitoring above the confining zone(s) and any other direct monitoring in the injection zone required under the Class VI Rule.

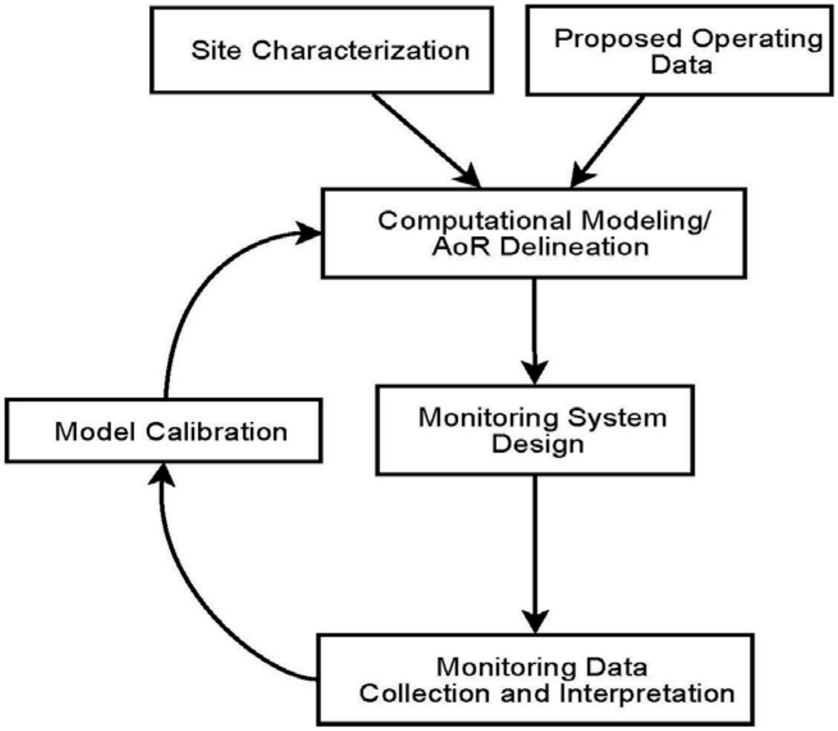

Figure 4-1. Flow chart of modeling and monitoring at a Class VI project.

4.1.1 Perforated Interval of Monitoring Wells

The perforated interval of a monitoring well refers to the depth at which openings or slots are present in the casing, allowing for native ground water at that interval to flow into the casing for sample collection. The monitoring well is designed to sample ground water only in the perforated interval (the hydrostratigraphic section of interest).

As discussed above, the Class VI Rule requires geochemical monitoring above the primary confining zone [40 CFR 146.90(d)]. However, the owner or operator, or the UIC Program Director, may determine that monitoring ground water quality (or pressure) within additional zones, including USDWs, is necessary to protect USDWs. For example, monitoring the ground water geochemistry of the lowermost USDW may be required by the UIC Program Director to detect potential fluid leakage into the USDW. Based on site-specific criteria, the UIC Program Director may also determine that geochemical monitoring within the injection zone is necessary for tracking of the carbon dioxide plume (see Section 5) if indirect methods are not appropriate for the given site. Therefore, at a minimum, the owner or operator is required to construct monitoring wells perforated above the confining zone in a suitable formation for collection of ground water samples [40 CFR 146.90(d)].

EPA recommends that monitoring wells above the confining zone be perforated in the first reasonably permeable formation above the confining zone (i.e., the first formation from which fluids can be extracted at appreciable volumes for sampling and analysis) unless the UIC

Program Director approves perforation in a shallower zone. Placing wells as close to the confining zone as possible will allow for earlier detection of leakage through the confining zone.

For GS projects operating under an injection depth waiver, monitoring will be needed both above and below the injection formation [40 CFR 146.95(f)(3)(i)]. Therefore, owners or operators may wish to install monitoring wells with multi-level samplers. See the *UIC Program Class VI Well Injection Depth Waivers Guidance* for more information.

4.1.2 Monitoring Well Placement

EPA recommends that monitoring wells be placed strategically to maximize the ability of the monitoring well network to detect potential leakage and track the migration of the plume (if required) and pressure front while minimizing the number of wells, which can serve as conduits for fluid movement. The Class VI Rule requires that the placement of monitoring wells used for geochemical monitoring above the confining zone be based on available site characterization data and AoR delineation modeling [40 CFR 146.90(d)(2)].EPA is providing the following recommended guidelines for determining the number and placement of monitoring wells above the confining zone(s) at a Class VI project based on available site characterization data and the results of computational modeling. The objective of these recommended guidelines is to inform the development of a monitoring network with a sufficient yet minimal number of monitoring wells that are strategically located to provide site monitoring that meets the requirements at 40 CFR 146.90(d)(1) and (2). These recommended guidelines are intended to provide a reference for owners or operators during the design of the monitoring well network, and for UIC Program Directors in evaluating the proposed Testing and Monitoring Plan. The guidelines are as follows:

- As depicted in Figure 4-1, the monitoring well network design will ideally build upon site characterization and computational modeling information, which will then be used to instruct placement of monitoring wells that will enable collection of baseline site data.

- The number of required monitoring wells may be greater for projects with larger predicted areas of elevated pressure and/or plume movement, or in cases of more complex or heterogeneous injection/confining zone hydrogeology. If the predicted area of impact of a given project increases in size as indicated during an AoR reevaluation, additional monitoring wells may be necessary.

- For projects with a separate-phase plume and/or pressure front predicted to move in a specific direction (e.g., due to formation dip), wells should be primarily placed in the predicted down-gradient direction. However, at least one up-gradient well is recommended.

- Well placement should be based on the predicted rate of migration of the separate-phase plume and/or pressure front.

- Wells sited above the confining zone(s) should be preferentially placed in regions of concern for potential risk of fluid leakage and USDW endangerment. These regions may include identified faults, fractures, or abandoned well bores (see the Cranfield and In Salah case studies in the Appendix) that may represent a potential pathway for fluid leakage into a USDW and are predicted to overlie the maximum thickness and saturation of the separate-phase plume and/or elevated pressures. Such regions may be located in the vicinity of the injection well(s), as this will be the region of greatest pressure increase and greatest risk of fluid leakage.

- For projects with multiple Class VI injection wells, EPA recommends that the monitoring well system design address all injection wells together in a unified plan, even though the injection wells are permitted separately.

- The number of monitoring wells placed above the confining zone should be determined such that any leakage through the confining zone that may endanger a USDW will be detected in sufficient time to implement remedial measures. The number of monitoring wells above the confining zone may be determined based on a modeling and/or statistical analysis, which may be documented in the Testing and Monitoring Plan. Considerations that may be included in this analysis are the regional hydraulic gradient, flow paths, transmissivity, and baseline geochemistry.

- If approved by the UIC Program Director, previously existing wells perforated in the appropriate zone may be converted to use as monitoring wells for the GS project. These wells should be constructed to appropriate specifications, as discussed in Section 4.2.

- Revision of the site computational model and delineated AoR associated with AoR reevaluation may trigger a revision of the Testing and Monitoring Plan [40 CFR 146.90(j)]. Design of the monitoring well network, including steps taken to determine the placement of monitoring wells, should be reviewed during revision of the Testing and Monitoring Plan. If revision of the site computational model has resulted in changes to the size and shape of the AoR, monitoring well placement may require revision. See the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for discussion of AoR reevaluation; also see the *UIC Program Class VI Well Project Plan Development Guidance* for additional information on updating the Testing and Monitoring Plan.

4.1.3 Use of Phased Monitoring Well Installation

If approved by the UIC Program Director, monitoring wells may be installed on a phased basis during the lifetime of the project. Allowing for phased monitoring well installation will allow for monitoring well placement design to be changed based on monitoring results, new information about the project, and revision of the site computational model. It may also allow the use of newer and more protective monitoring well construction or materials. If phased monitoring well installation is allowed by the UIC Program Director, the phasing plan should be described and technically justified (e.g., the timing of monitoring well construction for each well) in detail in the Testing and Monitoring Plan. EPA recommends that planned monitoring wells that meet either of the following conditions be constructed prior to the commencement of injection:

- The wells are predicted to come into contact with the carbon dioxide plume (when direct monitoring for plume tracking is required) and/or with significantly elevated pressure within five years of commencement of injection operations.

- The wells are located in regions above the confining zone(s) overlying the portions of the injection zone where the separate-phase plume and/or pressure front is predicted to move within five years of commencement of injection operations.

The recommendation of five years is based upon the minimum required frequency for AoR reevaluations. However, another time frame, based on site-specific considerations, may be proposed and technically justified in the Testing and Monitoring Plan. EPA recommends that decisions regarding phased monitoring well installation and this duration be made in consultation with the UIC Program Director.

4.2 Monitoring Well Construction

The construction of monitoring wells is similar to the construction of injection or production wells in that all necessitate maintaining zonal isolation, employing good cementing practices, and selecting suitable well materials for the conditions with which they will come into contact. As with all wells, improperly constructed monitoring wells can serve as conduits for fluid movement, potentially endangering USDWs. This guidance document may be used to inform monitoring well construction if and where needed but does not address topics common to all types of well construction, instead focusing on topics that may be of particular interest or concern for constructing monitoring wells for GS. There are many documents and resources that provide more detailed descriptions of and recommendations for well construction, including the Class VI Rule injection well construction requirements at 40 CFR 146.86 and the *UIC Program Class VI Well Construction Guidance,* which discusses aspects of construction for Class VI injection wells. Other well construction resources include, but are not limited to, recommendations and guidelines published by the American Petroleum Institute (API) and ASTM. Furthermore, the *UIC Program Class VI Well Injection Depth Waivers Guidance* includes information on construction of wells in areas where the injection zone is located above the lowermost USDW. Topics that may be of particular concern for construction of monitoring wells at GS projects include materials, drilling techniques, well completion, zonal isolation, and recompletion of existing wells for use as monitoring wells. These are described below.

Materials

As with injection wells, monitoring well materials should be selected to withstand downhole conditions, including the fluids with which the materials may be expected to come into contact. Some factors that may be important to consider for the selection of monitoring well materials in GS projects include elevated pressures, temperatures, and stress from the rock column, depending on the depth of the wells. Wells for monitoring in the injection zone (if required by the UIC Program Director) may also encounter separate-phase carbon dioxide and carbon dioxide-rich fluids. These conditions can accelerate the degradation of well materials, including metals, cements, and plastics. Any monitoring equipment installed in the monitoring well will also need to be compatible with subsurface fluids with which they will come into contact. The *UIC Program Class VI Well Construction Guidance* contains specific information and references to other resources about materials that are compatible with carbon dioxide streams as well as native brines. It also discusses designing materials for the stresses likely to be encountered in the downhole environment. Wells completed in the injection zone will eventually be exposed to the pressure front as the plume enters the vicinity of the well. Although the pressure will be somewhat lower than the injection pressure, the well should be designed for pressures greater than the initial reservoir pressure.

Monitoring wells completed above the injection zone will likely face lower pressures than injection wells or monitoring wells in the injection zone, but they may still be exposed to similar conditions, e.g. contact with corrosive brines. Wells completed below the injection zone in the case of an injection depth waiver will likely be subjected to even higher temperatures and pressures than in the injection zone.

Well Drilling

Wells should be drilled in a manner that prevents movement of fluids between formations. In addition to allowing fluid movement, improper drilling can weaken or damage formations in the immediate vicinity of the well bore and lead to poor cement bonding, which can compromise the well after construction. Under- and over-pressurized zones present particular challenges in drilling and completing the well. An under-pressurized zone might be encountered when drilling through a depleted reservoir. Elevated pressure in an over-pressurized zone may be encountered if drilling is conducted to place a new monitoring well in the injection formation. For example, if an AoR reevaluation indicates that the plume has moved into an unanticipated area, it might be desirable to place a new monitoring well within the pressure front to better track the plume. In drilling such a well, care would be needed to prevent migration of fluids and/or carbon dioxide out of the injection zone.

The choice of appropriate drilling fluid (mud) is important for maintaining zonal isolation and for constructing a good well bore. It is important that the mud be appropriate for the subsurface conditions and allow fluid pressures to be properly maintained with respect to the formation. Depleted reservoirs may have formations or zones with poor integrity; an inappropriate mud may further degrade the rock, plug the pore space, and/or widen the well bore. High-pressure zones, on the other hand, necessitate the use of high-density mud to help maintain well control (i.e., control of high downhole pressure during drilling; Wray et al., 2009). Muds come in several classes or types, including water-based and oil-based fluids, those with and without solids, and high performance muds, which can include synthetics. It is possible to test the compatibility of the mud with the rock in the lab using core samples, although field experience is often also used (Brufatto et al., 2003).

During drilling, the pressure or weight of the mud needs to be correctly controlled. If the pressure/weight is too high, the mud will infiltrate the formation. It may potentially fracture the formation and can be difficult to remove, causing pore spaces to clog. If the pressure/weight is too low, native fluids from higher pressure zones can flow into the well bore, potentially causing the driller to lose control of the well. Infiltration of fluids from the formation into the well bore can cause delays in drilling and, with infiltration during well cementing, a poor cement job (poor bonding and/or development of channels in the cement) can result. If a well is being drilled through an injection zone, loss of control could result in movement of carbon dioxide out of the injection zone. The total pressure exerted against the formation is determined by a combination of mud density, height of the mud column, mud flow rate, friction losses, and pressure at the wellhead (Medley and Reynolds, 2006). Mud density is the easiest and most common way to alter mud weight and can be changed by altering the type of mud and through additives. Changes in drilling procedures or in drilling equipment may allow for controlling flow rate, pressure, and friction losses as well.

After drilling, the mud should be properly removed to clean and prepare the well bore so that a good bond and seal can be achieved between the cement and the casing and between the cement and the formation. The decision to not remove the mud may give rise to concerns regarding the quality of cementing achieved. If there is mud on the casing or formation, channels or microannuli could form in the cement and/or along the cement/casing contact or the cement/formation contact. These microannuli or channels could result in formation fluid or injectate movement outside the casing in the well bore. The UIC Program Director should be consulted for any decision regarding not removing the mud. The optimal strategy for mud removal depends upon borehole characteristics and the rheology of the drilling fluid (Brufatto et al., 2003). Options include displacing the mud using another fluid called a spacer, using metal attachments called scratchers attached to the casing and either rotating or reciprocating the casing, or using special chemicals such as acid washes (Shryock and Smith, 1981).

Well Completions

Well completion involves installing well tubular materials and other equipment to prepare the well for operation. Some equipment may be “dedicated” (permanently deployed), such as temperature gauges, pressure sensors, or geochemical sampling devices. Other monitoring equipment, such as crosswell sonar devices, mechanical integrity testing instruments, and logging equipment may be deployed periodically and will need adequate access to allow lowering into the well. The well diameter, any deviations of the well from vertical, and any significant curvature or bends in the well should be taken into consideration in combination with the size (e.g., diameter) and access needs of any monitoring equipment to be used. Other factors to consider in designing the monitoring well and planning for completion include the number and locations of perforated zones.

Most permanent downhole equipment requires cables or tubing that allow the transmission of collected data or samples to the surface. These can, however, interfere with other monitoring equipment lowered into the well. The cables and sample tubing can be coated and placed in metal or other hard conduits to protect against damage during installation. Another way to protect cables and sample tubing is to run them along the exterior of the tubing and hold them in place using clamps to prevent them from interfering with other equipment. In some rare cases, devices have been run along the outside of the casing and cemented in place. In this case, the sensors will need to be rugged and reliable because there is no way to replace them once they are installed. The typical lifespan of such devices, their anticipated durability under the conditions to which they will be exposed, and any potentially increased risk to well integrity should be considered when permanently deploying equipment, particularly along the exterior of the casing. Dual sensors (i.e., two sensors performing the same function, a primary and a backup) are also often used for this reason. EPA recommends that the use of external gauges be determined in consultation with the UIC Program Director, considering whether external gauges are a viable option for the given project and whether they pose an undue risk compared to downhole equipment. In some cases, aggressive downhole environments can interfere with sensor functioning. For example, fiber optic sensors have been known to drift in high temperature and pressure environments. Carbon- or metal-based coatings can sometimes prevent these problems

(Omotosho, 2004). Coatings can also protect cables from aggressive chemical environments as well as elevated temperature and pressure.

Because there is cement between the casing and the well bore to prevent fluid migration along the well bore, both the casing and cement will need to be perforated in areas where direct monitoring will occur so that the monitoring equipment can access the formation fluids to be sampled. Perforations are not required where equipment is installed on the exterior of the casing. However, geochemical sampling will always require perforations. The perforated intervals should be designed to monitor the appropriate zones and to be wholly located within the desired zones. Perforated zones should not cross injection zone/confining zone boundaries or confining layers, and the depths of perforated layers should be verified using logs to ensure they have been emplaced properly.

Zonal Isolation

In some cases, it may be desirable to monitor in multiple zones (e.g., the injection zone, the first permeable zone above the injection zone, and underlying formations if the project operates under an injection depth waiver). Using multiple completions in one well can minimize the number of penetrations through the confining layer. In this case, care is necessary to ensure proper zonal isolation during the entire life of the well.

Monitoring wells perforated in multiple zones should be equipped with packers to isolate the zones. The packers should be placed above and below each perforated zone to prevent flow of fluids between formations. The lowermost perforated zone, however, only needs a packer above the perforations. If there are abandoned perforations below the lowermost perforations in use, a bridge plug and cement plug should be set between the two sets of perforations to isolate the abandoned perforations. Packers should be made of materials capable of withstanding any corrosive effects from fluids with which they may come into contact, such as brine, wet carbon dioxide, supercritical carbon dioxide, or brine saturated with carbon dioxide. Packers will also need to be constructed to allow cables and tubing to pass through, and they should be pressure tested at the anticipated downhole pressures to ensure that they are sealed and will not allow fluid to pass through them.

One option to help preserve zonal isolation is to install equipment on the exterior of the casing and cement it in place. Running the required cables and tubes down the outside of the casing provides fewer openings in the packer and, therefore, fewer opportunities for leakage. However, the typical lifespan of such devices, their anticipated durability under the conditions they will experience, and any potentially increased risk to well integrity should be considered when permanently deploying equipment, particularly along the exterior of the casing. External deployment of fiber optic distributed temperature sensors and electric tomography equipment was done in a monitoring well in the CO_2SINK test project at Ketzin, Germany (Giese et al., 2009).

Recompletion of Existing Wells as Monitoring Wells

The cost of drilling new wells can make the use of existing wells as monitoring wells an attractive option. GS projects may involve the use of old production or injection wells for monitoring purposes. If such wells are recompleted for monitoring, there are special considerations necessary to ensure the integrity of the well and to prevent fluid migration along the borehole. These considerations include logging of the well (see the *UIC Program Class VI Well Construction Guidance*), determining the integrity of the cement and casing, conducting any necessary action to repair defects, and determining whether the existing well materials are adequate for the new function of the well.

The diameter of the hole, any deviations from vertical, and any significant curvature or bends in the well should be compared with the size of the proposed monitoring equipment. Existing well materials should be checked to ensure that they are compatible with fluids with which they will come into contact, such as carbon dioxide and carbon dioxide-rich brines if they are completed in the injection zone. Any flaws in the casing or cement will need to be repaired. Procedures for repairing defects in wells can be found in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*. Also, if monitoring is not necessary below the injection formation (i.e., in projects that do not involve an injection depth waiver), plugging the well below the injection formation is recommended.

4.3 Collection and Analysis of Ground Water Samples

<u>General Information</u>

The Class VI Rule requires ground water geochemical monitoring above the confining zone to detect changes in aqueous geochemistry that may result from fluid leakage out of the injection zone [40 CFR 146.90(d)]. The results of ground water monitoring will be compared to baseline geochemical data collected during site characterization [40 CFR 146.82(a)(6)] to obtain evidence of fluid movement that may impact USDWs. In addition, the owner or operator, if required by the UIC Program Director, may periodically collect fluid samples within the injection zone as a component of carbon dioxide plume tracking, as discussed in Section 5.

The proposed list of constituents, sampling methodology, sampling frequency, and the methods used for analyses for all constituents should be described and technically justified in the site-specific Testing and Monitoring Plan. EPA also recommends that a discussion of method sensitivities, as well as how deviations from planned project performance that may indicate an endangerment to a USDW will be identified, be included in the Testing and Monitoring Plan, as approved by the UIC Program Director.

At a minimum, EPA recommends that all wells initially be sampled on a quarterly basis for all relevant constituents during the injection phase. Alternatively, a project-specific frequency may be determined (e.g., based on variability in ground water chemistry) and approved by the UIC Program Director. Sampling frequency may be reduced based on project-specific benchmarks, such as generally stable conditions observed in several successive sampling rounds. Likewise, sample frequency may need to be increased if the results of monitoring indicate possible fluid leakage or endangerment of USDWs at a particular location. Certain constituents may be monitored near-continuously using dedicated downhole sensors, such as pH and specific conductivity.

Application

Sample Collection

Appropriate protocols consistent with existing EPA guidance (e.g., USEPA, 1991 and 1992) should be followed for collection of ground water samples to maintain sample integrity. Some aspects of commonly used ground water sampling protocols typical for shallow ground water investigations are also applicable to deep-well sampling at GS sites, while other protocols will need to be adapted to high-pressure, high-temperature conditions. This section briefly describes appropriate protocols for collection of ground water samples for GS projects. For further guidance, refer to existing EPA guidance (USEPA, 1991 and 1992; some portions of this section have been adopted from these existing documents).

Fluid collection from monitoring wells at depths typical of GS projects is complicated by elevated pressure and temperature of the sampled zone and the presence of multiphase fluids. Partitioning of gases (e.g., carbon dioxide dissolution into the aqueous phase) is temperature and pressure dependent. If not controlled, dissolved gases and supercritical fluids that exist at high pressures and temperatures found in the deep formations quickly exsolve or flash to gas as they are brought to the surface for analysis. Sampling systems have been developed that are lowered into the well bore using a wireline or slickline. These samplers maintain sample integrity by collecting samples at formation pressure and temperature, and allow collection and analysis of brine, dissolved gases, and supercritical fluids (Freifield et al., 2009; Boreham et al., 2011). Parameters such as temperature, density, pH, and conductivity can also be measured at near in situ conditions. If samples are not collected at the original, in situ conditions, additional measurements and reconstruction of the in situ conditions may be necessary during analysis and should be reported along with the results.

The U-tube sampling system is one example of a sampling system that has been developed specifically for deep well sampling, such as at GS sites. EPA notes that the U-tube sampling system may not be appropriate or feasible for all GS sites; however it has been used successfully in some test projects and is provided here as one example of a pertinent deep well sampling system (Boreham et al., 2011). A U-tube sampling system has been used to collect samples of reservoir fluids near in situ conditions for research-oriented GS projects at Cranfield, Mississippi, and Otway, Australia, as well as other sites. The U-tube sampler can collect large volumes of multiphase samples into high pressure cylinders for real-time field analysis and/or off-site laboratory analysis (Figure 4-2).

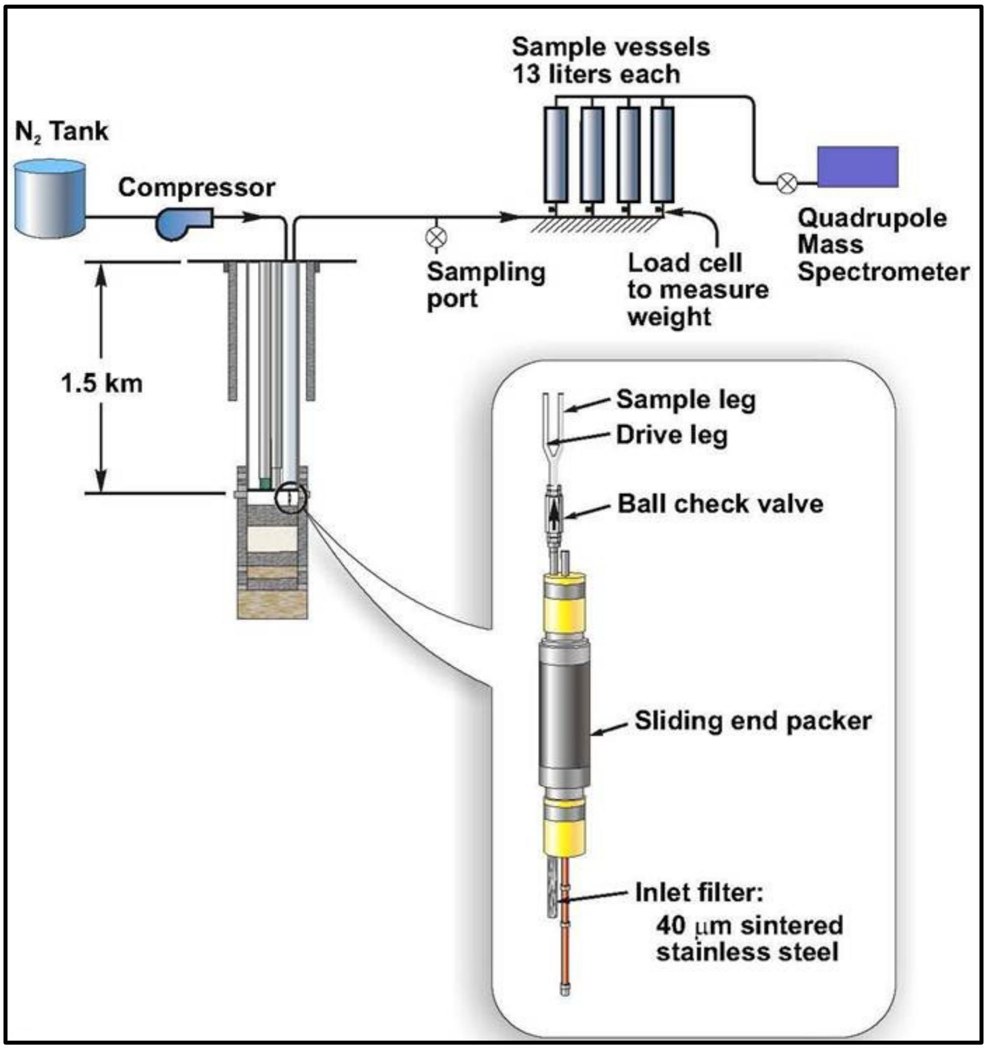

Figure 4-2. Schematic of the U-tube fluid sampling system (adapted from Freifeld et al., 2009; not to scale)

The general recommended protocol for deep well sampling at GS sites consists of the following steps:

1. Fluid level or pressure measurement. Prior to well purging and sample collection, it is important to measure and record the static fluid level and/or pressure in the well, along with bottomhole temperature. These measurements may be needed to estimate the amount of water to be purged prior to sample collection, and they may also be used for calculation of in situ pressure (Section 5.2). Pressure measurements may be obtained by application of a downhole pressure transducer (Section 5.2).

2. Decontaminating sample equipment. When dedicated equipment is not used for sampling (or well purging) or when dedicated equipment is stored outside of the well, the sampling equipment needs to be cleaned between each sampling event. See USEPA (1992) for recommended cleaning procedures, as well as manufacturer guidelines for the particular system used.

3. Well purging. Fluid that has been stored within the well bore is removed prior to sample collection to ensure that the sample is representative of the formation. See USEPA (1991) for guidance on how to determine the volume of fluid to be removed from the well bore prior to sample collection. During purging, EPA recommends that pH, specific conductance, and temperature be field measured periodically. EPA recommends that samples not be collected until the values of these parameters have stabilized. Use of passive (non-purge) sampling techniques (see, e.g., ITRC, 2006) should be described and technically justified in the Testing and Monitoring Plan and decided in consultation with the UIC Program Director.

4. In situ or field analyses. It is recommended that physically or chemically unstable analytes be measured in the field rather than in the laboratory. Examples include pH, redox potential, dissolved oxygen, temperature, and specific conductivity. An in-line flow cell, field kit, or downhole probes may be used for this analysis. All field and downhole equipment should be properly calibrated according to manufacturer specifications.

5. Sample collection and handling. The following recommended guidelines pertain to collection of ground water samples (for additional guidance, see USEPA, 1991 and 1992):

    a. Samples should be collected at tubing outlets as close as possible to the wellhead and placed into containers.

    b. Separate containers are typically used for different types of target analytes. Sample collection and containerization should be prioritized according to the volatility of the target analytes. The preferred order is: (1) volatile organics, (2) dissolved gases, including carbon dioxide, (3) semivolatile organics, (4) metals and cyanide, (5) major anions and cations, and (6) radionuclides.

    c. Samples should be transferred to sample containers in a controlled manner that minimizes sample agitation and aeration.

d. Ground water samples should be collected within a time period after the well is purged that ensures the quality of samples.

e. The rate at which the well is sampled should not exceed the rate at which the well was purged.

f. Generally, the only samples that should be filtered in the field include major anions and cations and total dissolved solids (TDS).

g. QA/QC procedures should be followed, as discussed below.

6. Sample containers and preservation. Refer to certified environmental laboratory protocols or USEPA (1991) for the appropriate sample container and preservation method depending on the analyte. Exposure of the samples to ambient air should be minimized.

7. Chain of custody and records management. A chain-of-custody procedure should be designed to allow the owner or operator to reconstruct how and under what circumstances the sample was collected, stored, and transported, including any problems encountered. The chain-of-custody procedure is intended to prevent misidentification of samples, to prevent tampering, and to allow easy tracking of possession.

8. Sample storage and transport. Transport should be planned so as not to exceed sample holding time before laboratory analysis and to maintain samples at necessary temperatures. Every effort should be made to inform the laboratory staff of the approximate time of arrival so that the most critical analytical determinations can be made within recommended holding periods.

Quality Assurance/Quality Control

The owner or operator is encouraged to follow accepted QA/QC procedures for collection and analysis of ground water samples (USEPA 1991 and 1992). The purpose of QA/QC samples is to ensure that the sampling protocol supports accurate laboratory analyses by eliminating cross contamination of samples and evaluating the repeatability of the laboratory analyses. It is recommended that the following QA/QC samples be analyzed, as a minimum, with each batch of collected samples (a batch should not exceed 20 samples):

- One field duplicate.
- One equipment rinsate, blank.
- One matrix spike (when appropriate for the analytical method).
- One trip blank (when analyzed constituents include volatile organics or dissolved gases).

All field QA/QC samples should be prepared exactly as other field samples with regard to sample volume, containers, and preservation. EPA recommends that the results of QA/QC samples be evaluated to ensure that data quality is within acceptable limits. The owner or operator may define acceptable data evaluation criteria in the Testing and Monitoring Plan. In addition, pursuant to 40 CFR 146.90(k), a Class VI permit application must contain a quality assurance and surveillance plan for all testing and monitoring requirements. For further information on EPA QA/QC procedures, including recommendations for preparing a Quality Assurance Project Plan (QAPP), readers are directed to guidance provided for projects funded or conducted by EPA (e.g., USEPA, 2002b).

Sample Analysis

Once the sample has been collected, it should be analyzed using an approved method for the constituents of interest. EPA recommends that fluid samples be monitored for, at a minimum, TDS, specific conductivity, temperature, pH, carbon dioxide, and density. In addition, the UIC Program Director may require regular monitoring of major anions and cations, select trace metals, tracers, hydrocarbons, and any other constituents identified by the owner or operator and/or the UIC Program Director. If impurities are present in the injectate (e.g., mercury, hydrogen sulfide), it is recommended that these be included in ground water monitoring (to detect concentrations beyond baseline) if there are indications of carbon dioxide or formation fluid displacement. Owners or operators of GS projects located in former or current oil and gas reservoirs may also monitor for hydrocarbons. EPA recommends that owners or operators of projects located in formations containing appreciable levels of arsenic or other metals that may be mobilized by the injection activity routinely monitor for those metals. However, the final list of constituents will be determined on a project-specific basis in consultation between the owner or operator and the UIC Program Director, using site-specific data obtained during site characterization (e.g., geology, geochemistry) and the composition of the injectate. As noted above, the constituents of interest should be described in the Testing and Monitoring Plan.

Examples of acceptable analytical methods for relevant parameters are provided in Table 4-1. It is recommended that an EPA-certified laboratory be used for all sample analysis. EPA's Office of Water implements the Drinking Water Laboratory Certification Program in partnership with EPA regional offices and states. Laboratories are certified by EPA or the state to analyze drinking water samples for compliance monitoring. In order to be certified by EPA, laboratories are required to successfully analyze proficiency testing samples annually, use approved methods, and successfully pass periodic on-site audits. Lists of certified laboratories are available through state lab certification programs. A listing of state lab certification programs can be found on EPA's website at http://water.epa.gov/scitech/drinkingwater/labcert/statecertification.cfm.

Table 4-1. Example analytical methods for some constituents in ground water. Note that additional or alternative methods may be available.

Monitoring Parameter	EPA Method(s)	ASTM Method(s)	Standard Method(s)
Carbon dioxide		D513	4500
Dissolved metals	200.8, 200.9, 7010	D3919-08	3112, 3113
Arsenic		D2972	3114, 3500
Mercury	245.1, 245.2	D3223	
Lead		D3559	3500
Hydrogen sulfide		D4658	4500

Monitoring Parameter	EPA Method(s)	ASTM Method(s)	Standard Method(s)
Petroleum hydrocarbons	8015C	D7678-11	
TDS		D5907	2540C
Major anions	300.1	D4327-03	4110, 4140
Major cations	6020A, 6020C, 700B	D5673-05, D4691-02(2007), D1976-07	3125, 3111
Fluid density		D1429-08	
Methane			6211

Interpretation

The analytical laboratory will provide the owner or operator with electronic and/or physical reports that provide all sample results in appropriate units (e.g., mg/L), method detection limits, the results of all QA/QC samples, and an evaluation of the resulting data quality. The results of field-measurement analysis (e.g., pH, temperature) are typically then compiled with the laboratory-supplied data. EPA recommends that the owner or operator maintain an electronic database of all monitoring well sample results that lists the resulting sample concentration and supplementary information, including sample data/time, analysis date/time, analytical detection limit, and data quality flags.

Prior to use for interpretation, collected data from monitoring wells are to be evaluated for quality and correctness. EPA recommends standard methods be used to ensure that sample results are consistent with the project data quality objectives. Interpretation of measured results also relies on comparison to baseline samples collected from the formation prior to injection, the results of the compatibility demonstration required at 40 CFR 146.82(c)(3), or samples collected upon construction of the monitoring well. See the *UIC Program Class VI Well Site Characterization Guidance* for discussion of baseline samples.

The primary objective of ground water monitoring is to detect geochemical changes that may be indicative of fluid leakage and migration. EPA recommends that the owner or operator evaluate the collected data relative to previously collected data and baseline data. Additionally, if the owner or operator conducts batch rock-water-carbon dioxide experiments or geochemical modeling, the collected data should be compared to those results as well (see the *UIC Program Class VI Well Site Characterization Guidance* for more information on these methods). Trends that may be indicative of fluid leakage include:

- Changing TDS: An increasing TDS trend may indicate that native brines have migrated from the injection zone, or an intervening zone, into the monitored zone. A change in the overall TDS trend may indicate fluid exchange between adjacent formations.

- Changing signature of major cations and anions: A change in the signature of dissolved ground water constituents in the monitored zone as compared to that of the injection zone or confining zone may indicate leakage. The anion/cation signature may be evaluated through the construction and use of ion diagrams, including Piper and Stiff diagrams (Figure 4-3).

- Increasing carbon dioxide concentration: An increase in the concentration of dissolved carbon dioxide may indicate leakage of the dissolved-phase plume into the monitoring zone. Increasing carbon dioxide concentrations may also be observed due to other factors, including increasing ground water recharge. These other factors may be evaluated to ascertain if the observed increasing carbon dioxide concentrations are due to migration from the injection zone.

- Decreasing pH: A decreasing pH trend may indicate migration of carbonic acid and other fluids into the monitoring zone. Similar to increasing carbon dioxide concentrations, other factors may be evaluated that would cause an observed decrease in pH.

- Increasing concentration of injectate impurities: An increase in the concentration of any impurities in the injectate (e.g., hydrogen sulfide) may be indicative of injectate migration into the monitoring zone.

- Increasing concentration of leached constituents: The presence of carbon dioxide may leach certain inorganics (e.g., lead, arsenic, iron, manganese) from the formation matrix due to lowered pH. Additionally, if petroleum hydrocarbons are present, carbon dioxide may increase the concentration of these constituents in the fluid phase. Increasing trends may be indicative of fluid migration.

- Increased reservoir pressure and/or static water levels (see Section 5.2).

Reduced sample fluid density, combined with the presence of separate-phase carbon dioxide in the sampled fluid, may also indicate the presence of the separate-phase plume at the monitoring location.

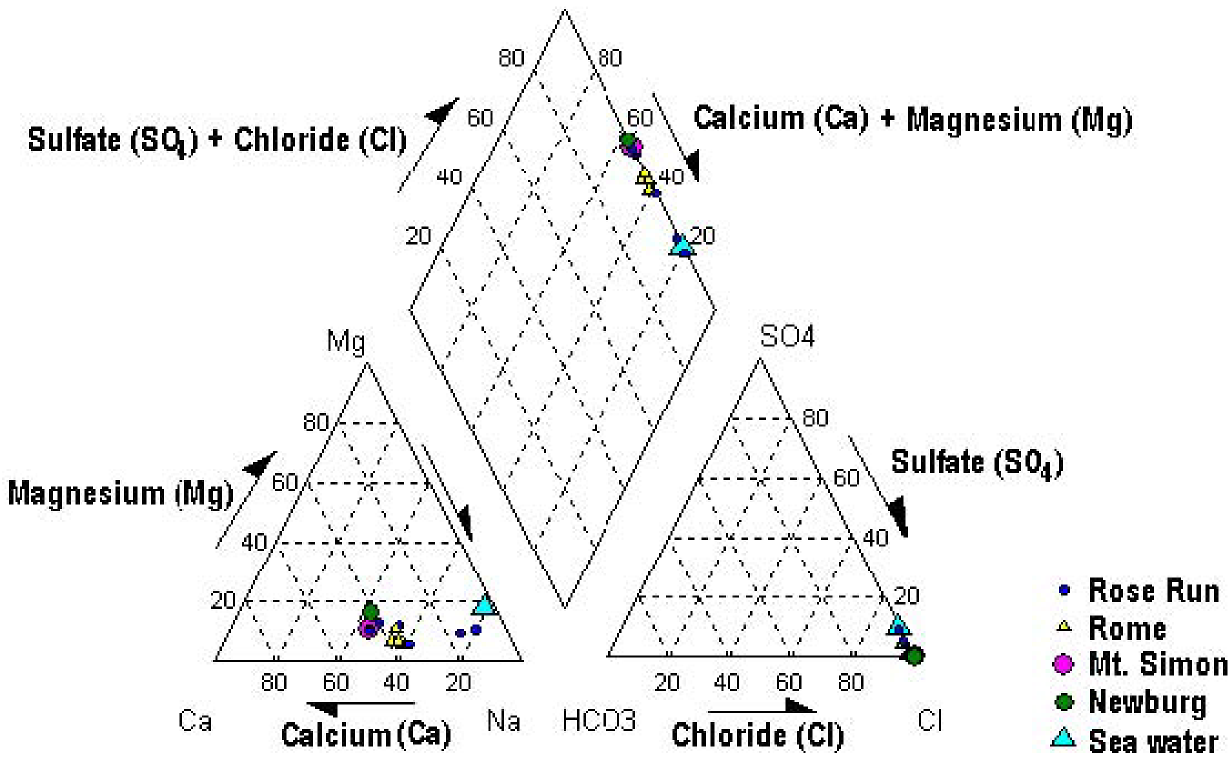

Figure 4-3. Example Piper diagram showing proportions of major ions for formations in Ohio and Kentucky, including potential target formations for GS (Battelle Memorial Institute, 2003).

Reporting and Evaluation

The owner or operator is required to submit the results of ground water monitoring in the semi-annual reports [40 CFR 146.91(a)(7)]. Data will be submitted in an electronic form directly to EPA, where they can then be accessed both by the UIC Program Director and other EPA offices. EPA recommends that the following information be submitted with all reports:

- The most recent database of all ground water monitoring results and QA/QC monitoring results.
- Original complete laboratory reports, including chain-of-custody records.
- Interpretation of any changing trends and evaluation of fluid leakage and migration. This may include graphs of relevant trends and interpretive diagrams (e.g., Piper diagrams).
- A map showing all monitoring wells, indicating those wells that are believed to be within the boundaries of the separate-phase or dissolved-phase carbon dioxide plumes.
- The date, time, location, and depth of all ground water sample collection and laboratory analysis of each sample.
- An evaluation of data quality for each sampling event.
- A description of all sampling equipment and laboratory analytical procedures used, noting any differences from protocols specified in the Testing and Monitoring Plan.
- Records of calibration of all field sampling instruments.
- Identification of data gaps, if any.
- Any identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs.

The UIC Program Director will evaluate the ground water monitoring data to independently assess data quality, constituent concentrations (including potential contaminants), and the resulting interpretation to determine if there are any indications of fluid leakage and/or plume migration and whether any action is necessary to protect USDWs.

5 Plume and Pressure-Front Tracking

Identification of the position of the injected carbon dioxide plume and the presence or absence of elevated pressure (i.e., the pressure front) is integral to protection of USDWs for GS projects. Regions overlying the separate-phase (i.e., liquid, gaseous, or supercritical) carbon dioxide plume and area of elevated pressure are at increased risk for potential fluid movement that may endanger a USDW. Because of this, monitoring the movement of the carbon dioxide plume and pressure front is necessary to identify potential risks to USDWs posed by carbon dioxide injection activities. Plume and pressure-front monitoring results also provide necessary data for comparison to and verification of model predictions, and they inform the reevaluation of the AoR (Figure 4-1). The owner or operator will use a site-specific, complementary suite of methods to track the position of the carbon dioxide plume and area of elevated pressure. Available methods for plume and pressure-front tracking include: (1) in situ fluid pressure monitoring; (2) indirect geophysical monitoring; (3) ground water geochemical monitoring; and (4) computational modeling. These methods must be described by the owner or operator in the Testing and Monitoring Plan that is approved by the UIC Program Director [40 CFR 146.90].

EPA recognizes that these four methods include a range of specific technologies that may be used to monitor and track a carbon dioxide plume and pressure front. Therefore, in the Class VI Rule, EPA does not prescribe specific technologies (e.g., geophysical techniques, water sampling apparatuses) that must be used to achieve these goals. The suite of methodologies used will be site specific and vary based on project details, but it must include at least one direct method [40 CFR 146.90(g)(1)] and an indirect method, unless the UIC Program Director determines indirect methods are not applicable [40 CFR 146.90(g)(2)]. Additionally, the flexibility of these requirements allows for deployment of new technologies as they are developed. This section discusses available methods that can be used for tracking the carbon dioxide plume and pressure front. Computational modeling is discussed in detail in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*.

The various methods for identification of the location of carbon dioxide, mobilized fluids, and elevated pressure provide complementary types of data. Direct pressure monitoring (see Section 5.2) and ground water geochemical monitoring (see Section 5.4) do not rely on theoretical assumptions or data processing to the extent of other methods (e.g., indirect geophysical methods). However, these two types of monitoring only provide point measurements (i.e., measurements at discrete locations). Indirect geophysical monitoring, discussed in Section 5.3, provides broad, non-point measurements, but data collection requires extensive pre-processing and in some cases results may be ambiguous compared to direct monitoring. Computational modeling (discussed in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*) provides a prediction of future conditions, but these predictions rely on simplifying assumptions and are prone to uncertainty. The most comprehensive understanding of plume and pressure-front behavior will follow from an integrated interpretation of information collected from a combination of these methods. For example, interpretation of geophysical monitoring results is improved by consideration of available monitoring well data during data processing. The predictive capability of computational models is improved by model calibration to ground water geochemistry, pressure, and geophysical monitoring data. For Class VI projects, this process is conducted during AoR reevaluation.

5.1 Class VI Rule Requirements Regarding Plume and Pressure-Front Tracking

The Class VI Rule requires the use of "direct" methods for tracking the presence or absence of elevated pressure (e.g., the pressure front) within the injection zone [40 CFR 146.90(g)(1)]. The Class VI Rule also requires the use of indirect geophysical techniques for the purpose of tracking the extent of the carbon dioxide plume, unless the UIC Program Director determines, based on site specific geology, that such methods are not appropriate [40 CFR 146.90(g)(2)]. As discussed below, on a site-specific basis, where the UIC Program Director determines that indirect methods are not appropriate, he or she may require the use of direct methods for the purpose of tracking the carbon dioxide plume by using monitoring wells that are perforated within the injection zone. Table 5-1 provides a summary of the Class VI Rule monitoring requirements related to tracking the position of the carbon dioxide plume and pressure front.

Table 5-1. Summary of Class VI Rule requirements and recommendations for identifying the position of the carbon dioxide plume and associated pressure front.

Technology	Description	Class VI Rule	
		Requirement	Citation
Direct pressure monitoring	Measurement of in situ fluid pressure that may be achieved using transducers placed within monitoring wells in the injection zone, behind casing gauges, or through direct measurement of fluid depth through a perforation (see Section 5.2)	Required to track the presence or absence of elevated pressure within the injection zone	40 CFR 146.90(g)(1)
Indirect geophysical monitoring	Seismic, electrical, gravity, or electromagnetic techniques (see Section 5.3)	Required to track the presence or absence of elevated pressure within the injection zone and the extent of the carbon dioxide plume, unless the UIC Program Director determines that such methods are not appropriate	40 CFR 146.90(g)(2)
Direct carbon dioxide plume monitoring	Use of monitoring wells in the injection zone to substantiate the presence or absence of carbon dioxide by geochemical methods (see Section 5.4)	Required to track the extent of the carbon dioxide plume if the UIC Program Director determines that indirect methods are not appropriate	40 CFR 146.90(g)(1)
Computational modeling	Informing the development of field monitoring strategies and incorporation of measured data into a comprehensive mathematical model of the site	Computational modeling is required as a component of AoR delineation and reevaluation	40 CFR 146.84

5.2 Direct Pressure-Front Tracking

The Class VI Rule requires that fluid pressure be directly monitored within the injection zone [40 CFR 146.90(g)(1)]. Owners or operators are also required to supplement the direct monitoring with indirect, geophysical techniques unless the UIC Program Director determines, based on site-specific geology, that such methods are not appropriate [40 CFR 146.90(g)(2)]. Pressure monitoring in the injection zone is an integral part of overall GS monitoring because increased pressure within the injection zone is the primary driver for fluid movement that may endanger USDWs. Furthermore, pressure measurements will also inform AoR reevaluation.

Direct pressure monitoring provides measurements of formation pressure and supports tracking the migration of the pressure front [40 CFR 146.90(g)(1)]. In this context, the term "direct methods" pertains to the in situ measurement of fluid pressure, which may be achieved using transducers placed in the injection zone behind casing gauges, or by direct measurement of fluid depth in the well. Direct measurements of pressure also include measurements made at the wellhead. These measurements do not rely on theoretical assumptions or data processing; however, they only provide point measurements (i.e., measurements at discrete locations). Therefore, where applicable, the Class VI Rule also requires indirect geophysical monitoring (discussed in Section 5.3), which provides non-point measurements that can provide a broad view of the movement and extent of the carbon dioxide plume and pressure front. EPA requires that the strategy and methodologies selected for pressure-front monitoring be described in the site-specific Testing and Monitoring Plan, which is approved by the UIC Program Director [40 CFR 146.90].

EPA recommends that owners or operators also monitor pressure above the confining zone(s); these data may also be used to detect potential leakage through the confining zone(s). The pressure front is defined as the zone where the pressure differential is sufficient to cause the movement of injected fluids or formation fluids from the injection zone into a USDW. This determination of the pressure front is based on existing standard practices for other well classes in the UIC Program and involves calculation of a threshold reservoir pressure as described in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*. The value of threshold reservoir pressure that defines the pressure front may be calculated based on static pressure within the injection zone and the lowermost USDW, as well as the elevations of both zones by determining the pressure within the injection zone that is great enough to force fluids from the injection zone through a hypothetical open conduit into any overlying USDW. The *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* includes an illustrative example of this calculation.

The proposed pressure monitoring frequency for all wells must be described and technically justified to meet the requirements for the Testing and Monitoring Plan at 40 CFR 146.90. At a minimum, EPA recommends that all wells be monitored for pressure changes on a monthly basis during the injection phase. Monitoring frequency may need to be increased if the results of monitoring indicate pressure increases greater than modeling predictions or indicate fluid leakage. For many GS projects, pressure may be monitored nearly continuously by the use of dedicated downhole devices. EPA notes that it is important to use and calibrate these devices according to the manufacturer's specifications and standard (e.g., ASTM) guidance.

<u>Application</u>

At GS sites, direct pressure monitoring may be achieved using downhole transducers. Direct pressure monitoring may also include measurements made at the wellhead. In some cases, fluid pressure may be inferred from measurements of the depth to fluid. Measurement of the depth to fluid in the well from the surface can be used to determine bottomhole pressure based on knowledge of the density of the fluid and the vertical distance between the perforated interval and wellhead measurement. Fluid-level measurements may be obtained by use of an electric depth gauge lowered on a wireline.

Considerations related to monitoring well placement and the design of the monitoring well network for tracking the pressure front are similar to those for ground water geochemical monitoring above the confining zone, as discussed in Section 4. Geochemical monitoring above the confining zone and direct monitoring of pressure serve to achieve complementary goals for ensuring USDW protection, by identifying potential leakage through the confining zone and identifying elevated pressure zones in the injection zone, respectively. Therefore, EPA recommends that, to minimize the number of monitoring wells deployed, owners or operators consider an overall strategy to incorporate both types of monitoring when designing the monitoring well network. Similar to the conditions recommended in Section 4 for geochemical monitoring above the confining zone, EPA recommends the following considerations for the design of the monitoring well network for pressure-front tracking:

- Wells used to track the migration of the pressure front should be designed to allow in situ measurements within the injection zone. EPA recommends that pressure measurements be conducted in wells perforated at stratigraphically equivalent depth intervals to the depth of the injection zone.

- For projects with a separate-phase plume and/or pressure front predicted to move in a specific direction (e.g., due to formation dip), wells should be primarily placed in the predicted down-gradient direction. However, at least one up-gradient well is recommended.

- Well placement should be based on the predicted rate of migration of the separate-phase plume and/or pressure front, according to the results of computational modeling and taking into consideration associated uncertainties.

- The number of monitoring wells placed within the injection zone should be determined such that changes in the area of elevated pressure may be tracked sufficiently to detect any pressure increase that differs from modeled predictions. The determination of the number of injection zone wells may be based on a modeling and/or statistical analysis, which should be documented in the Testing and Monitoring Plan.

Interpretation

Fluid-level data obtained from electric gauges lowered into the well on a wireline will consist of depth to fluid measurements, in units of feet or meters. These measurements will be converted to values of the elevation of the fluid column relative to a common datum, most commonly mean sea level. This is achieved from the following equation:

$$FL = MPE - DTF \quad [1]$$

where *FL* is the elevation of the top of the fluid column within the well, *MPE* refers to the surveyed measurement point elevation at the wellhead, and *DTF* refers to the measured depth to fluid. Data collected from downhole pressure transducers will consist of pressure readings (in units of psi or Pa). With knowledge of the elevation of the pressure transducer measurement device, *FL* may be obtained using the following equation:

$$FL = PTE + \frac{P_t}{\rho g} \qquad [2]$$

where *PTE* refers to the known elevation of the pressure transducer (measured when the pressure transducer was emplaced), P_t refers to the measured pressure at the transducer, ρ refers to the density of fluid within the well, and *g* refers to the acceleration due to gravity. Lastly, the *FL* within the well is used to calculate the pressure (*P*) at the depth of the perforated interval of the well using the following equation:

$$P = (FL - Z) \cdot \rho g \qquad [3]$$

where *Z* is the elevation of the center of the perforated interval of the well. Note that temperature corrections may be necessary for the fluid density term used in these calculations. If using data from a pressure transducer set at the center of the perforated interval of the well, the above calculations are unnecessary, and the measured pressure is representative of the in situ pressure.

Once the in situ pressure at all wells has been determined, temporal changes should be analyzed by comparing the new data to previously collected data. EPA recommends that the owner or operator produce and interpret time-series graphs for each well, taking into consideration the injection rate and well location. An example plot of the temporal trend of measured pressure for an injection and monitoring well are presented in Figure 5-1. It is recommended that spatial patterns be analyzed by constructing maps that present contours of pressure and/or hydraulic head. Increases in pressure in wells above the confining zone (if such monitoring is performed) may be indicative of fluid leakage, and measurements should be used to complement fluid monitoring data in assessing leakage. It is recommended that increases in pressure within the injection zone be compared to modeling predictions to determine if the AoR is consistent with monitoring results. Pressure increases at a monitoring well location greater than predicted by the current site AoR model, or increases at a greater rate, may indicate that the model needs to be revised. In this case, the UIC Program Director should be consulted to determine whether an AoR reevaluation is necessary.

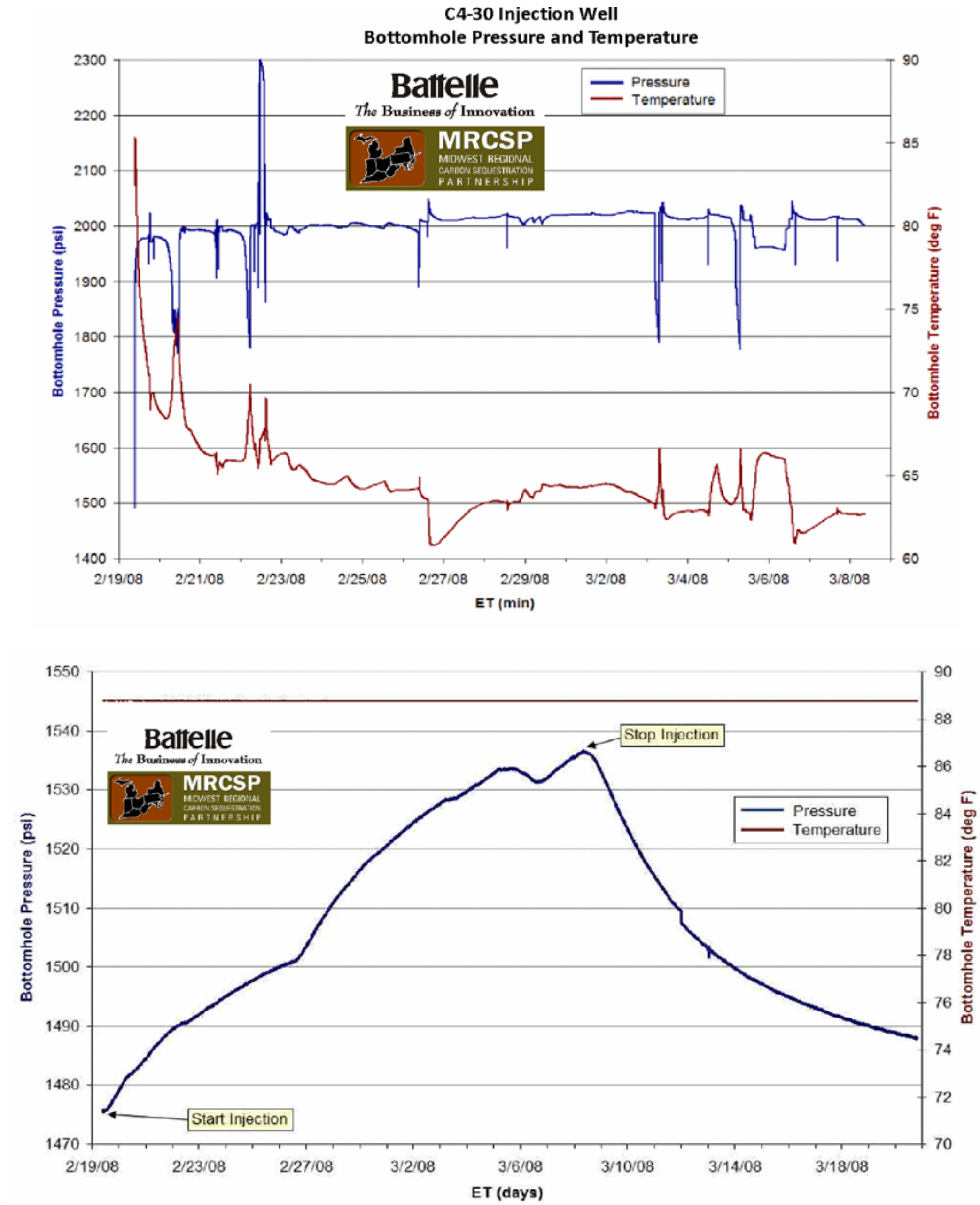

Figure 5-1. Example of temporal plots showing change in pressure and temperature at an injection well (above) and monitoring well (below) during initial testing at the MRCSP Michigan Basin Validation Test (images provided by Battelle Memorial Institute). Images are intended for example purposes only; note that axis scales on the two graphs are not identical.

Reporting and Evaluation

The Class VI Rule requires that the owner or operator submit the results of pressure monitoring as part of the semi-annual reports [40 CFR 146.91(a)(7)]. Data will be submitted in an electronic form directly to EPA, where they can then be accessed both by the UIC Program Director and EPA offices. EPA recommends that the following information regarding direct pressure-front monitoring be submitted with all reports:

- Raw pressure data, interpreted data where pressure is calculated at the depth of the injection zone, location and depth of all readings (e.g., depth to the perforated intervals), and fluid temperature and density measurements.

- If using pressure transducers, records of the most recent calibration or verification of the measurement instrument.

- Records of the surveying of wellhead and measurement point elevations.

- Interpretation of data using supplemental maps and graphs, such as time-series graphs, pressure contour maps, and correlations between injection rate and pressure response.

- Comparison of measured pressures and model predictions for the same time period after commencement of injection.

- Geomechanical data and/or quantification of any fluid withdrawal or injection that would impact measured pressure monitoring data.

- Identification of data gaps, if any.

- Any identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs.

- Presentation, synthesis, and interpretation of the entire historical data set, including an assessment of whether pressure data are indicative of fluid leakage.

The UIC Program Director will also evaluate the submitted data to independently assess if pressure increases within the injection zone are consistent with predictive modeling, as well as whether pressure measurements from wells above the confining zone are indicative of fluid leakage. EPA notes that the owner or operator is required to report any permit noncompliance which may cause fluid migration into or between USDWs within 24 hours [40 CFR 146.91(c)(2)].

5.3 Plume and Pressure-Front Tracking Using Indirect Geophysical Techniques

The Class VI Rule requires the use of indirect (i.e., geophysical) methods to supplement the direct monitoring of the pressure front and to monitor the carbon dioxide plume unless the UIC Program Director determines, based on site-specific considerations, that indirect methods are not suitable [40 CFR146.90(g)(2)]. This section will discuss the use of geophysical methods, which can be used to image the carbon dioxide plume and, in the case of seismic profiling, may also be used to derive fluid pressure. Geophysical methods include several technologies used to indirectly monitor subsurface conditions over a relatively large area using surface and/or several well bore measurements. These techniques typically work by initiating the propagation of a signal (e.g., seismic, electromagnetic) and measuring the reflection or transmission of that signal. Resulting data can be processed and interpolated to provide estimates of fluid phase-state (e.g., aqueous versus supercritical) and fluid pressure (if seismic profiling is used). Geophysical techniques provide advantages over use of monitoring wells in that results are interpreted to provide an understanding of the position of the carbon dioxide plume over a broad area, whereas monitoring wells only provide discrete point measurements. Geophysical techniques have been widely deployed in petroleum exploration and monitoring and in early GS projects (e.g., USDOE NETL, 2009a). Using geophysical techniques also does not necessitate the drilling of a monitoring well, which would be an artificial penetration and a potential conduit for fluid movement.

There are three main types of geophysical methods that can be used for monitoring at GS projects: seismic, gravity, and electrical. In addition to plume and pressure-front tracking, geophysical methods are also used for site characterization (see the *UIC Program Class VI Well Site Characterization Guidance*). Baseline geophysical surveys conducted during site characterization are necessary for comparison, to assess changes in the subsurface induced by the injection operation. For detailed information regarding conducting baseline geophysical surveys, see the *UIC Program Class VI Well Site Characterization Guidance*. This section focuses on those methods applicable to surveys collected during the injection phase.

As described in Section 1.3, in a preliminary evaluation of GS monitoring technologies, USDOE NETL (2009a) assessed several technologies based on application, function, and stage of development. In this evaluation, technologies were rated as primary, secondary, or potential in their ability to provide useful information for subsurface monitoring of injection well integrity and the fate of the injectate and mobilized fluids.

The primary technologies identified by USDOE NETL (2009a) included some geophysical techniques discussed in this document for plume and pressure-front tracking. Among these, certain seismic methods were rated as secondary technologies, and the remaining methods, as discussed below, were considered to be potential technologies that have not yet been proven in commercial-scale projects. Before using any technology considered “potential” in the USDOE NETL evaluation system, EPA recommends that the owner or operator consult with the UIC Program Director (i.e., during the development of the Testing and Monitoring Plan). In addition to geophysical techniques, the USDOE NETL evaluation also discusses certain potential technologies, such as tiltmeters, synthetic aperture radar, and interferometric synthetic aperture radar (InSAR), which can indicate crustal deformation associated with elevated pressure due to carbon dioxide injection. These methods are at an earlier stage of development in their applicability to GS and are not discussed in detail in this guidance document. The reader is referred to USDOE NETL (2009a) and references therein for more information, and owners or operators may consider use of these techniques in consultation with the UIC Program Director. If taken in proper time lapse, some geophysical well logging methods (e.g., pulsed neutron) can also be used for tracking of the plume. A well-logging program may be used to detect changes in fluid saturation near the well bore and identify plume thickness. For further information on these logs, see the *UIC Program Class VI Well Site Characterization Guidance.*

In addition to the advantages and disadvantages common to most geophysical surveys (see the *UIC Program Class VI Well Site Characterization Guidance*), an additional challenge facing deployment of these technologies for plume and pressure-front monitoring is ensuring proper time-lapse (also called four-dimensional) deployment. To facilitate comparison between sequential surveys, it is essential that each survey is carefully georeferenced. Changes in subsurface conditions between surveys can be linked to changes in the location of the plume or pressure front only if the exact location of every survey is known. Otherwise, anomalies between surveys may be the result of comparing two different subsurface locations. Installing infrastructure such as survey markers or measurement stations is one method to ensure repeatability. A permanent deployment array is another method that can limit positioning error between repeat surveys.

Changes in near-surface conditions may also need to be taken into consideration. For example, research suggests that near-surface conditions such as soil water saturation may have a large effect on comparability between seismic surveys (Urosevic et al., 2007). If possible, near-surface variables should be limited by taking repeat surveys during periods of similar soil water saturation and other near-surface variables.

Because the information gathered from geophysical surveys is indirect and subject to processing that can introduce error, it is recommended that the results of any survey also be compared to other site data (e.g., monitoring well data) where available. EPA recommends that the Testing and Monitoring Plan describe any information that may be used to improve or support the repeatability of the geophysical methods and associated data processing (e.g., selection of sources, spacing, depth, optimization techniques, removal of background signal). Importantly, quantification of the limits and uncertainties in the detection capabilities of the chosen methods should be described in the Testing and Monitoring Plan.

5.3.1 Seismic Methods

<u>General Information</u>

Seismic profiling methods measure the arrival of seismic waves that travel through the earth. Seismic surveys can be used to track the separate-phase plume and the migration of formation fluids. These methods are generally recognized to have the highest resolution of all geophysical remote imaging techniques in a variety of geologic settings (Benson and Myer, 2002). A large variety of seismic techniques are available with different capabilities that can be targeted to deliver greater detail near the borehole, between wells, or in another targeted location. Because seismic monitoring is an established method, data collection and processing methods are well known, numerous, and can be easily tailored to site-specific conditions.

However, seismic imaging may be difficult in certain types of geologic formations including salts, basalts, coal seams, carbonates, and non-sedimentary units (Cooper, 2009; Hyne, 2001). If such lithologies are present, seismic data may need to be supplemented with additional data to ensure accuracy (e.g., geochemical monitoring in the injection zone for plume tracking). Seismic methods also: perform poorly for detecting carbon dioxide in depleted gas reservoirs and do not work well for imaging through shallow, dry natural gas reservoirs; can be affected by anthropogenic noise; are hard to deploy in populated areas; and can result in widely varying data quality.

Of the seismic methods, two- and three-dimensional surface surveys, including time-lapse surveys, and microseismic surveys are considered secondary technologies according to the USDOE NETL evaluation system. Vertical seismic profiling (VSP) and crosswell seismic methods are considered to be potential monitoring technologies (USDOE NETL, 2009a).

<u>Application</u>

All seismic methods rely on different subsurface materials having different seismic velocities and varying likelihoods of reflecting seismic waves based on characteristics such as fluid saturation and compaction. For example, seismic waves travel much more slowly through carbon dioxide-saturated rock because supercritical carbon dioxide is less dense and more compressible than aqueous fluids. Therefore, depending on the material, both the transmission time and the number of reflections vary. In some methods, the recorded time is the two-way travel time (from the source to the subsurface reflector and back to the receiver).

Data collection procedures for specific seismic methods vary widely, but there are several common fundamentals. All methods require a natural or anthropogenic source of seismic waves, which are detected by receivers (geophones or hydrophones) that log information about the wave. Sources and receivers can either be on the surface (surface methods) or in the subsurface (borehole methods). Seismic sources include natural earthquakes (including microseismic events as small as -3 magnitude), explosives, vibroseis trucks, air guns, and piezoelectric sources.

Surface seismic methods (including two- and three-dimensional seismic) are suitable for plume and pressure-front monitoring because they can image a large area and will likely be able to capture the entire extent of the plume or pressure front. Borehole methods are only able to verify if the plume has reached a certain point. Additionally, if the carbon dioxide plume develops narrow protrusions (i.e., fingers) or migrates along faults or other narrow linear features, borehole methods may fail to detect the movement of the carbon dioxide.

Borehole methods (e.g., crosswell, VSP, borehole microseismic) produce higher-resolution images than surface methods because seismic waves only pass through weathered surface horizons once, minimizing distortion. The higher resolution provided by these techniques may be useful where the carbon dioxide plume is predicted to be thin or complex in shape. Additionally, because wells are stationary, repeatability and georeferencing between surveys in a time-lapse sequence is not a problem. However, borehole methods are less than ideal for plume and pressure-front monitoring because they can only image a small region close to the well bore. Borehole seismic methods may use monitoring wells installed for ground water monitoring.

Two-dimensional seismic surveys are used to collect an image that represents a vertical cross section though the earth. Data are collected by a linear arrangement of geophones and seismic sources positioned along the surface trace of the slice. Two-dimensional seismic surveys were considered state of the art through the 1980s and are still commonly used today. Because of their linear nature, two-dimensional surveys do not image features that are out-of-plane. For this reason, two-dimensional surveys are less applicable for plume and pressure-front tracking compared to three-dimensional surveys.

Three-dimensional seismic surveys use a grid of multiple sources and receivers to generate a mix of source-receiver combinations. The most basic arrangement is a linear array of geophones and a linear array of seismic sources intersecting at a right angle (McFarland, 2009). The resulting data set represents signal data received from a variety of sources, angles, and distances at each geophone, eliminating problems caused by out-of-plane features. Advanced computer processing is able to account for these geometries and create a three-dimensional model of the subsurface. Three-dimensional seismic methods replaced two-dimensional seismic methods as the state-of-the-art standard in the 1990s. Resolution and spatial coverage can be high, and, under the right conditions, this method is ideal for imaging carbon dioxide in the subsurface.

Time-lapse seismic surveys (also referred to as four-dimensional surveys) generally consist of the periodic repetition of three-dimensional surveys to image changes to the subsurface over time. The exact same methodology needs to be used in the same locations during the repeated surveys in order for data to be comparable. Performing a time-series survey allows subsurface features such as fluid saturation to be tracked over time. The ability to accurately determine the exact position of individual seismic surveys has been assumed to exert the strongest influence on the overall quality of the time-lapse composite. However, research at the Otway project in Australia (Urosevic et al., 2007) suggests that near-surface conditions such as soil saturation may also have a significant effect on seismic repeatability and comparability between surveys. An example of tracking the evolution of a carbon-dioxide plume in the subsurface using time-lapse seismic surveys is provided in Figure 5-2.

Vertical seismic profiles or VSPs are the most common borehole seismic method. They obtain an image of the plane between the well bore and the surface. A VSP is conducted with one component located on the surface (usually the source) and the remaining component placed downhole (Figure 5-3). The surface component may be stationary or moved during the survey.

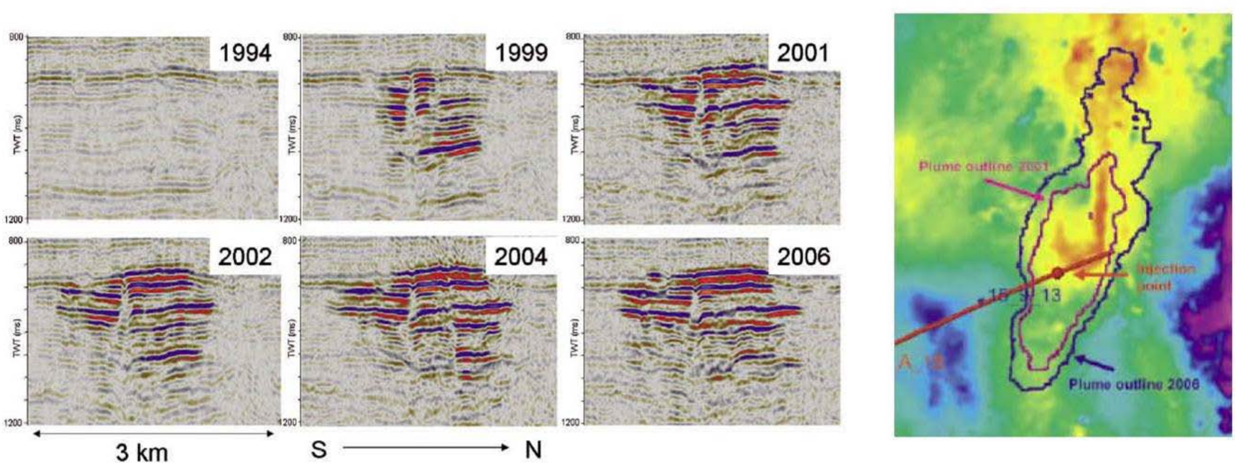

Figure 5-2. Time-lapse three-dimensional seismic surveys were used to track the spread of the carbon dioxide plume at the Sleipner project in the North Sea (Arts et al., 2008). Figure shows a surface view of the plume (right) and slices through the plume (left). Images from European Association of Geoscientists & Engineers (EAGE)/First Break; reprinted with permission.

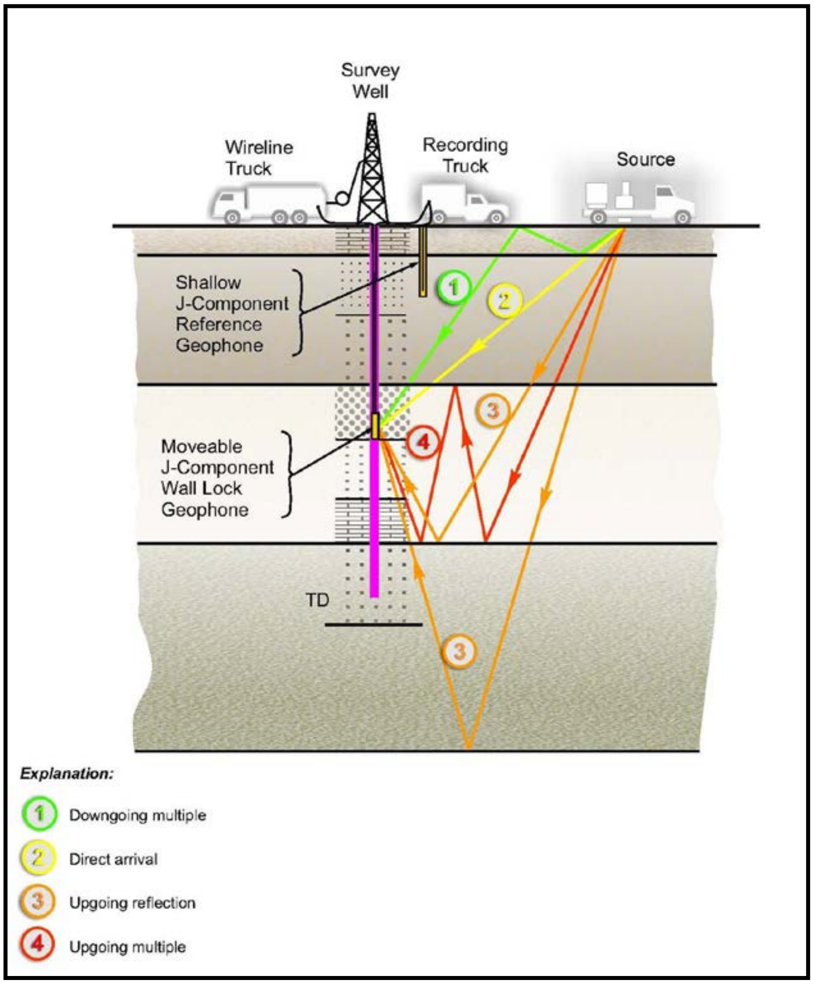

Figure 5-3. Schematic of the VSP process (adapted from Sah, 2003).

VSPs can be conducted on land or at sea in vertical or deviated wells to a depth of at least 3,000 m (Balch et al., 1982). The source may be directly adjacent to the borehole or located at a fixed distance away (an "offset" VSP). A "walkaway" VSP results when the source is moved away from the well over the course of the survey. VSPs provide valuable information about the subsurface geologic structure and seismic anisotropy; in addition, increased resolution compared to surface seismic methods allows VSPs to detect thin plumes.

Crosswell seismic methods deploy sources and receivers in several different wells, producing a survey that images the plane between the wells. Equipment is generally deployed in dedicated monitoring wells not more than 500 m apart (Hoversten et al., 2002), although deployment down active injection wells is also possible (Daley et al., 2007). A seismic source is deployed down one well and seismic recorders are deployed down additional wells. A typical problem with crosswell surveys is difficulty in matching profiles taken at a common well. These failures often result from processing techniques that assume simple geology and vertical wells and that fail to allow for out-of-plane structure. However, newer data processing techniques have made progress at remedying these problems. Crosswell surveys using several wells are now able to generate three-dimensional crosswell surveys (Washbourne and Bube, 1998). Multiple wells are needed for crosswell seismic surveys, potentially limiting deployment in regions with few subsurface penetrations. This may also limit the usefulness of crosswell seismic for purposes of plume tracking as a project matures, if the plume has expanded beyond the area between the observation wells.

Borehole microseismic profiling uses a string of geophones deployed down a monitoring well for weeks to months, or permanently (to avoid placement errors). Microseismic events that occur naturally during that time (typically on the order of magnitude -3 to -1) are detected by these geophones. Because this method does not use an actively controlled source of seismic energy, it is considered to be a passive-source method. On average, microseismic events can be detected up to 1 km from the well (Downie et al., 2009). After collection, the hypocenters of the microseismic events are plotted onto a three-dimensional subsurface projection to image subsurface areas undergoing deformation. Borehole seismicity profiling may not be appropriate for imaging fluids, and therefore it may not be useful for plume tracking at present. However, the method may be useful for tracking the pressure front because changes in seismicity are often related to changes in subsurface pressure.

Interpretation

Seismic surveys produce a two-dimensional cross-section or a three-dimensional image of the subsurface. However, after collection, seismic data require extensive post-collection processing to convert the data into interpretable images. For example, due to source/receiver geometry and physics, uncorrected seismic reflections from dipping layers appear in the wrong location and at an incorrect dip. Layers that terminate against a fault may appear to cross the fault. Depending upon the method, more than 30 different filtering and processing steps can be applied. These data processing steps inherently introduce error and uncertainty, and direct data collected from monitoring wells may be used to constrain data processing and improve data confidence.

Resolution varies greatly depending on the seismic technique used. Generally, crosswell seismic has the best resolution, followed by VSP, then surface seismic methods. Three-dimensional methods usually have higher resolution than two-dimensional methods. However, there is a tradeoff between resolution and depth: high-frequency waves yield a greater resolution because the wavelength is smaller, but they cannot penetrate as deeply. Traditional rules of thumb limit the resolution to between one-quarter and one-eighth of the wavelength (Rubin and Hubbard, 2005; Wilson and Monea, 2004). It is generally recognized that seismic methods have the best resolution of all geophysical methods (Benson and Myer, 2002).

Although seismic waves are sensitive to low saturations of carbon dioxide, the relationship between saturation and sensitivity is not linear (IEA, 2006). Therefore, while it is relatively easy to determine if separate-phase carbon dioxide is present using seismic methods, it is much harder to constrain the volume present on a seismic survey. Additionally, temperature uncertainties in the reservoir can introduce large errors into carbon dioxide volume calculations because temperature has a strong effect on carbon dioxide phase and volume. The range of carbon dioxide saturation that can be imaged will depend upon several site-specific conditions. Lumley et al. (2008) have discussed this issue and draw some general conclusions: (1) seismic techniques are an excellent monitoring tool for detecting areas with and without carbon dioxide (i.e., with a bird's eye view); (2) in typical situations, seismic techniques may or may not be able to reasonably image the three-dimensional distribution of carbon dioxide; and (3) it will be extremely challenging to quantitatively invert seismic data to accurately estimate carbon dioxide saturations and injected volumes of carbon dioxide due to fundamental physical limitations.

Seismic surveys can be processed to yield subsurface pressure data and used to track the pressure front. Any seismic survey that yields an accurate acoustic seismic velocity can be used, but multi-component data are especially useful in improving the resolution of seismic pore pressure determinations. Seismic velocity data are coupled with an estimate of the overburden pressure (usually from gravity data or borehole logs) and further processed to produce pressure estimates. This step may introduce error because subjective correction factors may be needed. Pore pressure estimation, in a well-known basin, tends to work best in basins filled with shales and sands where significant investigations have already occurred and local correction factors have already been developed (see Sayers et al., 2005; Young and Lepley, 2005; and Sayers et al., 2000). Under optimal conditions, pore pressure analysis can resolve pressure data for strata 30 to 60 m thick at medium depth in clastic basins with relatively simple stratigraphy (Huffman, 2002).

5.3.2 Electric Geophysical Methods

General Information

Electromagnetic and electric geophysical methods measure changes in the resistivity of the formation due to changes in the electrical conductivity and saturation of formation fluids. Electric methods transmit current into the subsurface, while electromagnetic methods measure the induction effect (generation of current and electric fields) in the subsurface caused by another electromagnetic field or electric current. Because carbon dioxide is relatively less conductive to electric current and brines are highly conductive, displacement of brine by carbon dioxide will result in a change in the resistivity of the formation to current flow.

One advantage of electric techniques is that they are not dependent on rock strength or formation depth but are influenced almost solely by fluid composition and saturation, which may depend on rock type and porosity, making them good candidates for tracking the progress of carbon dioxide plumes in a wide range of environments (Wynn, 2003). Electrical conductivity is also more directly influenced by carbon dioxide saturation and other changes in reservoir fluid properties than seismic variables, which are more influenced by changes in density (Wilt et al., 1995). Additionally, hardware will likely be permanently installed so that georeferencing of equipment is not an issue for subsequent tests. This advantage makes four-dimensional comparisons easier than with other methods. Resistivity methods are not recommended for dry gas reservoirs (Benson and Myer, 2002).

Time-lapse surveys can be complicated by changes in soil saturation, fluid pH, and temperature. Also, most electrical/electromagnetic deployments are better for measuring bulk changes in resistivity than for identifying thin fingers or small regions of anomalously resistive material, similar to what may occur along leakage paths. Potential imaging planes for borehole methods are also limited to planes between wells or other subsurface protrusions. Electric geophysical methods for plume and pressure tracking are characterized as potential monitoring technologies in the USDOE NETL evaluation system (USDOE NETL, 2009a). Therefore, their feasibility for plume and pressure-front tracking should be considered based on site-specific conditions and be discussed and technically justified in the Testing and Monitoring Plan.

<u>Application</u>

Although many different methods are available, two electric methods are common and likely to be useful for monitoring at GS projects: long electrodes and electrical resistance tomography (ERT). These methods are described more fully in the appendix to the *UIC Program Class VI Well Site Characterization Guidance*. There are additional emerging methods that are not described in this guidance, such as the joint use of crosswell seismic and electromagnetic technology for monitoring of the plume (Hoversten et al., 2002).

The **long electrode** method shows promise for GS; owners or operators may wish to consider this method as its utility becomes better established. The method consists of a controlled-source electric method that uses electrodes inserted into the subsurface to emit and receive electric pulses. Long electrodes are a conducting material that is in contact with both the region of interest and the surface. Specially deployed metal probes can be installed or, in some cases, the well casings themselves can be used as long electrodes. Even when wells are used, additional probes may be needed to improve resolution (Newmark et al., 2002). If metal probes are used, they will represent penetrations into the confining zone, because the probe needs to be in contact with pore fluids in the region of interest (i.e., the injection zone). Such probes, however, are generally permanently deployed, so the risk of leakage may be minimal as long as the probes themselves do not degrade.

During the survey, some long electrodes are used as receivers and measure the electric signal from charging of other electrodes with an electric current. The resistivity of the formation is calculated from the difference between the strength of the emitted and received signal and contoured on a surface map. A variety of source/receiver combinations is usually used to maximize the amount of data gathered and the number of different views of the targeted area (Daily and Ramirez, 2000). Both vertical and horizontal wells can be used as long electrodes. If only vertical wells are used, the resulting survey will have no vertical resolution. Additionally, when using long electrodes, the signal is the average over the entire length of the electrode. Therefore, small changes that only contact a small part of the electrode may be difficult to detect.

Crosswell ERT surveys have a similar deployment to crosswell seismic surveys and image a plane between the two wells. Point electrodes are deployed at set distances along a non-conductive well casing such as plastic or fiberglass (Newmark et al., 1999). Deployment can be either temporary or permanent, in which the electrodes are part of the casing. As an electric source is raised in one well, the resistivity of the formation between the wells is recorded. Ideally, the distance between wells is not more than a few hundred meters (Christensen et al., 2005), although successful ERT studies have occurred with wells spaced up to 850 m apart (Marsala et al., 2008). Because resistivity measurements are taken at different depths, this type of survey can determine both the horizontal and vertical extent of electric anomalies. This deployment produces results with greater detail than other electrical methods. However, it may require specialized hardware (e.g., specialized casing and the cabling connecting the electrodes to the surface) and dedicated monitoring wells and/or stoppages in production/injection.

Interpretation

Resistivity measurements are highly sensitive to the brine saturation within a reservoir. Measured resistivity values will increase when gas or supercritical fluid enters the pore space in the monitored location. In reservoirs without the presence of other gases, increased resistivity measurements are interpreted as the arrival of the separate-phase carbon dioxide plume (e.g., Schilling et al., 2009). Resistivity changes on the order of 30 percent can generally be detected, although under optimal conditions resistivity changes as little as 10 percent can be measured. The resolution of the survey is highly dependent upon the arrangement of the electrodes. When low electromagnetic frequencies are used, resolution is fairly low and the measurements are strongly affected by the conductivities of structures near the source and receiver (Wynn, 2003). Resolution is low for most methods when compared to seismic methods, although some methods may provide higher resolution for small areas.

Depending upon the exact deployment, electrical methods require various amounts of post-collection processing. Raw data are corrected for the effect of steel casings and obvious outliers are excluded. The data are then inverted and color-coded to produce either two- or three-dimensional resistivity maps (Schuett et al., 2008). Depending upon the method, results can be presented either as surface maps or depth sections. Like seismic methods, the results of electrical methods are interpreted visually. Electrical changes in the subsurface are also caused by changes in soil saturation, the pH of the fluids, and temperature. Such changes can complicate time-lapse surveys. In addition, several non-unique reconstructions of electrical survey data are possible, complicating data interpretation. Interpretation can be improved by considering other types of data (e.g., monitoring well data, other geophysical surveys). Furthermore, instrument calibration in a laboratory using in situ conditions can improve data quality and interpretability (e.g., Schilling et al., 2009).

5.3.3 Gravity Methods

General Information

Gravity-based methods use a gravimeter to detect the force due to gravity at a given point. Measurements may be used to track the carbon dioxide plume because carbon dioxide has a different density than the formation fluids it displaces and will have a different gravity signal strength. The contact between carbon dioxide and formation fluids might be determined both laterally with surface measurements and vertically with borehole measurements (Alshakhs et al., 2008). Gravity methods cannot be used to measure the pressure front, and they are considered to be potential monitoring technologies according to the USDOE NETL (2009a) evaluation system. Further discussion of geophysical gravity methods can be found in the *UIC Program Class VI Well Site Characterization Guidance*.

Gravity measurements for plume tracking will work best in horizontal, thick formations with high porosity and permeability where brine is being replaced by carbon dioxide and a thick enough plume is produced to create large density contrasts with stronger signals between original and post-injection conditions. Gravity monitoring may be especially useful for monitoring upward movement of gaseous carbon dioxide plumes, which can occur at relatively shallow depths (i.e., less than approximately 800 m).

Carbon dioxide is difficult to detect with gravity measurements when it occurs in thin layers. Therefore, gravity methods are likely to work better in thick saline formations than in hydrocarbon reservoirs, which are often thinner (Hoversten and Gasperikova, 2003). Depleted gas reservoirs pose a challenge for gravity monitoring because residual gas trapped within pores in the reservoir can decrease the density contrast with injected carbon dioxide (Sherlock et al., 2005). One advantage of gravity methods, particularly compared with seismic methods, is that the data are collected from a robust signal and transformed with simple equations that introduce a minimum of interpretive error. However, like electromagnetic data, the measurements are not unique to certain lithologies or features, and complementary data are helpful in interpreting the results.

Time-lapse gravity surveys should show a decrease in gravity values as carbon dioxide migrates into a location (USDOE NETL, 2009a). The method can detect mass changes and, possibly, surface deformations induced by the injection activity. The detection threshold is site specific, and it depends on reservoir depth and physical properties and the distance between the target location and the survey. A common problem in interpretation of gravity surveys is the need to account for other sources of gravity variations and instrument drift.

Application

Data are collected using a gravimeter, which measures the elongation of a wire suspending or attached to a mass. As gravity increases, the mass is pulled downward and the wire lengthens. The deformation is measured and transformed into a gravity reading. Relative gravimeters compare the gravity measurement at one point to measurements at another point. They should be calibrated at a location where the gravity is known accurately and subsequently transported to another location where the gravity is to be measured. The gravimeters then measure the ratio of the gravity at the two points; the deformation is measured and transformed into a gravity reading. Absolute gravimeters, which measure gravity by dropping a mass a short distance (several centimeters) and using a laser to measure the acceleration, are also available. Absolute gravimeters are thought to produce higher quality data than other types of gravimeters (Cooper, 2009).

Land-based and aerial gravity methods are both used to collect gravity surveys on a large scale. Land-based surveys will generally have a higher resolution than aerial data, and aerial data may not be sufficiently resolved for plume detection. For surface deployments, measurements are typically taken at discrete stations across the area of interest.

Borehole gravity surveys are similar to borehole seismic surveys. A gravimeter is lowered down the borehole and measurements are taken as the device is raised. Borehole surveys have been conducted in wells 2,000 m deep and inclined up to 60 degrees (Seigel et al., 2009). Gravity gradiometry, a slightly different data collection technique, needs to be used in regions with non-horizontal strata. Borehole gravity data can be used to monitor the carbon dioxide plume by detecting the interface between formation fluids, even if well bores do not intersect it. The gas/brine interface can be detected for hundreds of meters. With a permanently installed gravimeter, the detection distance for these interfaces could be detected at over 1 km away (Alshakhs et al., 2008). However, when using a single well it is only possible to know the radial distance of a feature from the well, not the direction.

Interpretation

After collection, gravity data are corrected for instrument drift, elevation differences, and other site-specific conditions of the deployment. For monitoring purposes, gravity data will most likely be contoured and displayed on a surface map. Like other geophysical monitoring techniques, data are usually interpreted and cross-referenced with cross-sections, stratigraphy, and regional geologic information to help constrain the most logical interpretation of the data.

5.3.4 Reporting and Evaluation of Geophysical Survey Results

The Class VI Rule requires that the owner or operator submit the results of any indirect geophysical monitoring in the semi-annual reports, pursuant to 40 CFR 146.91(a)(7). Data will be submitted in an electronic form directly to EPA, where they can then be accessed both by the UIC Program Director and other EPA offices. EPA recommends that the following information be submitted with all reports:

- A description and technical justification of all survey techniques and methodologies used.
- A map showing the location of all survey equipment positions during the test.
- A description of the use of survey markers and/or measurement stations in the geophysical surveys.
- The date and time of collection of all geophysical data.
- A description of near-surface conditions, such as soil water-saturation conditions.

- If required by the UIC Program Director, raw data collected by the survey equipment.
- A description of all data processing steps taken and the major assumptions used during data processing that may affect the interpretation of the data, if different than specified in the Testing and Monitoring Plan.
- An interpretation of all geophysical survey results relating to the position of the plume and/or pressure front and fluid leakage (if detected), including available information on injection (e.g., rate, pressure), method sensitivity, and any anomalies that require follow-up.
- Maps showing the interpreted location of separate-phase carbon dioxide in the injection zone and its location in any additional zones in which it was detected.
- A comparison of the measured position of the carbon dioxide plume with modeled predictions corresponding to the time of the survey.
- Identification and explanation of data gaps, if any.
- Any identified necessary changes to the project Testing and Monitoring Plan to ensure continued protection of USDWs.
- Presentation, synthesis, and interpretation of the entire historical data set.

The UIC Program Director will evaluate the submitted data to independently assess if the position of the carbon dioxide plume and/or pressure front are consistent with predictive modeling and to confirm USDW protection within the AoR.

5.4 Use of Geochemical Ground Water Monitoring in Plume Tracking

Ground water geochemical monitoring from wells perforated within the injection zone may be used to infer the presence or absence of carbon dioxide at a location, and therefore they may be used to augment the required activities at 40 CFR 146.90(g) for tracking the extent of the carbon dioxide plume. The Class VI Rule does not require the use of monitoring wells for the purposes of tracking the extent of the carbon dioxide plume in all cases. In certain cases, the owner or operator, collaboratively with the UIC Program Director, may determine that the use of geochemical ground water monitoring may be necessary to track the carbon dioxide plume sufficiently. The decision whether to use geochemical ground water monitoring for plume tracking will be based on site-specific conditions and predicted system behavior (e.g., rate and direction of migration of the separate-phase plume and/or pressure front). The owner or operator is encouraged to consult the UIC Program Director while making this decision during development of the Testing and Monitoring Plan.

EPA recommends that the Testing and Monitoring Plan include a detailed description of the number and placement of monitoring wells and the site-specific factors that have been considered, as well as a description of why geochemical monitoring is needed. Similarly, a discussion of the parameters to be monitored and the frequency at which sampling and analysis will be performed should be included in the plan. It is important that the owner or operator describe method sensitivity and how the monitoring plan will detect plume extent and/or any endangerment to a USDW. If phased or triggered monitoring is proposed, all factors considered for the development of the strategy should also be included in the plan. More information on the development of the Testing and Monitoring Plan can be found in the *UIC Program Class VI Well Project Plan Development Guidance* and Section 1.2 of this guidance document.

Evaluation of Plume Tracking Using Ground Water Geochemical Monitoring

EPA recommends that the following be considered in determining whether to use ground water geochemical monitoring as a component of plume tracking:

- In cases when the UIC Program Director has determined that geophysical techniques are not appropriate for a given site for plume tracking, direct methods must be used [40 CFR 146.90(g)], and EPA recommends the use of geochemical ground water monitoring for plume tracking. Section 5.3 discusses the types of geologic formations for which indirect geophysical methods may not be suitable. For example:
    - Seismic imaging may not be appropriate in salts, basalts, coal seams, carbonates, non-sedimentary units, depleted gas reservoirs, and shallow natural gas reservoirs. Seismic methods can also be affected by anthropogenic noise and are hard to deploy in populated areas.
    - Time-lapse electrical/electromagnetic methods can be complicated by changes in soil saturation, fluid pH, and temperature, and they are not favorable for imaging thin fingers of carbon dioxide fluid that may occur along preferential pathways.
    - Carbon dioxide is difficult to detect with gravity measurements when it occurs in thin layers. Therefore, gravity methods are likely to work better in thick saline formations than in hydrocarbon reservoirs, which are often thinner. Depleted gas reservoirs also pose a challenge for gravity monitoring because residual gas trapped within pores in the reservoir can decrease the density contrast with injected carbon dioxide.
- Geophysical techniques are capable of imaging the separate-phase carbon dioxide plume, but not the larger dissolved-phase carbon dioxide plume that is created by dissolution of carbon dioxide into native fluids. In cases where there may be risks associated with the dissolved-phase plume, geochemical ground water monitoring is encouraged.
- If geophysical methods will be deployed, but are prone to a significant amount of uncertainty, ground water geochemical monitoring may be used to complement geophysical surveys (e.g., the site-specific factors discussed above). For example, geochemical data may be used to reduce uncertainty with interpretation of geophysical results during data processing.
- In some cases, it may be appropriate to conduct relatively frequent ground water geochemical monitoring for plume tracking (e.g., every six months), with less frequent

repeat geophysical surveys to complement the geochemical monitoring (e.g., every five years). A complementary program of geochemical monitoring and geophysical surveys may be designed to provide sufficient tracking of the carbon dioxide plume.

Application

Considerations related to collection and analysis of ground water samples within the injection zone will be similar to those for wells perforated above the confining zone, described in more detail in Section 4 of this guidance document. EPA recommends similar sampling protocols, QA/QC, and analytical procedures as those discussed for ground water geochemical monitoring above the confining zone. For the purposes of plume tracking, EPA recommends that fluids collected from the injection zone be monitored for carbon dioxide, at a minimum. If available, downhole probes may be used to estimate carbon dioxide concentrations in lieu of sample collection and laboratory analysis. Additionally, an analysis of headspace gas (gas that accumulates at the top of the well) at monitoring wells may be used as an indicator of the proximity of the plume.

Wells constructed to directly monitor pressure within the injection zone may also be used for geochemical monitoring. In rare cases, particularly when indirect geophysical techniques are not used, additional monitoring wells may be necessary within the injection zone to track the carbon dioxide plume. Specifically, EPA recommends the following considerations for design of the monitoring well network for plume tracking:

- EPA recommends that monitoring wells sited near injection wells be perforated at a similar interval to the injection well(s). For those wells sited further from injection wells, the owner or operator may consider perforating wells at shallower depths (closer to the injection zone/confining zone interface) to account for vertical buoyant flow as carbon dioxide migrates laterally.

- For projects predicted to have a separate-phase plume and/or pressure front that moves preferentially in one direction, EPA recommends that monitoring efforts be concentrated in that direction.

- Well placement should be based on the predicted rate and direction of migration of the separate-phase plume and/or pressure front.

- The number of monitoring wells placed within the injection zone should be determined such that the migration of the carbon dioxide plume may be tracked sufficiently. The determination of the number of injection zone wells may be based on a modeling and/or statistical analysis, as well as the overall testing and monitoring strategy to detect any deviation from the modeled predictions or planned operation. EPA recommends that this determination be documented in the Testing and Monitoring Plan.

Interpretation

The objective of ground water monitoring within the injection zone is to track the extent of the carbon dioxide plume by determining the presence or absence of carbon dioxide at a location.

Determination of plume thickness and its three-dimensional extent may require additional assessments. EPA recommends that the owner or operator evaluate the collected data in comparison to baseline data and other previously collected data. Trends that are indicative of the presence of the carbon dioxide plume at a particular location may include an increase in the concentration of dissolved carbon dioxide at in situ conditions. The concentration of carbon dioxide at specific in situ conditions (e.g., temperature, pressure) may be used to ascertain if separate-phase carbon dioxide may be present, based on accepted mass-transfer relations and equilibrium constants. Results that may be indicative of the presence of the separate-phase plume at the monitoring location also include reduced sample fluid density and the presence of separate-phase carbon dioxide in the sampled fluid, as measured at in situ conditions.

EPA recommends that, where possible, data collected from monitoring wells within the injection zone be compared to indirect geophysical data regarding the extent of the separate-phase plume. Comparison and interpretation of the two data sets may be used to elucidate uncertainties related to either monitoring technology.

6 Surface Air and Soil Gas Monitoring

At the discretion of the UIC Program Director, the owner or operator may be required to monitor surface air and/or soil gas for carbon dioxide leakage that may endanger USDWs [40 CFR 146.90(h)]. Under the Class VI Rule, all surface air and/or soil gas monitoring required for compliance with UIC regulations must be based on potential risks to USDWs [40 CFR 146.90(h)(1)]. The objective of surface air and/or soil gas monitoring under the Class VI Program is to provide an additional line of evidence of whether carbon dioxide has leaked from the injection zone and potentially endangered USDWs.

If the UIC Program Director requires surface air and/or soil gas monitoring pursuant to requirements at 40 CFR 146.90(h), and an owner or operator demonstrates that monitoring employed under Subpart RR of the Greenhouse Gas Mandatory Reporting Rule [40 CFR 98.440 to 98.449] accomplishes the goals of 40 CFR 146.90(h)(1) and (2) and meets the requirements at 40 CFR 146.91(c)(5), the UIC Program Director must approve the use of monitoring employed under Subpart RR [40 CFR 146.90(h)(3)]. Subpart RR, promulgated under the authority of the Clean Air Act, complements UIC requirements with the added monitoring objectives of verifying the amount of carbon dioxide sequestered, as well as collecting data on any carbon dioxide surface emissions. Section 4 of the Subpart RR General TSD (USEPA, 2010) describes a suite of monitoring technologies available for surface air and soil gas monitoring. Section 5 of the TSD provides considerations for reporters in developing their Monitoring, Verification, and Reporting (MRV) plans for Subpart RR.

EPA recommends that when surface air and/or soil gas monitoring is conducted in compliance with multiple regulatory programs, the owner or operator design a monitoring strategy that efficiently meets all monitoring objectives. In some cases, separate technologies (e.g., eddy covariance towers versus soil gas probes) may be used to meet specific monitoring objectives. However, it is likely that data collected from multiple techniques will be complementary and useful in data analysis and interpretations for all applicable regulatory programs.

Carbon dioxide detection above background levels in soil gas or at the surface does not necessarily demonstrate that USDWs have been endangered, but it may indicate that a leakage pathway or conduit exists at some point in the operation. For example, the carbon dioxide delivery system or ancillary wellhead equipment may be a leakage source. Carbon dioxide migration into the unsaturated zone or surface air from the injection zone may occur from a non-point or point source or a combination of both. Non-point sources include migration of injectate through the confining zone and overlying zones through a diffuse network of high-permeability pathways, including micro-fractures. Point sources include leakage through artificial penetrations (wells), individual fractures, fault zones, and surface equipment. In either case, leaking carbon dioxide at these depths will be in the gaseous phase, and it will mix with resident gases (e.g., air, soil gas). Carbon dioxide migration may be detected by observation of concentrations elevated above background levels. Detection of migration is more likely for point sources, because the resulting carbon dioxide concentrations will likely be greater. Common to surface air and soil gas monitoring is the need to account for natural background carbon dioxide concentrations, which fluctuate seasonally. In addition to monitoring for carbon dioxide concentration, surface air and/or soil gas may also be monitored for tracer gases or carbon dioxide isotopic signatures, which may aid in evaluating carbon dioxide sources. A detailed discussion of monitoring for tracer gases and carbon dioxide isotopes is included in the Subpart RR General TSD (USEPA, 2010). There are also some emerging methods, such as the process-based method for near-surface leakage detection used at the Weyburn-Midale enhanced oil recovery (EOR) project site (see the Appendix for more information). This method relies on gas concentration relationships to identify the dominant near-surface processes (Romanak et al., 2012).

The Class VI Rule, at 40 CFR 146.90(h)(2), requires that monitoring frequency and spatial distribution of surface air and/or soil gas monitoring be determined using baseline data, and the Testing and Monitoring Plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under 40 CFR 144.12. Information regarding determination of baseline is given in the *UIC Program Class VI Well Site Characterization Guidance.* In addition, EPA recommends that the location of surface air and/or soil gas sampling points be based on the following considerations:

- Avoiding areas of highly fluctuating background concentrations, based on previously recorded data.
- Sampling near obvious point sources, including wellheads, artificial penetrations, natural discharge points, and fault or fracture zones. A transect-profiling approach may be used for linear features, such as faults (see ASTM, 2006b).
- If intended to monitor for non-point source leakage, monitoring throughout the AoR, using a grid methodology in areas of potential leakage. Grid cell spacing may range over several orders of magnitude, depending on site specific factors. See ASTM (2006b) for discussion of establishing a soil sampling grid.

6.1 Soil Gas Monitoring

<u>General Information</u>

Soil gas monitoring at a GS project refers to sampling of vapors within the unsaturated zone (i.e., the zone from the ground surface to the capillary fringe above the water table), or across the ground surface, and analysis for the vapor-phase concentration of carbon dioxide. Soil gas monitoring is a relatively common technology, used in characterization of contaminated sites and for exploration of natural resources, including petroleum, natural gas, and precious metals. Unsaturated-zone samples may be collected from soil gas probes. Soil flux chambers are used to collect vapors across the ground surface. As described below, collected gas samples may be analyzed using portable gas analyzers.

<u>Application</u>

Soil gas is traditionally sampled using whole air or sorbent methods. Whole air methods collect a sample of soil gas for vapor-phase analysis. Sorbent methods collect non-polar chemicals on a sorbent material that is put in place at the site for an extended period of time. For GS projects, EPA recommends use of whole air sampling methods because data collection and interpretation are comparatively straightforward.

Soil gas probes are borehole sampling devices that are driven into the unsaturated zone. The tip of the sampling probe contains a sampling tube that runs to the surface (Figure 6-1). During sample collection, a vacuum is applied to the sampling tube on the surface, and soil gas from the sampled depth is collected. For GS projects, EPA recommends that soil gas probes be driven to a depth as close to the potential leakage point as possible. In most cases, it is recommended that soil gas probes be driven as deep as possible while remaining above the water table capillary fringe, accounting for seasonal and long-term fluctuation. In any case, it is recommended that soil vapor samples be collected at depths great enough to be out of the zone of influence of atmospheric chemical concentration and temperature fluctuations; in addition, the probe should not be terminated in a low-permeability (e.g., clay) zone. During installation, it is recommended that the probe tip be emplaced midway within a sand pack (minimum of one foot; e.g., CalEPA, 2003). The borehole may then be grouted to the surface with hydrated bentonite or a cement/bentonite mixture.

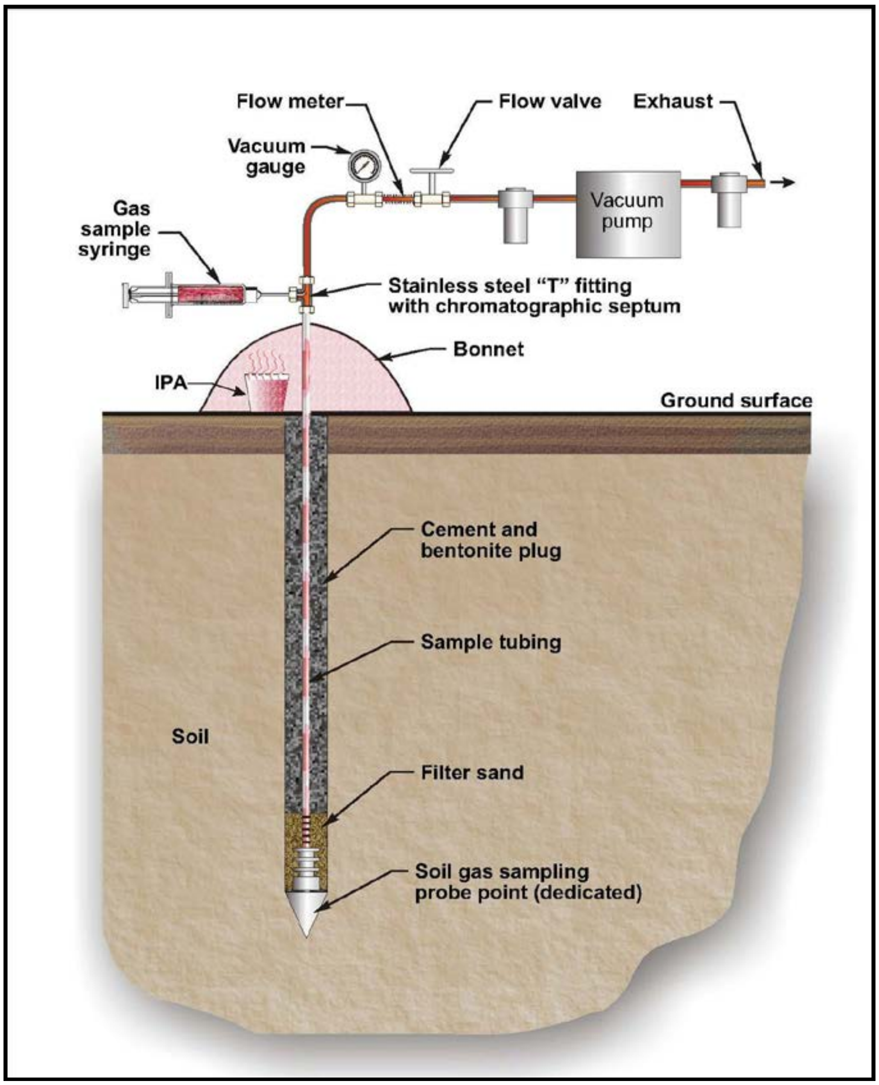

Figure 6-1. Schematic of a soil gas sampling system (adapted from Wilson et al., 1995; not to scale).

Prior to sample collection from a soil gas probe, the probe is purged, similar to ground water monitoring wells (see Section 4.3). Purge tests are conducted on each typical lithologic unit into which soil vapor probes are installed to determine the appropriate purge volume (CalEPA, 2003). In general, it is recommended that purging and sampling rates not be greater than 100 to 200 mL per minute. Leakage of surface air through the borehole during sampling, and concomitant sample dilution, is of potential concern during sample collection. During sampling, a leakage test may be conducted by placing a tracer compound, such as isopropyl alcohol, at the surface. A leakage test sample would then be analyzed using appropriate analytical methods for detection of the tracer. Samples may be collected in reusable containers, such as glass syringes, as long as appropriate decontamination procedures are adhered to between sample collections. Samples may be analyzed in the field for carbon dioxide using a standard handheld gas analyzer, such as a portable infrared detector. The portable analyzer should be calibrated regularly to a gas standard according to manufacturer specifications.

Soil flux chambers, also referred to as accumulation chambers, are installed at the ground surface and are used to measure the flow and composition of gases at the soil surface (Figure 6-2). The chamber is swept by injection of a carrier gas, and the resulting mixture is collected for analysis (ASTM, 2006b). The flux of carbon dioxide out of the soil surface into surface air may be calculated if flow rates of the injected gas are known. Compared to soil gas probes, soil flux chambers are more limited in their ability to detect carbon dioxide leakage. Samples are diluted by use of the carrier gas, decreasing method sensitivity. Vapor flux from deeper zones near the USDW to the soil surface may be reduced due to soil characteristics such as high water saturation and the presence of low permeability lenses. However, the use of soil flux chambers may be preferred because borehole installation is not necessary, and equipment may be reused at several sites. The use of soil flux chambers may also be complementary to soil gas probes; whereas probes identify a zone of leakage, chambers may be used to estimate the flow and composition at the surface. Additional information regarding soil flux chambers that pertains to quantification of leakage rates is available in the Subpart RR General TSD (USEPA, 2010).

Interpretation

Subsurface gases are relatively less affected by surface environmental forces (e.g., atmospheric dispersion) and associated dilution. Therefore, monitoring soil gas concentrations of carbon dioxide may be preferable over surface air monitoring for early detection of leakage. It is recommended that carbon dioxide concentrations observed in soil gas measurements be compared to background levels to identify potential anomalies that may be indicative of leakage of carbon dioxide from the intended storage formations and possible USDW contamination.

Background soil carbon dioxide fluxes, concentrations, and isotopic compositions show large variations and are dependent on exchange with the atmosphere, organic matter decay, uptake by plants, root respiration, deep degassing, release from ground water due to depressurization, and microbial activities (Oldenburg and Lewicki, 2004). Therefore, EPA recommends that baseline studies be carried out prior to injection of carbon dioxide to characterize the background spatial trends and variability.

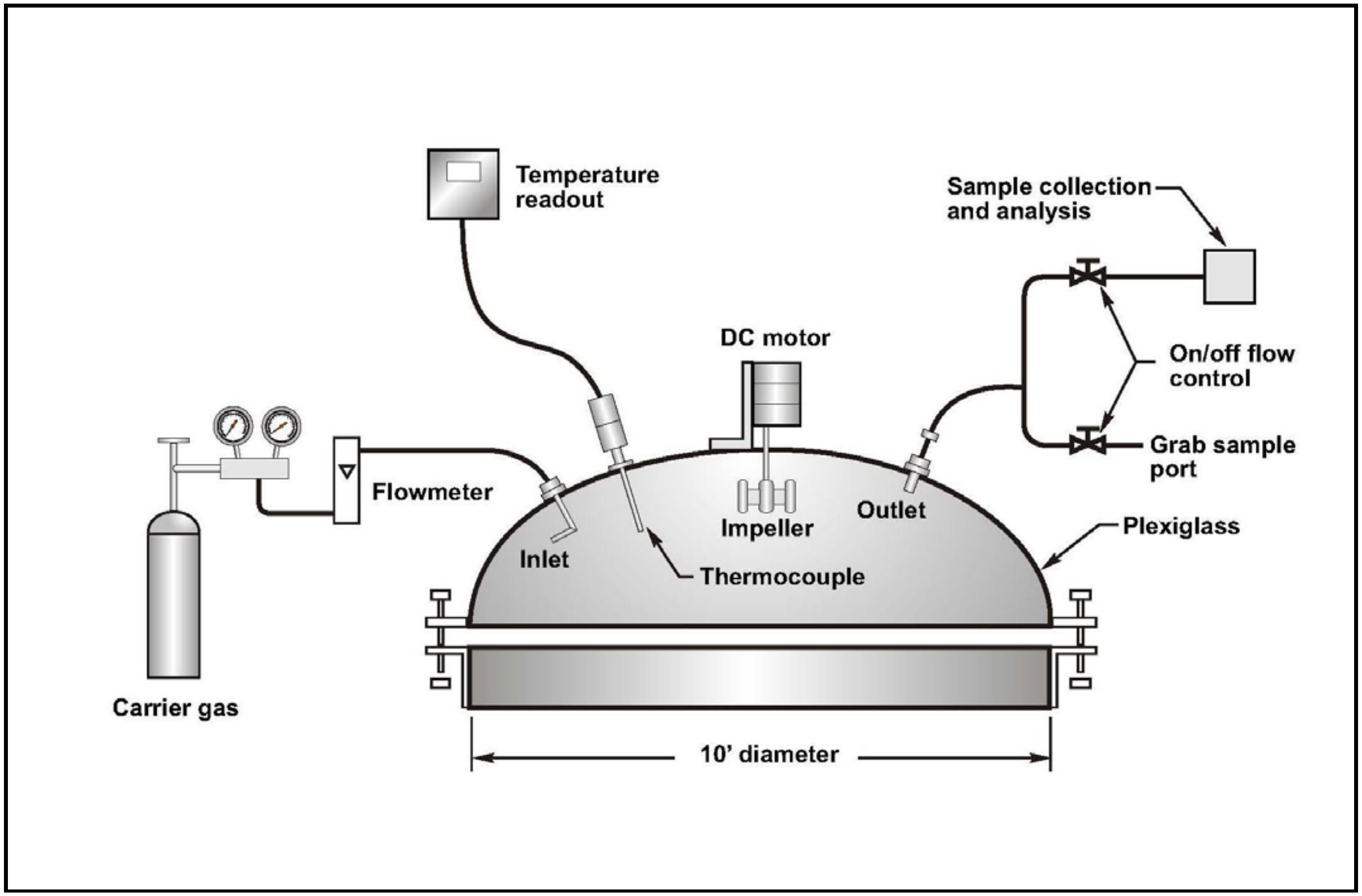

Figure 6-2. Schematic of a soil flux chamber (adapted from ASTM, 2006b; not to scale).

Such studies would include repetitive measurements over time taken at several fixed representative sites to capture diurnal to seasonal variations (Oldenburg et al., 2003). EPA particularly recommends that such monitoring include areas with geologic and artificial structures (e.g., faults, artificial penetrations) that may potentially create conduits for migration to occur. During these measurements, soil temperature and moisture are recommended to be monitored along with the collection of records of atmospheric temperature, pressure, and wind speed and direction measured at a weather station. Modeling of soil fluxes may be used to support a determination of background levels. Ideally, robust (e.g., multi-year) pre-injection background carbon dioxide data will be available from the locations monitored during the life of the GS project. Importantly, collected gas composition data using different methods (e.g., different types of soil gas probes, different depths) are not directly comparable. If pre-injection data are not available, local soil gas data collected outside of the region of influence of the project may be used for comparison. Identification and quantification of leakage is also an integral part of the Subpart RR requirements and more information can be found in the Subpart RR General TSD (USEPA, 2010). See also the *UIC Program Class VI Well Site Characterization Guidance* for additional information on collecting baseline data.

It is recommended that seasonal fluctuations in background levels be considered during this comparison. If a sampling grid has been established, data collected during a sampling event may be plotted on a site map and contoured. Sampling locations with the greatest carbon dioxide concentrations may be in the vicinity of a migration pathway. However, migration pathways may be circuitous within the subsurface, in which case it may not be straightforward to determine the migration source strictly from soil gas data. Furthermore, non-point sources may result in large carbon dioxide plumes in soil gas without a discernible central location. If soil gas data indicate potential migration, USDWs in the vicinity may be monitored for any geochemical changes and impairment.

Multi-level soil vapor data collection points are typically necessary to provide the basis for making three-dimensional interpretations (i.e., lateral and vertical extent) of carbon dioxide concentrations in soil gas. Like other monitoring techniques, data are usually interpreted and cross-referenced with cross-sections, stratigraphy, and regional geologic information to help constrain the most logical interpretation of the data.

<u>Reporting and Evaluation</u>

If soil gas monitoring is required by the UIC Program Director, results must be submitted in the semi-annual reports [40 CFR 146.91(a)(7)]. Additionally, any release of carbon dioxide to the atmosphere or biosphere detected through soil gas monitoring must be reported within 24 hours, pursuant to the Class VI Rule requirements at 40 CFR 146.91(c)(5). EPA recommends that submittals in the semi-annual reports include the following:

- Records, schematics, and technical justification for all soil gas probe or soil flux chamber equipment installation.
- Date and time of measurements.

- Description of existing areas of geologic and artificial structures that are potential conduits for carbon dioxide migration.

- A database of all available soil gas data from each sampling location and depth, including any background data and QA/QC samples.

- Soil and air temperatures and pressure, if required.

- Interpretive maps and/or graphs of carbon dioxide trends.

- Records of the calibration of any analytical equipment, including handheld portable gas analyzers.

- Records of all field activities, including vacuum-volume purge tests, sample probe purging and sampling rates.

6.2 Surface Air Monitoring

General Information

Surface air above the GS project may be analyzed for elevated levels of carbon dioxide. Collection and analysis of surface air samples is relatively straightforward. Similar to soil gas sampling, EPA recommends that collected data be compared to background levels in order to assess leakage [40 CFR 146.90(h)(2)]. Surface air monitoring is complicated by other carbon dioxide sources, including soil and vegetation, industrial processes, and surface carbon dioxide delivery and processing equipment. Additionally, the atmosphere is well mixed, and the leakage signals may be diluted such that they cannot be detected (USDOE NETL, 2009a). As with soil flux chambers, carbon dioxide leaking through USDWs may not emanate at appreciable rates to the surface due to retardation in the unsaturated zone. For these reasons, surface air monitoring will likely only be useful for detecting large point-source leaks. Surface air monitoring, however, may be required by other state or federal regulations, including Subpart RR. The Subpart RR General TSD (USEPA, 2010) discusses surface air monitoring techniques as they pertain to quantification of leakage from a GS project.

Application

The simplest application of surface air monitoring is the use of portable or stationary **carbon dioxide detectors**. Infrared detectors, also used for soil gas sampling (Section 6.1), may be used for field-analysis of surface air. Stationary monitors may be used to continuously collect and record ambient carbon dioxide concentrations. Handheld portable analyzers may be used to spot check carbon dioxide concentrations at given times. Alternatively, sampling devices may be left at the surface to collect air samples over a given time, such as a 24-hour interval (e.g., Summa canisters).

Advanced leak detection systems, often used along pipelines, consist of a portable gas analyzer mounted to a global positioning system (GPS)-referenced ground or airborne vehicle. The Subpart RR General TSD (USEPA, 2010) further discusses carbon dioxide detectors, including detection of tracers and carbon dioxide measurements.

Eddy covariance towers may be used to monitor carbon dioxide concentrations at a height above the ground surface. These towers use an infrared gas analyzer to continuously monitor carbon dioxide concentrations. They also use additional equipment to measure wind velocity, relative humidity, and temperature. Primarily, these towers would be used to detect carbon dioxide flux of large areas in real time (USDOE NETL, 2009a). Interpretation of atmospheric data from eddy covariance towers requires significant data processing and may be complicated by local weather patterns and precipitation.

Interpretation

EPA recommends that measured carbon dioxide concentrations in surface air be compared to locally collected background data. The average carbon dioxide concentration in surface air is currently 0.038 percent (NOAA, 2011), though local background concentrations do vary. Carbon dioxide levels that are significantly higher than background levels may be indicative of leakage. However, for reasons discussed above, surface air data is not ideal for detecting the source or location of leakage that may impact a USDW. If carbon dioxide leakage is suspected based on surface air data, additional monitoring may need to be conducted in order to elucidate the source of the leak and assess any impairment of USDWs. This may involve further sampling using soil gas probes and ground water monitoring within surficial USDWs.

Reporting and Evaluation

If surface air monitoring is required by the UIC Program Director, results must be submitted electronically in the semi-annual reports [40 CFR 146.91(a)(7)]. Additionally, any release of carbon dioxide to the atmosphere or biosphere detected through surface air monitoring must be reported within 24 hours, pursuant to the Class VI Rule requirements at 40 CFR 146.91(c)(5). EPA recommends that submittals in the semi-annual reports include the following:

- Records and technical justification of the location and time intervals of all surface air sampling.
- A database of all available surface air data from each sampling location, including any background data and QA/QC samples.
- Interpretive maps and/or graphs of carbon dioxide trends.
- Records of the calibration of any analytical equipment, including gas analyzers.
- Records of all field activities.

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Appendix: Testing and Monitoring Case Studies

GS is an emerging technology and, as of the writing of this document, few commercial-scale projects have begun operation. However, numerous field-scale pilot projects have been initiated in the United States and internationally. One objective of these projects has been testing and evaluation of different monitoring techniques. EPA believes that learning from early projects will be integral to developing effective testing and monitoring programs and protecting USDWs. The case studies presented here provide examples of the application of several of the technologies discussed in this guidance. The reader is referred to references cited within the case studies for further information regarding use of these techniques at the specific projects. Importantly, the majority of the projects discussed here are not mature commercial-scale projects, but rather research-oriented or pilot projects. The testing and monitoring techniques described in these case studies are provided as examples of field applications of these techniques; Testing and Monitoring Plans for individual Class VI projects will be determined based on site-specific considerations in communication with the UIC Program Director. As additional data are collected from larger-scale GS projects, EPA is committed to collecting and evaluating new data and information as a component of the Class VI Rule adaptive approach.

Case studies were selected to represent a range of project types, geographic locations, geologic settings, and monitoring techniques, as summarized in Table A-1. Other GS projects in the United States and other countries provide additional examples of GS monitoring techniques applied in commercial and research settings. For example, operators of the Salt Creek EOR project in Wyoming have used various methods to track and contain carbon dioxide leaks, and the Mountaineer project in West Virginia (though not put into commercial-scale operation) provides an example of a planned monitoring program for GS in the Mount Simon saline aquifer. Interested parties are encouraged to review the available literature on these and other projects.

Table A-1. Summary of case study projects and key testing/monitoring methods used at each project.

Project	Project Type	Key Technologies Employed
Cranfield (Mississippi)	EOR/GS	Seismic and electric geophysical methods, geochemical analysis, pressure monitoring, surface air/soil gas monitoring, tracers
Paradox/Aneth (Utah)	EOR/GS	Seismic and microseismic methods, soil gas monitoring, pressure monitoring, tracers
Ketzin (Germany)	Saline aquifer	Seismic and electric geophysical methods, pressure monitoring, geochemical analysis, soil gas monitoring, tracers
Weyburn (Canada)	EOR/GS	Seismic and microseismic methods, pressure monitoring, geochemical analysis, process-based soil gas monitoring
West Pearl Queen (New Mexico)	Depleted oil field	Seismic methods, pressure monitoring, tracers
In Salah (Algeria)	Gas production	Remote satellite imaging, seismic and microseismic methods, surface air/soil gas monitoring

I. Cranfield Oil Field

The Southeast Regional Carbon Sequestration Partnership (SECARB) is conducting a research-oriented EOR/GS pilot project at the Cranfield oil field, located approximately 20 km east of Natchez, Mississippi. Injection activities at the site target an 18 m thick sandstone layer in the Upper Cretaceous Lower Tuscaloosa Formation, at a depth of 3,300 m (Hovorka et al., 2011). The reservoir is highly heterogeneous and consists of stacked and incised channel fills. A thick marine mudstone portion of the Middle Tuscaloosa Formation is the lowest element of a regional confining system and is overlain by several additional confining beds. The uppermost confining unit consists of thick mudrocks of the Paleocene Midway Formation (Hovorka, 2011). SECARB conducted a stacked injection and monitoring test using existing wells dating from the 1960s. Injection of carbon dioxide for the USDOE NETL Phase II stacked test began in July 2008, and, as of early 2011, 2.5 million tons of carbon dioxide had been injected through 24 wells (Hovorka et al., 2011; Lu et al., 2012).

Monitoring activities at Cranfield have been conducted in several study areas, including a high volume injection test (HiVIT); a "detailed area of study" (DAS) well-based monitoring test; a geomechanical test (GMT) area near a non-transmissive fault; and a surface monitoring program at the so-called "P-site," which includes monitoring a plugged and abandoned well, a well pad, an open pit, and plants (Hovorka, 2011). The reservoir was characterized extensively prior to the start of injection, and initial site characterization has been augmented by wireline logs, core analyses of reservoir and confining intervals, hydrologic testing, and fluid sampling (Hovorka, 2011). Baseline temperature and pressure measurements were gathered in spring 2008, and monitoring began in July 2008, after the start of injection. Pressure has been monitored continuously in both the injection zone and a sandstone unit in the Upper Tuscaloosa Formation that serves as a monitoring horizon above the confining zone (SECARB, 2012).

Field-wide injection began in July 2008, with a higher injection rate obtained in the HiVIT by December 2009. Injection into the DAS occurred simultaneously. Bottomhole pressure has remained stable since the maximum injection rate at field pressure was reached in 2011 (USDOE NETL, 2012b). U-tube samplers were used for liquid and gas sampling from the perforated zone of injection wells (Lu et al., 2012). During a temporary blockage of the U-tube sampler, an alternative downhole sampler was used to collect fluid samples (Lu et al., 2012). Liquid sample analyses included measurements of: pH, electrical conductivity, alkalinity, hydrogen sulfide, major cations and anions, trace metals, carbon isotopes, benzene, toluene, ethylbenzene, xylenes, VOCs, phenols, and polyaromatic hydrocarbons. Gas samples, analyzed for carbon dioxide, methane, and carbon isotopes, were analyzed using a chromatograph equipped with FIDs and thermal-conductivity detectors. Core samples were collected and analyzed using X-ray diffraction to determine the mineral composition.

The carbon dioxide plume was tracked using a variety of seismic and electric geophysical methods. Technologies used include casing-deployed crosswell ERT, continuous active source seismic monitoring, crosswell seismic, VSP, and repeat three-dimensional surface seismic in the HiVIT (Hovorka, 2011; Daley, 2012). Surface seismometers were also installed but, due to noise levels, were not useful (Hovorka, 2011). Results from ERT indicated significant changes in conductivity, likely related to replacement of brine by carbon dioxide (Hovorka et al., 2011; USDOE NETL, 2012b). However, overall seismic monitoring varied with scale (surface versus

VSP), which is potentially related to naturally high methane levels masking the carbon dioxide (Daley et al., 2012).

Results from geochemical and geophysical monitoring indicated that the formation water was methane-saturated prior to carbon dioxide injections, and carbon dioxide-water-rock reaction appears to be minimal. The carbon isotopic ratio from gas samples suggests possible mixing between injected and original formation gas, indicating minor carbonate dissolution during injection. These results were further supported by the brine sampling, which indicated that brine chemistry was largely unaltered after the start of injection (Lu et al., 2012).

A soil gas laboratory was installed at the P-site and quarterly monitoring was initiated. The purpose of the soil-gas program was to monitor a methane anomaly (detected using a soil gas probe) at a plugged and abandoned well that had been re-entered. A risk assessment had previously concluded that older, abandoned wells at the site posed a significant leakage risk (Hovorka, 2011). Spatial gas profiling from the study indicated high levels of carbon dioxide and methane in near-surface soils; however, the study team determined that the elevated levels of carbon dioxide were likely the result of oxidation of thermogenic methane from the deep oil and gas reservoir and were not related to injection activity. Monitoring for carbon, hydrogen, and noble gas tracers, as well as induced tracers (e.g., perfluorocarbons), was also used to assess any potential carbon dioxide leakage in the near-surface (Lu, 2011).

Field tests in the HiVIT, DAS, and P-site test areas have been completed and, as of 2012, Phase III of the Cranfield project was selected by USDOE NETL to move forward (USDOE NETL, 2012a and 2012b). The GMT efforts were initiated in fall 2009, to assess sub-fracture stress near a non-transmissive fault; however, because of high temperatures and corrosion of the well bore environment, the wireline failed and the test was not successful. The Phase III work will involve refining the existing activities to determine the validity of the various technologies used, and it incorporates a proposed 10-year monitoring program. Proposed monitoring activities include soil gas sampling; monitoring shallow ground water; measuring carbon dioxide surface flux; monitoring carbon dioxide plume movement using tracers; downhole well logging; and incorporating seismic and electromagnetic techniques to detect potential leakage and monitor the plume (USDOE NETL, 2012a). Overall, monitoring, data analysis, and outreach activities at Cranfield are expected to continue through 2017 (USDOE NETL, 2012a).

II. Paradox/Aneth Project

Aneth Field is an active hydrocarbon production field in the Paradox Basin near Bluff, Utah. The Southwest Regional Partnership (SWP) operates the pilot-scale Paradox/Aneth EOR/GS project in conjunction with field operators. The targets of the carbon dioxide flood are the Desert Creek and Ismay members of the hydrocarbon-bearing Paradox Formation, a Paleozoic carbonate formation. The injection zone is located at a depth of approximately 1,930 m and has an average thickness of 17 m, although the thickness is highly variable (USDOE NETL, 2009b). The Gothic Shale and an organic-rich mud deposit (the Chimney Rock Shale) serve as upper and lower confining zones, respectively (SWP 2008; Cheng et al., 2010). The reservoir is not strongly faulted and the gross structure is depositional (USDOE NETL, 2009b). Aneth Field is typical of many Western hydrocarbon fields; the site was selected to develop factors that can be used to identify other storage sites in the western United States as well as to develop a risk assessment framework for such sites (SWP, 2008).

SWP began injection in August 2007, at a rate of approximately 15,000 tons per year of carbon dioxide (Rutledge et al., 2008a). Carbon dioxide flooding for EOR has occurred in other parts of Aneth Field since 1985, though the fate of the injected carbon dioxide was poorly understood (Chidsey et al., 2006). Baseline studies were completed prior to the beginning of carbon dioxide flooding in 2007 (SWP, 2008). Although the flood will last for five to eight years to maximize potential oil recovery, monitoring by SWP only lasted for the first two years of the commercial flood. Seismic methods were used to track the injected carbon dioxide plume. A permanent 60-level, 96-channel geophone array was installed in a monitoring well to allow for high quality, repeatable VSPs at low cost (Huang et al., 2008). From 2007 to 2009, one baseline and two repeat VSP surveys were completed. Between the baseline and first repeat survey, approximately 10,500 tons of carbon dioxide had been injected (Rutledge et al., 2008a). For each survey, data were obtained from one zero-offset and seven offset source locations. Double difference seismic tomography, which has greater resolution capabilities, was also applied (Zhou et al., 2010; Slaker, 2011). Results from the geophones indicated that time-lapse VSPs coupled with high resolution migration and scattering analysis can provide reliable imaging of carbon dioxide migration within the target formation (Huang et al., 2008).

Microseismic monitoring has also been used continuously since injection began in 2007 (Huang et al., 2008; SWP, 2008). The 60-level geophone string used in the VSP surveys was repurposed for microseismic monitoring. Following injection, the number of microseismic events increased, and episodic events (magnitude -1 to 0) were detected within 22 kilometers of the geophone string at an occurrence rate of approximately zero to 10 events per day starting in March 2008. According to poroelastic stress models, the likely cause for the increase in seismicity was an increase in fluid pressure within the target formation. The locations of the microseismic activity indicate northwest/southeast fractures within the reservoir (Rutledge et al., 2008b; Plasynski et al., 2011). In addition to the carbon dioxide plume, subsurface pressure, including annulus and aquifer pressure, was also tracked at the site (SWP, 2008).

A tracer study using 1,3,5-naphthalene trisulfonate and 2,6-naphthalene disulfonate was conducted at Aneth to better characterize flow patterns during waterflooding. During subsequent carbon dioxide flooding, perfluorocarbons and propanol were also used as tracers to characterize carbon dioxide flow. Results indicated that these tracers were effective and that various combinations of these tracers could be used in GS applications in similar settings (Rutledge, 2010).

Soil carbon dioxide flux measurements were used to monitor for potential carbon dioxide leakage. Instruments included an automated soil carbon dioxide flux system, a survey chamber, and soil temperature probes. These methods were useful in determining natural background and seasonal variation in carbon dioxide flux. Monitoring prior to and during carbon dioxide injection did not identify any leaks (Rutledge, 2010).

For over two years, continuous self-potential measurements were applied as a supplemental technique to measure pressure changes around the wellhead related to carbon dioxide injection. The method involves using a non-polarizing electrode to measure naturally occurring voltages formed by fluid flow. The project involved installing 16 silver/silver chloride non-polarizing electrodes at eight locations of differing distances from the wellhead. Anomalies were observed at several injection wells, which were initially attributed to a geobattery mechanism (the production of an electrical source current in an electrically conducive ground). While the method detected anomalies around some production wells, for others the method was not useful and produced poor quality data due to noise levels (Rutledge, 2010).

Field hydrothermal experiments were conducted at Aneth to understand mobilization of trace metals related to carbon dioxide injection at the caprock-reservoir boundary. Preliminary results from the study, which involved collecting reservoir brine samples, indicate that the pH decreased following carbon dioxide injection, and mobilization of iron, lead, barium, zinc, and copper led to elevated levels of these metals in reservoir fluids. Further data analysis is planned, as well as additional experiments to evaluate barium, arsenic, and iron mobilization (Marcon et al., 2012).

III. Ketzin/CO_2SINK Project

The Ketzin project, a pilot-scale project located in the German state of Brandenburg, is the first onshore European GS project. Injection activities at the site target a 650 m deep, 80 m thick sandstone saline aquifer in the Triassic Stuttgart Formation (Schilling et al., 2009; MIT, 2010). The first phase of the project, called CO_2SINK (for "CO_2 Storage by Injection into a Natural Saline Aquifer at Ketzin"), ran from 2004 to 2010 and was supported by the European Union. Since the end of the CO_2SINK project in 2010, ongoing monitoring efforts at the site have been supported by the German Federal Ministry for Education and Research. Carbon dioxide injection began in June 2008, and, as of December 2011, approximately 57,000 tons of carbon dioxide had been injected. The majority of injected carbon dioxide is 99.9 percent pure, with the exception of 1,500 tons of a 99.7 percent carbon dioxide steam from the Schwarze Pumpe plant, injected in spring 2011 as a sub-project (GFZ German Research Centre for Geosciences, 2012). The monitoring program at Ketzin involves continuous temperature and pressure monitoring in injection and monitoring wells; geophysical and geochemical monitoring; plume tracking using surface seismic and geoelectric methods; measurements of natural carbon dioxide flux at the surface; subsurface analyses of geology, gases, and fluids; and microbiological monitoring.

At Ketzin, researchers have used both seismic and electrical methods to track the carbon dioxide plume. The monitoring focus area was defined as a 1 km deep block covering a 14 km^2 area around the injection well (CO_2SINK, 2010). Several types of seismic imaging were tested at the site to determine the most appropriate method for longer-term monitoring. Baseline three-dimensional seismic, VSP, and crosswell seismic surveys were taken prior to injection (Giese et al., 2009). In addition, existing two-dimensional seismic data were verified with repeat surveys (Schilling et al., 2009). Crosswell surveys made use of two new monitoring wells. All of the preliminary seismic methods successfully imaged the target formation, though three-dimensional seismic has proved to be more challenging in part because of the relatively small amount of carbon dioxide injected and the heterogeneity of the reservoir (Martens et al., 2012). Seismic monitoring results indicate that after approximately 24,250 tons had been injected (15 months after the injection start date), the carbon dioxide plume remained concentrated around the injection well with a lateral extent of about 300 to 400 m and an approximate thickness of 5 to 20 m (Martens et al., 2012).

Researchers at Ketzin also used ERT to track the carbon dioxide plume. To increase repeatability and minimize disruption to injection activities, all three boreholes at the site were equipped with a permanent vertical electrical resistance array when they were cased. Each array has 15 electrodes spaced 10 m apart (CO_2SINK, 2010). As of 2011, one baseline survey and four follow-up surveys had been conducted. Results indicate that the ERT is sensitive to resistivity changes caused by carbon dioxide migration within the brine-filled reservoir (Schmidt-Hattenberger et al., 2011). The follow-up surveys yielded good lateral and vertical definition of the plume in the regions near the borehole (CO_2SINK, 2010; Schmidt-Hattenberger et al., 2011). One of the downhole arrays is also equipped with a permanent fiber-optic downhole sensor to provide continuous pressure measurements (Giese et al., 2009; CO_2SINK, 2010).

Migration of the two sources of carbon dioxide (i.e., primary source vs. Schwarze Pumpe plant source) were tracked via gas tracer tests using krypton and sulfur hexafluoride, as well as carbon isotopic tracers. These methods were shown to be effective in identifying the source of carbon dioxide and trace the velocity, behavior, and fate of the carbon dioxide in the reservoir (Martens et al., 2012).

Long-term soil gas flux, soil moisture, and temperature measurements have been collected monthly at 20 stations since 2005 (Zimmer et al., 2011). These measurements allow for the detection of potential upward migration of carbon dioxide and leakage to the surface. A comparison of baseline measurements to measurements collected since the start of injection indicate that there has been no change in carbon dioxide soil gas flux. Available data have allowed for an estimation of natural variability in background flux to distinguish biological activity from leakage. The surface monitoring network was expanded in spring 2011 to include eight permanent stations with automated soil gas samplers collecting measurements on an hourly basis. Results from the additional monitoring stations have yet to be released (Martens et al., 2012).

The Ketzin team has also taken measures to monitor both deep and shallow ground water at the site. Existing studies provided background information on deep ground water properties (Förster et al., 2006). Baseline water samples were taken from the injection formation, and three shallow wells (35 to 55 m deep) were drilled to monitor the near-surface hydrology and to deploy electrochemical carbon dioxide detection methods. To monitor the fluids in the injection zone, permanent downhole gas membrane sensors have been deployed in two wells. These sensors use a gas-permeable silicone membrane to separate dissolved gases from formation fluids. A continuous loop of injected argon gas acts as a carrier to transport the separated gases to the surface where they are analyzed by a portable mass spectrometer or collected for further study (Giese et al., 2009; Zimmer et al., 2011). Researchers also monitored the microbiological community in the injection zone to assess any impacts related to changes in the pH of the formation fluids (Morozova et al., 2011).

IV. Weyburn Oil Field

The Weyburn project in Saskatchewan, Canada injects more than 1.8 megatonnes (Mt) of carbon dioxide annually into the Weyburn oil field and, since 2005, in the adjacent Midale oil field, for EOR. The target layers are the 24 m thick, 1,400 m deep hydrocarbon-bearing carbonate beds of the Midale Formation, which are sealed by numerous thick shales (Wilson and Monea, 2004;

Riding and Rochelle, 2005). Regional investigations were conducted over a 200 km by 200 km by 4 km deep block centered on Weyburn Field, while more detailed studies were focused on an area extending 10 km beyond the limits of the planned carbon dioxide flood. Baseline monitoring began in 2000 prior to injection. Since 2000, over 16 Mt of carbon dioxide have been injected at the site (Romanak et al., 2012). While injection is ongoing, the research phase of the project is nearing completion. A report on the first phase (2000-2004) of research activities at the site was issued in 2004 and a report on the research activities of the second and final phase (2005-2011) is scheduled for publication in 2012. The final report is expected to contain recommendations for monitoring technologies and deployments in EOR fields.

Researchers at Weyburn have successfully used time-lapse three-dimensional surface seismic profiling to image the injected carbon dioxide plume (Wilson and Monea, 2004) even though the thickness of the reservoir is at the limit for seismic resolution and the total injection volume was initially small (approximately 2,500 tonnes). Although plume extent could be accurately detected at relatively low saturations, results also suggested that quantitative estimation of plume volume will be considerably more difficult (IEA, 2006). The time-lapse seismic surveys using shear wave splitting showed the potential for imaging mineral dissolution and precipitation along fracture networks, which influenced carbon dioxide distribution within the reservoir (Wilson and Monea, 2004). Along with other monitoring efforts, seismic results indicated that the plume distribution was most strongly influenced by the geologic features (e.g., faults, fractures, porosity) of the reservoir (Wilson and Monea, 2004).

The carbon dioxide plume was also tracked using isotopic and geochemical methods. Produced fluid with the greatest isotopic anomalies corresponded to regions with the highest injection volume (Wilson and Monea, 2004). A geochemical baseline survey was conducted in 2000, and sampling of reservoir fluid every four months from the same 40 wells continued for the next four years. Fluids were analyzed for total alkalinity, pH, calcium, magnesium, resistivity, chlorine, sulfate, aluminum, barium, beryllium, chromium, iron, arsenic, copper, nickel, and zinc (Wilson and Monea, 2004). Samples were also analyzed for the following dissolved gases: carbon monoxide, carbon dioxide, helium, hydrogen, hydrogen sulfide, methane, neon, nitrogen, and oxygen. Results from the geochemical sampling program indicated dissolution trapping of the carbon dioxide within reservoir brines and the dissolution of reservoir carbonates. Due to the lengthy reaction time, geochemical sampling could not confirm mineral trapping (Czernichowski-Lauriol, 2006). Metal concentrations were difficult to interpret. Concentrations of aluminum, barium, beryllium, chromium, and iron increased over the sampling period, but arsenic, copper, nickel, and zinc concentrations fell. These trends have not yet been explained. Good correlation was observed between seismic anomalies, geochemical changes, and areas of the field undergoing the most intense injection (Wilson and Monea, 2004).

Monitoring at Weyburn also includes a passive microseismic monitoring array. Seismic events detected during the monitoring period ranged from -4 to -1 in magnitude (Wilson and Monea, 2004). Such events are similar to or smaller in magnitude than events detected during periods of pure waterflooding. Monitoring also indicated that seismic events within the field area were more closely related to production activities than injection (Wilson and Monea, 2004). In addition to passive seismic monitoring, downhole pressure measurements collected regularly as part of production activities from a sparse subset of production wells were also used to track subsurface pressure. Data were plotted and contoured to create a map of the reservoir pressure field (Wilson and Monea, 2004).

In addition, targeted monitoring and testing were deployed in response to allegations of a carbon dioxide leak at a nearby farm. The farm owners were concerned that there had been a carbon dioxide leak to the surface, based on soil carbon dioxide concentrations and carbon isotope testing (see Petro-Find GeoChem Ltd., 2010). Project operators responded that the injected carbon dioxide isotopic signature was not unique from other, natural sources and that levels of carbon dioxide in the soil were consistent with widely accepted levels for natural settings (PTRC, 2011). The operators and environmental research group IPAC-CO2 Research, Inc. agreed to conduct a full investigation on the site consisting of soil gas analysis, noble gas analysis, and hydrogeologic mapping.

Since baseline data had not been collected at the farm site, the methodology for the study relied on the relationships and relative abundances of selected component soil gases (carbon dioxide, oxygen, nitrogen, argon, nitrogen, argon, C_2-C_5 alkenes, and methane), using a process-based method that does not rely on baseline data. Samples were collected from purpose-built semi-permanent monitoring wells. The results were compared to measurements in soils in similar ecosystems and to soils above an active volcanic complex (Mt. Etna) where carbon dioxide was known to be leaking naturally from a deep source to the surface. Additionally, carbon isotopes were measured. All ratios suggested biogenic processes were controlling soil gas composition. Comparison of carbon isotope composition versus carbon dioxide concentration was used since the isotopic signature of the carbon dioxide alone was not a unique indicator. This test indicated that the isotopic composition was on a mixing line between air and biogenic processes, suggesting leaked carbon dioxide was not needed to explain the carbon isotope abundance in soils at the site (Sherk et al., 2011). Analysis of the alkenes was not undertaken because of the low abundance of methane in the collected samples.

Noble gas levels were also analyzed to indicate the potential for carbon dioxide leakage from injected reservoirs. This method was selected because tracers had not been injected with the carbon dioxide, and carbon isotope signatures were not unambiguous. Using samples collected from existing water, injection, and production wells, researchers were able to demonstrate that the noble gas composition of soil gases closely approximated the noble gas concentration of the ambient air and did not show signs of mixing with crustal-derived noble gases (Sherk et al., 2011).

Finally, a hydrogeologic analysis of the alleged leakage site was conducted. The investigation used soil samples gathered during the drilling of the soil gas monitoring wells as well as other sources. This portion of the study reached three findings: the shallow ground water at the site met Saskatchewan's Drinking Water Quality Standards during the period of sample collection, no anomalous features were found during the investigation that could act as previously unknown conduits for carbon dioxide movement, and films on ponds at the site were of biologic origin and not evidence of hydrocarbon seepage (Sherk et al., 2011).

Relying on the fixed gas relationship results, the noble gas results, and the hydrogeologic analysis, the study concluded that carbon dioxide had not leaked from the injection zone or injection wells to the surface at the farmstead.

V. West Pearl Queen Project

The West Pearl Queen project is a completed pilot-scale project that injected 22,090 tons of carbon dioxide into the West Pearl Queen oil field in Hobbs, New Mexico during 2002 and 2003 (Cooper et al., 2008). Carbon dioxide was injected via a single well into a 12 m thick depleted sandstone target formation, the Shattuck Sandstone Member of the Permian Queen Formation. The unit, which is at a depth of 1,372 m, is overlain by dolomite and shale confining formations. Beneath the formation is a nearly continuous blanket of caliche with varying thickness of 0 to 5 ft (Westrich et al., 2001; Wells et al., 2007).

At the site, four existing wells were repurposed for the project: one for use as an injection well and three for monitoring. The injection well had been shut-in since 1998, and the monitoring wells had previously been used as two produced water injection wells and one production well. The carbon dioxide was vented from the injection well 6 months after injection was completed. Monitoring studies were limited to a 1 square mile region surrounding the injection well. Laboratory analyses and numerical modeling were also completed to support the field testing program. Samples of injection zone fluids were taken 6 months post injection as well as during the carbon dioxide venting process. In addition to sample collection, the volume of produced fluid during venting was also recorded (Pawar et al., 2006).

Researchers used tracer additions and seismic methods to track the carbon dioxide plume. Three unique perfluorocarbon tracers were co-injected sequentially with the carbon dioxide as 12 hour slugs at one-week intervals (Wilson et al., 2005; Myers et al., in press). Following injection, 40 capillary adsorption tube samplers were deployed in a radial pattern surrounding the injection well to monitor soil gas. The capillary adsorption tube samplers were collected and redeployed several times. To avoid sample contamination (which could inadvertently lead to a false positive identification of a tracer), the injection team and the sampling team were based 130 km apart, and the teams avoided visiting the site on the same day (Myers et al., in press).

Within a few days of injection, tracers were detected at sampling locations at a depth of approximately 2 m, 50 m away from the injection well. The tracers were detected for several years after venting, indicating that injected carbon dioxide continuously escaped from the injection zone. The volume of leakage was estimated to be 0.0085 percent of the total amount of carbon dioxide sequestered per year (Wilson et al., 2005; Wells et al., 2007). Although many leakage pathways are possible, investigation targeted leakage along the injection well casing as the most likely leakage path given the timing, amount, and distribution of the detected carbon dioxide (Wells et al., 2007; Wilson et al., 2010). P-wave images from seismic surveying identified a pool of carbon dioxide near the base of the injection well, but detection capabilities were not strong enough to detect the carbon dioxide leak discovered through tracer methods (Pawar et al., 2006). Importantly, only the P-wave data were analyzed; further analysis of the seismic images may help elucidate changes in seismic data related to injection (Cooper et al., 2008). Remote sensing and ground-penetrating radar were also used in conjunction with tracers to determine possible leakage pathways. These methods found fractures and faults in the caliche beneath the injection area and northwest of the injection well, which may have facilitated leakage. Thin (less than 1 ft) areas of caliche may have also contributed to leakage southwest of the injection well. Another potential tracer transport mechanism is atmospheric transport, though the locations of tracer leakage could not be explained by this route of transport (Wilson et al., 2005).

Researchers also monitored injection zone pressure at the site. Following the injection phase, a downhole pressure sampler was deployed at the bottom of the injection well. Pressure measurements were taken intermittently over a six-month period (Pawar et al., 2006). For the first month after shut-in, pressure readings decreased, suggesting that the formation was accommodating the injected carbon dioxide (Wells et al., 2007). After 30 days, equilibrium pressure was reached. The equilibrium pressure was much higher than modeled predictions (Pawar et al., 2006). A post-test assessment of the geology of West Pearl Queen was undertaken to better understand what factors contributed to higher-than-expected injection pressures leading to lower carbon dioxide injection rates. Research from this study indicated that the poor interconnectivity between individual component beds of the Shattuck reservoir sandstones, as well as heterogeneities in the formation (e.g., channels, thrust fault, facies changes, and local bed thickenings), were contributors (Cooper et al., 2008).

Carbon dioxide plume monitoring was also conducted via geophysical methods. A baseline three-dimensional seismic survey was followed with a repeat survey six months after injection (just prior to venting) to image the carbon dioxide plume (Pawar et al., 2006). Microseismic monitoring was also deployed at the site; no significant microseismic events were detected. The migration of injected fluids between wells through the heterogeneous injection zone was found to be incorrectly predicted by preliminary modeling. The localization of injected carbon dioxide at the base of the injection well and a delay between injection and arrival at the nearby injection well were also observed; injectate took three years to arrive at a monitoring well only 0.25 miles away from the injection well (Cooper et al., 2008).

VI. In Salah Natural Gas Fields

The In Salah project is a commercial-scale GS project centered on a group of active natural gas production fields at Krechba, in central Algeria. Carbon dioxide is separated from produced gas to meet market requirements for natural gas purity. The carbon dioxide stream (which is approximately 98 percent pure carbon dioxide) is being re-injected to meet the operator's environmental sustainability standards (BP, 2008; Wright, 2007). The target formation is a heterogeneous, low-permeability sandstone that is approximately 20 m thick and 1,800 m deep (Wright, 2007). The sandstone is part of a gas-containing anticline, and the carbon dioxide is injected through three horizontal injection wells (BP, 2008).The purpose of the project is to inject up to 1 Mt of carbon dioxide per year, beginning in 2004, while testing and developing techniques to demonstrate verifiable carbon dioxide sequestration in conjunction with commercial natural gas production (BP, 2008; Michael et al., 2009; Riddiford et al., 2004).

Monitoring activities at the site are overseen by a Joint Industry Project (JIP), an international effort supported by joint venture partners BP, Sonatrach, and Statoil, as well as USDOE and the European Union Directorate General for Research and Innovation. A monitoring plan for the project was developed based on a cost-benefit assessment of monitoring options; this assessment was refined after initial testing and a quantitative risk assessment was completed after four years of injection and monitoring to further update the project's development plan (Wright et al., 2010). Leakage from legacy wells in the production field was identified as the highest risk for leakage out of the target formation. JIP monitoring activities are organized into phases, with Phase I completed in 2010. During Phase II, monitoring techniques that were proven to be effective during Phase I will be implemented on a routine basis by the operators, while JIP efforts will focus on emerging technologies and improved modeling techniques (ISG, 2010).

Remote satellite imaging of surface deformation is one of the technologies used to track the plume at In Salah. Investigations focus on a 25 km by 8 km area defined by both the gas leg and the immediately underlying aquifer section of the reservoir anticline. During the initial planning phase, researchers expected that satellite tracking would be of little use at In Salah because of the depth and thinness of the target formation. However, modeling conducted by Lawrence Berkeley National Laboratory (LBNL) using the TOUGH-FLAC simulator for multi-phase fluid flow and geomechanics, indicated that injection at the site could potentially result in several centimeters of surface elevation change (Vasco et al., 2008; Rutqvist et al., 2010). Results of this magnitude are sufficient for satellite monitoring. The site is also ideally suited for satellite monitoring because site is remote and the land surface is hard and has little vegetation. Between 2004 and 2007, 17 passes were made to collect satellite data. As of 2008, data collection was ongoing at a rate of one image every 26 days, with a pixel size of 3 square meters (Mathieson et al., 2008).

Satellite images show an excellent correlation between areas of injection and uplift. Elevation increases of up to approximately 20-25 mm were observed near the injectors, enough for successful imaging. There is also good correlation between areas of extraction and subsidence. The images indicate a northwest/southeast elongating plume, which mirrors the orientation of fracturing in the injection zone (Mathieson et al., 2008). Satellite imaging also alerted site operators to rapid migration of the carbon dioxide plume toward a suspended appraisal well at the site. Later monitoring at the suspended well revealed that some carbon dioxide was reaching the surface, and more detailed investigations led to the detection of a previously uncharacterized fracture near the well (Ringrose et al., 2009; Statoil, 2009). Tracers co-injected with the carbon dioxide were used to verify that the leaking carbon dioxide at the abandoned well originated from a nearby injector (Ringrose et al., 2009). Subsequently, the leaking well was permanently sealed and abandoned, closing the communication pathway that remained following suspension of the well.

Three-dimensional seismic surveys are also considered an important technology in the In Salah monitoring plan and are used to help track the spread of the carbon dioxide plume (Wright, 2006). A baseline seismic survey was conducted in 1997, and a repeat survey was conducted in 2009 in the northern part of the field (BP, 2008). Data from the repeat survey were not yet available when this document was developed. An array of downhole three-component geophones has also been deployed at one well for microseismic monitoring. This monitoring began in August 2009 and very low levels of microseismic events (zero to one events per day) were recorded until mid-2010, when the frequency of events increased. Daley et al. (2012) concluded that these preliminary results were sufficient to warrant further investment in microseismic monitoring at the site. In addition, to track subsurface pressure, the active injection and production wells are continually monitored for pressure at the wellhead (ISG, 2009). Ground water is monitored by pumping and sampling of six dedicated shallow aquifer monitoring wells.

Near-surface soil/air monitoring has also been conducted at In Salah. Initial baseline soil gas measurements were taken in 2004, and a second round of measurements was taken in 2009

(Jones et al., 2011). During this second study, surface gas measurements were taken in March 2009 using a vehicle-mounted open-path laser system. Researchers also collected soil gas samples for laboratory analysis and made in situ soil gas measurements with instruments that used IR analyzers for carbon dioxide. Carbon dioxide flux measurements were also made at this time, and buried probes were deployed to collect data on radon, which may act as a natural tracer. Additional measurements were made in November 2009, in support of a baseline study of biological activity. The surface air and soil gas results were affected by poorly constrained natural (diurnal and seasonal) variations and interference from dust, vehicle exhaust, and other factors. The only clearly anomalous values were found around the abandoned well described above, due to the previous leak at the site (Jones et al., 2011).