United States Environmental Protection Agency

Geologic Sequestration of Carbon Dioxide

Underground Injection Control (UIC) Program Class VI Well Site Characterization 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.

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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 (GHG MRR), are not within the scope of this document.

Executive Summary

EPA's *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* are 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 minimum federal technical criteria for Class VI injection wells for the purpose of protecting underground sources of drinking water (USDWs). This document is part of a series of technical guidance documents designed to support owners or operators of Class VI wells and the UIC Program permitting authorities.

Site characterization is critical to operating safe and effective geologic sequestration (GS) projects. The proper siting of a Class VI injection well is the foundation for successful GS operations. Site characterization identifies potential risks and eliminates unacceptable sites (e.g., sites with transmissive faults or fractures that would impair containment). Key aspects of an appropriate GS site, per 40 CFR 146.83, include geologic formations that provide adequate storage capacity to store the injected carbon dioxide and a competent confining zone that will contain the injected carbon dioxide. Class VI well owners or operators also must identify additional confining zones, if required by the UIC Program Director.

The Class VI Rule also requires owners or operators of Class VI wells to perform, among other activities, a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that wells are sited in suitable locations [40 CFR 146.82(a) and (c)]. As part of the site characterization required to be documented in a Class VI permit application, owners or operators of Class VI wells must submit maps and geologic cross sections describing subsurface geologic formations as well as the general vertical and lateral limits of all USDWs at the proposed GS site [40 CFR 146.82(a)]. Data and information collected during site characterization are used in the development of injection well construction and operating plans; provide inputs for the computational model that estimates the extent of the injected carbon dioxide plume and related pressure front; and establish baseline information to which geochemical, geophysical, and hydrogeologic site monitoring data collected over the life of the injection project can be compared.

This *UIC Program Class VI Well Site Characterization Guidance* describes those data and information that are typically used to characterize the geology of a site, including methods for measuring or estimating important geologic parameters. The introductory section of this guidance provides an overview of the Class VI Rule, specifically with regard to geologic siting requirements. The second section describes the site characterization data needed to obtain a permit for the construction of a Class VI well. The third section addresses certain aspects of site characterization activities that involve the synthesis of geologic, hydrogeologic, geochemical, and geomechanical data in order to demonstrate that the project site is suitable for injection (i.e., has an injection zone capable of receiving the anticipated volume of carbon dioxide and a confining zone(s) capable of containing the plume and pressure front). The fourth section addresses requirements applicable to drilling and completion of the injection well that must be met before operation may be authorized, pursuant to 40 CFR 146.82(c) and 146.87. In each section, the guidance describes options for meeting the Class VI Rule requirements and the types of information recommended to be submitted.

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Acronyms and Abbreviations

2D	Two-dimensional
3D	Three-dimensional
AAPG	American Association of Petroleum Geologists
ANN	Artificial neural networks
AoR	Area of review
API	American Petroleum Institute
BSE	Backscattered electron
CERCLIS	Comprehensive Environmental Response, Compensation, and Liability Information System
CERI	Center for Earthquake Research and Information
CFR	Code of Federal Regulations
CGS	Centimeter gram second system
CO_2	Carbon dioxide
CR	Complex resistivity
CSAMT	Controlled source audio-frequency magnetotellurics
CT	Computerized tomography
DADN	Difference analysis with data normalization
DOE	United States Department of Energy
EGR	Enhanced gas recovery
EM	Electromagnetic
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
ERT	Electrical resistivity tomography (electroresistive tomography)
FBP	Formation breakdown pressure
FEMA	Federal Emergency Management Agency
FMI	Formation microresistivity image
FPP	Fracture pumping pressure
GEM	Global Earthquake Model
GHG MRR	Greenhouse Gas Mandatory Reporting Rule
GIS	Geographic information system
GPR	Ground penetrating radar
GS	Geologic sequestration
ICIS	Integrated Compliance Information System
ICP/AES	Inductively coupled plasma/atomic emission spectrometry

ICP/MS	Inductively coupled plasma/mass spectrometry
IFT	Interfacial tension
IGIP	Initial gas in place
IP	Induced polarization
LOP	Leak-off point
LOT	Leak-off test
LWD	Logging while drilling
M	Mobility ratio
Mt	Megatonne
NERSL	National Energy Research Seismic Library
NETL	National Energy Technology Laboratory
NML	Nuclear magnetism logging
NMR	Nuclear magnetic resonance
NOAA	National Oceanic and Atmospheric Administration
NWIS	National Water Information System
OGIP	Original gas in place
OOIP	Original oil in place
pAVAZ	P-wave amplitude variation with offset and azimuth, also referred to as pAVOA
Pe	Capillary entry pressure
PGIP	Producible gas in place
PIA	Petrographic image analysis
PISC	Post-injection site care
SC	Specific conductivity
SCAL	Special core analysis
SDWA	Safe Drinking Water Act
SEI	Secondary electron imaging
SEM	Scanning electron microscope (or microscopy)
SGR	Shale gouge ratio
SP	Self potential (when referring to geophysical techniques)
SP	Spontaneous potential (when referring to logging)
TDS	Total dissolved solids
TOC	Total organic carbon
UIC	Underground Injection Control
USBM	United States Bureau of Mines
USDW	Underground source of drinking water
USGS	United States Department of the Interior, United States Geological Survey

VSP	Vertical seismic profile
XLOT	Extended leak-off test
XRD	X-ray diffraction
XRF	X-ray fluorescence

Definitions

Key to definition sources:

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

Area of Review (AoR) means the region surrounding the geologic sequestration 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.[1]

Brine means water that has a large quantity of salt, especially sodium chloride, dissolved in it. Large quantities of brine are often produced along with oil and gas. Water having high total dissolved solids (TDS) content.[2]

Buoyancy refers to the upward force on one phase (e.g., a fluid) produced by the surrounding fluid (e.g., a liquid or a gas) in which it is fully or partially immersed, caused by differences in pressure or density.[3]

Capillary pressure refers to the difference of pressures between two phases existing in a system of interconnecting pores or capillaries. The difference in pressure is due to the combination of surface tension and curvature in the capillaries.[5]

Carbon dioxide plume means the extent underground, in three dimensions, of an injected carbon dioxide stream.[1]

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 part 146] does not apply to any carbon dioxide stream that meets the definition of a hazardous waste under 40 CFR part 261.[1]

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 EOR/EGR aquifer exemption pursuant to 40 CFR 146.4 and 144.7(d).[4]

Computational model means a mathematical representation of the injection project and relevant features, including injection wells, site geology, and fluids present. For a GS project, site-specific geologic information is used as input to a computational code, creating a computational model that provides predictions of subsurface conditions, fluid flow, and carbon dioxide plume and pressure front movement at that site. The computational model comprises all model input and predictions (i.e., output).[5]

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).[1]

Corrective action means the use of Director-approved methods to ensure that wells within the AoR do not serve as conduits for the movement of fluids into USDWs.[1]

Cratonic means pertaining to the old, stable lithosphere in the interiors of continents.[5]

Drilling mud means a heavy suspension used in drilling an "injection well," introduced down the drill pipe and through the drill bit.[6]

Dynamic models refers to a method or methods for estimating carbon dioxide storage capacity after initiation of carbon dioxide injection, including decline curve analysis, material balance, and reservoir simulation.[5]

Effective permeability means the permeability of one fluid when more than one fluid phase is present.[5]

Enhanced Oil or Gas Recovery (EOR/EGR) typically means, the process of injecting a fluid (e.g., water, brine, or carbon dioxide) into an oil or gas bearing formation to recover residual oil or natural gas. The injected fluid thins (decreases the viscosity) and/or displaces extractable oil and gas, which is then available for recovery. This is also used for secondary or tertiary recovery.[3]

Equation of state refers to an equation that expresses the equilibrium phase relationship between pressure, volume and temperature for a particular chemical species.[5]

Fluid means any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas or other form or state.[6]

Formation or geological formation means a layer of rock that is made up of a certain type of rock or a combination of types.[3]

Geochemical characterization means to study the chemistry of the formation fluids and solids (rock) and to identify potential chemical interactions among the injectate (carbon dioxide), formation fluids, and solids.[5]

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.[1]

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 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 EOR/EGR 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.[1]

Geomechanical characterization means to study the rock mechanical characteristics associated with carbon dioxide containment such as fault and reservoir rock stability and confining zone integrity.[5]

Geophysical surveys refers to the use of geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic (EM) surveys or well logging methods such as gamma ray and spontaneous potential) to characterize subsurface rock formations.[3]

Heterogeneity refers to the spatial variability in the geologic structure and/or physical properties of the site.[5]

Hysteresis means the phenomenon where the response of a system depends not only on the present stimulus, but also on the previous history of the medium. For example, in a GS project, relative permeability, capillary pressure, and residual trapping will depend upon the saturation history of the formation (i.e., injection vs. post-injection phase).[5]

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.[1]

Injectivity is the pressure differential over existing reservoir pressure required to inject a unit volume of fluid in a given unit of time. It is typically expressed as psi/bbl/day (psi per barrel per day) but can be expressed in any combination of pressure, volume, and time units. [5]

In situ stresses refers to the three principal stresses (vertical stress, maximum horizontal stress, and minimum horizontal stress) commonly used to characterize the geomechanical model.[5]

Intracratonic means located in an area above old, stable lithosphere, usually in the interiors of continents far away from plate boundaries.[5]

Intrinsic permeability refers to a parameter that describes properties of the subsurface that impact the rate of fluid flow. Larger intrinsic permeability values correspond to greater fluid flow rates. Intrinsic permeability has units of area (distance squared).[5]

Irreducible water saturation refers to the smallest amount of remaining water in a core sample after forced displacement by another fluid.[5]

Lithology means the description of rocks, based on color, mineral composition, and grain size.[3]

Mineralogy, petrology, and solid-phase chemistry refers to the composition of the solids in an aquifer, including the minerals, rock types and their origins, and bulk chemical composition.[5]

Mud log means data collected from drilling mud as it circulates. It produces a record of the different types of data collected when drilling a well, such as the rate of drilling, the rock types in the cuttings, and the presence of hydrocarbons.[5]

Parameter means a mathematical variable used in governing equations, equations of state, and constitutive relationships. Parameters describe properties of the fluids present, porous media, and fluid sources and sinks (e.g., injection well). Examples of model parameters include intrinsic permeability, fluid viscosity, and fluid injection rate.[5]

Pore throat radius means the radius of the opening to a pore in a rock.[5]

Porosity means the percentage of rock consisting of void space.[5]

Post-injection site care means appropriate monitoring and other actions (including corrective action) needed following cessation of injection to ensure that USDWs are not endangered, as required under 40 CFR 146.93.[1]

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.[1]

Relative permeability refers to a factor, between 0 and 1, that is multiplied by the intrinsic permeability of a formation to compute the effective permeability for a fluid in a particular pore space. When immiscible fluids (e.g., carbon dioxide, water) are present within the pore space of a formation, the ability for flow of those fluids is reduced, due to the blocking effect of the presence of the other fluid. This reduction is represented by relative permeability.[5]

Reserve means the estimated volume available for carbon dioxide storage in the injection zone, considering technological, economic, and regulatory constraints and limitations. Reserve estimates can be considered a subset of resource estimates.[5]

Resource means the estimated volume available for carbon dioxide storage in the injection zone.[5]

Site closure means the point/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 is released from post-injection site care responsibilities.[1]

Skin factor or skin effect refers to the restrictions to flow in the near-well bore region, typically associated with damage during drilling and well operations.[5]

Static models refers to the methods for estimating carbon dioxide storage capacity prior to startup of injection and includes volumetric and compressibility methods.[5]

Storage capacity means the pore volume within the injection zone available for carbon dioxide storage.[5]

Stratigraphy means the sequence of rock strata, or layers. This generally refers to layers of sedimentary or igneous rocks.[5]

Supercritical fluid means a fluid above its critical temperature (31.1ºC for carbon dioxide) and critical pressure (73.8 bar for carbon dioxide).[5]

Tensile strength refers to the maximum force an element can take in tension before it breaks.[5]

Total dissolved solids (TDS) means the total dissolved (filterable) solids as determined by use of the method specified in 40 CFR part 136.[6]

Transmissibility means a coefficient associated with Darcy's law that characterizes flow through porous media. It is equal to the coefficient of permeability (hydraulic conductivity) multiplied by the thickness of the formation.[5]

Transmissive fault or fracture means a fault or fracture that has sufficient permeability and vertical extent to allow fluids to move between formations.[1]

Underground Injection Control Program refers to the program EPA, or an approved state, is authorized to implement under the Safe Drinking Water Act (SDWA) that is responsible for regulating the underground injection of fluids by injection wells. This includes setting the federal minimum requirements for construction, operation, permitting, and closure of underground injection wells.[5]

Underground Injection Control Program (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.[2]

Underground Source of Drinking Water (USDW) means an aquifer or its portion which supplies any public water system; or which contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/l total dissolved solids; and which is not an exempted aquifer.[6]

Well bore refers to the hole that remains throughout a geologic (rock) formation after a well is drilled.[5]

Wireline refers to a wire or cable that is used to deploy tools and instruments downhole and that transmits data to the surface.[5]

Workover refers to any maintenance activity performed on a well that involves ceasing injection and removing the wellhead.[5]

1. Introduction

Site characterization is a long-standing requirement of the Underground Injection Control (UIC) Program to ensure safe deployment of injection operations and the protection of underground sources of drinking water (USDWs). The U.S. Environmental Protection Agency's (EPA's) *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration (GS) Wells*, found at 75 FR 77230, December 10, 2010, and codified in the U.S. Code of Federal Regulations [40 CFR 146.81 *et seq*.], are referred to as the Class VI Rule. The Class VI Rule requires owners or operators of wells used to inject carbon dioxide for GS to identify the presence of suitable geologic characteristics at a proposed site to ensure the protection of USDWs during and following injection activities.

Site characterization for Class VI permitting focuses on demonstrating that a proposed project site has a suitable injection zone to receive the carbon dioxide and a confining zone that will prevent fluid movement out of the injection zone as described under 40 CFR 146.83. Owners or operators must gather the data necessary to demonstrate site suitability and submit this with a Class VI permit application to be evaluated by the UIC Program Director prior to receiving authorization to construct the well [40 CFR 146.82(a)], and must update and gather more detailed site-specific information and submit this prior to receiving authorization for injection [40 CFR 146.82(c)].

The site characterization process typically includes a general characterization of regional and site geology, followed by detailed characterization of the injection zone and confining zones. The more general characterization includes data on the regional geology and hydrogeology, supported by maps, cross sections, and other available data. The more detailed information focuses on the proposed project site and involves submission of data on stratigraphy, structural geology, hydrogeology, geomechanical properties, and geochemistry. The initial stage includes compiling pre-existing and/or new information, maps, cross sections, geochemical and petrophysical data, and geophysical or remote sensing information as described under 40 CFR 146.82(a). Final site characterization data will be collected as the injection well is drilled, core samples are taken and analyzed, and logs and tests are performed, as described under 40 CFR 146.82(c).

In addition to being essential to USDW protection, thorough site characterization is a necessary element of selecting viable GS sites. EPA expects that selecting GS sites will be analogous to the process by which oil and gas recovery projects are sited—from a "big picture" regional evaluation of prospective resources that relies primarily on existing data, to more detailed evaluations of prospects that appear, based on preliminary data, to be promising sites. These detailed evaluations involve the use of the same logging, testing, and modeling techniques needed to perform site characterizations that can meet the requirements of the Class VI Rule (NETL, 2010).

1.1. Overview of Class VI Rule Requirements

The Class VI Rule, at 40 CFR 146.83, establishes minimum criteria for the siting of Class VI wells. Specifically, Class VI wells must be located in areas with a suitable geologic system, including: (1) the presence of an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream; and (2) the presence of confining zones that are free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the carbon dioxide stream and displaced formation fluids and allow injection without initiating or propagating fractures [40 CFR 146.83(a)]. Additionally, at the UIC Program Director's discretion, owners or operators may be required to identify and characterize additional confining zones to ensure USDW protection, impede vertical fluid movement, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation [40 CFR 146.83(b)].

Owners or operators must demonstrate that a proposed site is suitable for GS by performing detailed site characterization and submitting extensive geologic data to the UIC Program Director. These data, described at 40 CFR 146.82(a), are necessary to demonstrate that the well will be sited in an area with a suitable geologic system that will ensure USDW protection and meet the requirements of 40 CFR 146.83. The Class VI Rule specifies distinct requirements for information to be submitted with the permit application and before well construction is approved at 40 CFR 146.82(a), and information to be submitted before operation of the well is authorized at 40 CFR 146.82(c).

Site characterization is an iterative process. Site characterization data are submitted to the UIC Program Director to fulfill the requirements for a Class VI permit application [40 CFR 146.82(a)] before well construction is approved. Pursuant to the requirements at 40 CFR 146.82(c), the data must be updated and refined before operation of the well is authorized based on the results of the formation testing program required at 40 CFR 146.82(a)(8) and 146.87 that is executed during injection well drilling and completion.

The types of site characterization information specified by the Class VI Rule that must be provided with a Class VI well permit application include:

- Maps and cross sections of the area of review (AoR) [40 CFR 146.82(a)(3)(i) and 146.82(a)(2)];
- The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AoR, along with a determination that they will not interfere with containment [40 CFR 146.82(a)(3)(ii)];
- Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) and on lithology and facies changes [40 CFR 146.82(a)(3)(iii)];
- Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)];

- Information on the seismic history of the area, including the presence and depths of seismic sources, and a determination that the seismicity will not interfere with containment [40 CFR 146.82(a)(3)(v)];
- Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area [40 CFR 146.82(a)(3)(vi)];
- Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells, and springs within the AoR, their positions relative to the injection zone(s), and the direction of water movement (where known) [40 CFR 146.82(a)(5)]; and
- Baseline geochemical data on subsurface formations, including all USDWs in the AoR [40 CFR 146.82(a)(6)].

The types of site characterization information specified by the Class VI Rule that must be provided for the UIC Program Director to review and approve the operation of a Class VI well include:

- Any relevant updates to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, based on data obtained during logging and testing of the well [40 CFR 146.82(c)(2)];
- Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s) [40 CFR 146.82(c)(3)];
- The results of formation testing [40 CFR 146.82(c)(4)]; and
- All available logging and testing program data on the well required by 40 CFR 146.87 [40 CFR 146.82(c)(7)].

Owners or operators are expected to take full advantage of existing site characterization data to fulfill the requirements at 40 CFR 146.82. However, a stratigraphic well may need to be drilled in some cases (e.g., if adequate data are not already available). If owners or operators need to drill a stratigraphic well, they may consider ultimately using it for injection or monitoring.

Owners or operators should keep in mind that if the AoR delineation or any of the project plans require significant changes based on the final site characterization data, the Class VI permit would have to be modified to incorporate these changes before injection can be authorized [40 CFR 144.39]. Depending on the extent of the modifications, the UIC Program Director may need to re-initiate the public notice process. To avoid any potential delays associated with the permit modification process, EPA encourages owners or operators to collect as much site-specific data as possible before submitting the initial Class VI permit application. Additional information on the Class VI permitting process and how UIC Program Directors may evaluate the site characterization submittals is presented in the *UIC Program Class VI Implementation Manual for State Directors*.

1.2. Overview and Purpose of this Guidance

The purpose of this guidance is to describe the data needs, process, and procedures for conducting a geologic assessment that meets the requirements of the Class VI Rule at 40 CFR 146.82 and 146.83. This document provides guidance on the types of information to collect and submit with a Class VI injection well permit application as well as where and how such information might be obtained. Illustrative examples of some of the required information are in the Appendix to this document.

This guidance document is written to assist Class VI injection well owners or operators, parties that may conduct the geologic siting activities on behalf of owners or operators, and the UIC Program permitting authorities who will evaluate Class VI permit applications. This guidance can also help owners or operators who hire contractors to perform some or all of the required site characterization activities understand, as signers of the permit application, all of the information that is submitted. Likewise, owners or operators are encouraged to share this guidance document with contractors so that they understand the permitting authority's expectations for the data submitted.

It is important to note that not all sites will be suitable for GS. This guidance provides considerations for determining when issuing a Class VI permit is or might not be appropriate, or when more data may be needed to make a determination regarding the suitability of a site. EPA encourages owners or operators to review the considerations in this guidance and discuss the data being collected with the UIC Program Director throughout the site characterization process. Table 1-1 presents the activities owners or operators undertake as part of the site evaluation/characterization process (based on the requirements of 40 CFR 146.82), the corresponding Class VI Rule requirement, and the section of this guidance that describes how owners or operators can collect this information and submit it to demonstrate to the UIC Program Director that the site is appropriate for GS.

Table 1-1: Site Characterization Activities in the Class VI Rule

Activity	Class VI Rule Requirement	Guidance Section
Regional evaluation		
Characterize regional geology and hydrogeology and local structural geology	Maps and cross sections of the AoR [40 CFR 146.82(a)(3)(i)]. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area [40 CFR 146.82(a)(3)(vi)].	2.3.1 2.1
Gather information on all wells, etc.	Map showing the injection well, the applicable AoR, and faults, if known or suspected [40 CFR 146.82(a)(2)].	2.2
Study seismic history	Information on the seismic history of the area, including the presence and depths of seismic sources [40 CFR 146.82(a)(3)(v)].	2.3.7

Activity	Class VI Rule Requirement	Guidance Section
Detailed analysis		
Study faults and fractures in the AoR	The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AoR and a determination that they would not interfere with containment [40 CFR 146.82(a)(3)(ii)].	2.3.2
Collect data on the depth, areal extent, and thickness of the injection and confining zones, and facies changes	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions [40 CFR 146.82(a)(3)(iii)].	2.3.3, 3.1
Characterize mineralogy of the injection and confining zones	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions [40 CFR 146.82(a)(3)(iii)].	2.3.4
Characterize porosity, permeability, and capillary pressure of the injection and confining zones	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions [40 CFR 146.82(a)(3)(iii)].	2.3.5
Perform geomechanical characterization	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)].	2.3.6
Characterize hydrology and hydrogeology of the AoR	Maps and stratigraphic cross sections indicating all USDWs, water wells and springs within the AoR, their positions relative to the injection zone(s), and the direction of water movement, where known [40 CFR 146.82(a)(5)].	2.3.8
Characterize geochemistry	Baseline geochemical data on subsurface formations [146.82(a)(6)].	2.3.9
Perform geophysical characterization	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions [40 CFR 146.82(a)(3)(iii)].	2.3.10
During/after well drilling		
Update site characterization data based on pre-injection logs and tests	Any relevant updates, based on data obtained during logging and testing of the well and the formation, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations [40 CFR 146.82(c)(2)].	4
Perform formation testing	The results of the formation testing program [40 CFR 146.82(c)(4)].	4.1

Activity	Class VI Rule Requirement	Guidance Section
Analyze cores	Take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and submit a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information [per 40 CFR 146.87(b), required at 146.82(c)(7)].	4.2
Characterize injection zone fluids	Record the fluid temperature, pH, specific conductivity, reservoir pressure, and static fluid level of the injection zone(s) [per 40 CFR 146.87(c), required at 146.82(c)(7)].	4.3
Calculate fracture pressures	Determine or calculate fracture pressure and other physical and chemical characteristics of the injection and confining zone(s) and physical and chemical characteristics of the formation fluids in the injection zone(s) [per 40 CFR 146.87(d), required at 146.82(c)(7)].	4.4
Characterize injection zone hydrogeologic properties	Prior to operation, conduct a pressure fall-off test and a pump test or injectivity tests to verify hydrogeologic characteristics of the injection zone(s) [per 40 CFR 146.87(e), required at 146.82(c)(7)].	4.5
Analyze carbon dioxide stream compatibility	Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well [40 CFR 146.82(c)(3)].	3.3

This guidance assumes that readers are familiar with many of the available techniques used in geologic site characterizations and their use. Thus, descriptions of these techniques in this document are minimal. The Appendix provides background information on a number of these technical topics, along with an extensive list of references.

1.3. Relationship to Other Class VI Activities

This guidance document focuses on collecting the geological, physical, and chemical data necessary to support Class VI permit determinations during the pre-injection phase of a GS project. Data obtained during the site characterization process will also support other permit application and site operation activities. For example:

- Data on rock and fluid properties can inform the design and calibration of AoR delineation models;
- Information on injection zone and/or confining zone mineralogy, fluids, and properties can inform proper well construction and pre-injection testing;
- Data on the confining zone fracture pressure and storage capacity can inform setting protective operating limits; and
- Water quality and geophysical profiling data can serve as a baseline for the testing and monitoring that will take place during the operational phase of the project.

These cross-linkages between guidance documents are noted in the text where appropriate.

This guidance document is part of a series of technical guidance documents developed to provide information and possible approaches for addressing various aspects of permitting and operating a Class VI injection well. A number of UIC Class VI Program companion guidance documents focus on other steps in the process. These documents include:

- The *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* explains how site data will inform computational modeling of the AoR;
- The *UIC Program Class VI Well Construction Guidance* describes how to construct injection wells using materials that are compatible with the carbon dioxide and subsurface conditions;
- The *UIC Program Class VI Well Testing and Monitoring Guidance* describes how baseline geochemical and other site data will inform appropriate site monitoring;
- The *UIC Program Class VI Well Project Plan Development Guidance* explains how site data can inform development of the required project plans; and
- The *UIC Program Class VI Well Injection Depth Waivers Guidance* provides special considerations and additional requirements for evaluating sites where injection into non-USDWs above or between USDWs is planned.

These guidance documents are intended to complement each other and to assist owners or operators in preparing permit applications that satisfy the requirements of the Class VI Rule and are tailored to the characteristics of individual sites. The material that these guidance documents encompass reflects the linkages among the different steps and stages of a GS operation as shown in Figure 1-1.

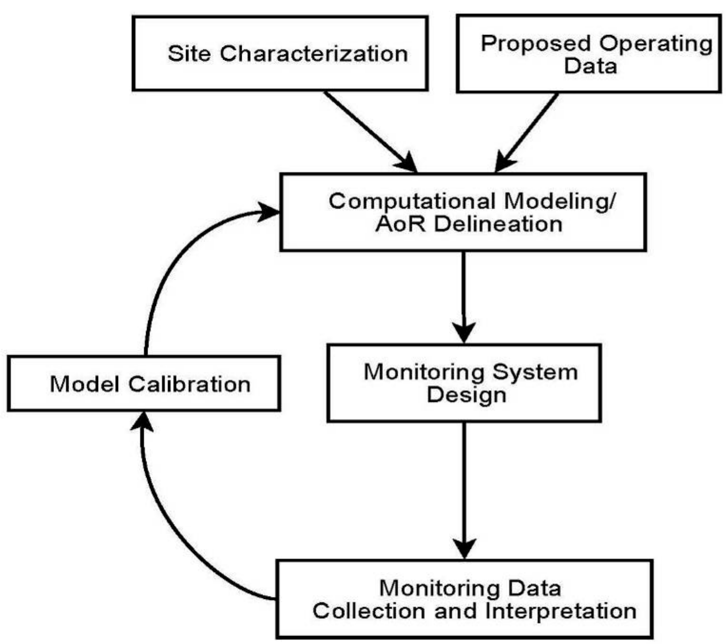

Figure 1-1: Flow Chart Showing Relationships among Site Characterization, Modeling, and Monitoring for a GS Project

1.4. Organization of this Guidance

Following the introduction (Section 1), this guidance document is organized as follows:

- Section 2, Activities Performed Prior to the Construction of a Class VI Well, presents the activities that owners or operators will perform before an injection well may be drilled (i.e., to apply for a Class VI permit). Information generated from these activities will meet the requirements of 40 CFR 146.82(a)(2), (3), (5), and (6).
- Section 3, Data Synthesis for Demonstration of Site Suitability, provides considerations and recommendations for how owners or operators can synthesize the information collected to demonstrate that the site meets the requirements of 40 CFR 146.83, is acceptable to the UIC Program Director, and is suitable for a Class VI permit. This section describes some of the "big picture" questions about a proposed site that will need to be answered through the site characterization process. Owners or operators should consider these as they plan to collect the site data that will inform their permit application.
- Section 4, Activities Performed Prior to the Operation of a Class VI Well, presents activities that owners or operators will perform before injection may be authorized. The information obtained from these activities will meet the site characterization-related requirements of 40 CFR 146.82(c)(2)–(4) and (7), and 146.87(b)–(e).

2. Activities Performed Prior to Construction of a Class VI Well

The Class VI Rule, at 40 CFR 146.82(a), requires Class VI permit applicants to submit to the UIC Program Director extensive information on the characterization of surface and subsurface features of the proposed storage site, in particular on the injection zone(s), confining zone(s), and USDWs. Applicants will submit geologic and hydrogeologic data on the injection and confining zones, including their lithologic properties; the seismic history of the site; the structural geology of the site, including the presence of faults and fractures; and other information. Required submissions also include geochemical data on subsurface formations, including USDWs, and geomechanical data on the confining zone(s).

This section provides information to assist owners or operators in conducting the site characterization activities necessary to gather information, prepare, and submit a Class VI permit application. Each subsection below describes the activities owners or operators will need to perform to submit the elements of a Class VI permit application required at 40 CFR 146.82(a). For each required piece of information, this guidance describes potential sources of information and provides recommendations for how this information can be submitted to the UIC Program Director to support a determination that the site is suitable for GS. Note that, for completeness in describing a thorough geologic characterization, some of the information described in this section may only be available before construction if the site has been previously characterized for another purpose, e.g., for hydrocarbon exploration. Where this is not the case, such information will need to be finalized after the well is constructed or based on information gathered via a stratigraphic test well.

Where appropriate, the subsections below also provide recommendations and special considerations for obtaining and interpreting data and note particular aspects of the site characterization process that might warrant discussions with the UIC Program Director.

2.1. Regional Geology, Hydrogeology, and Local Structural Geology

Owners or operators must submit geologic and topographic maps and cross sections illustrating the regional geology and hydrogeology and the geologic structure of the local area [40 CFR 146.82(a)(3)(vi)]. This characterization will describe the area surrounding the proposed project including the subsurface formations that are targeted for injection and identified as the confining unit(s). This information may help in eliminating unsuitable project sites or identify the need to characterize additional confining zone(s). If data obtained during site characterization suggest that a secondary confining zone is needed to protect USDWs, the owner or operator is encouraged to communicate with the UIC Program Director about the need to characterize additional zones [40 CFR 146.83(b)]. See Section 3.6 for considerations related to secondary confinement.

Providing maps and cross sections of the region and local area will enable the UIC Program Director to place the project site in a regional geologic context, including the types of large-scale structural features that may act to confine a carbon dioxide plume. This information will also illustrate the relationship between the injection formation and regional and local USDWs. When considered along with detailed site-specific geologic information (see Section 2.3), this information will help in formulating the geologic conceptual model needed for modeling of the AoR.

Data Collection and Analysis

The geologic and topographic maps and cross sections to be submitted can be obtained through a number of sources such as the U.S. Geological Survey (USGS), state geological surveys, and other state and published literature and reports on general geology and water, mineral, and/or energy resources. For projects proposed in reservoirs undergoing enhanced oil recovery (EOR) or where significant exploration has taken place, owners or operators may have access to regional background information previously compiled.

Information to Submit

Owners or operators should demonstrate that an adequate screening-level analysis has taken place to determine if the project site is suitable. Maps, cross sections, and stratigraphic columns of the region and an accompanying narrative will constitute a key part of that demonstration. This information can provide the context for some of the specific information submitted to fulfill other requirements, e.g., descriptions of faults or geologic structure. It will also help in identifying the preliminary boundaries of the computational model used for delineating the AoR.

Features to describe in the narrative and in geologic and topographic maps and cross sections include:

- The names, lithologies, and depths of the injection formation(s) and confining zone(s);
- Depths, extent, and ground water flow patterns of regional USDWs;
- A brief synopsis of the geologic history of the project site;
- Regional faults, fault types, trends, and whether they transect the injection formation(s) and/or confining zone(s); and
- Structural geology of the local area:
    - Presence and trends of folds, and
    - Whether the proposed storage site will be bounded by faults or other structural features.

To support the UIC Program Director's evaluation of the submitted information, EPA recommends that, with the accompanying narrative, the owner or operator describe the regional setting and how the proposed project site fits into this regional setting. The owner or operator should ensure that the information submitted is complete, adequately describes the proposed project site and surrounding region, and is consistent with other available information about the region.

2.2. Map of Injection Well, Area of Review, Surface Water Bodies, Artificial Penetrations, and Faults

The Class VI Rule, at 40 CFR 146.82(a)(2), requires applicants for a Class VI permit to create a map to report the number or name and location of all wells in addition to a number of other surface features, water bodies, faults, and infrastructure. At 40 CFR 146.82(a)(4), the Class VI Rule also requires the tabulation of additional descriptive information regarding wells within the AoR that penetrate the injection or confining zone(s). Data compiled on wells within the AoR will help identify the need for corrective action. Furthermore, these data will help identify other activities (e.g., injection or production operations) that should be accounted for during AoR delineation and when developing the Testing and Monitoring Plan [40 CFR 146.90] and the Emergency and Remedial Response Plan [40 CFR 146.94].

At this stage of the site characterization process (particularly if the AoR delineation model has not been developed), estimates of the AoR may be preliminary, depending on the amount of pre-existing quality data, and refinements to the estimated AoR will be performed prior to operation once the formation testing program has been executed. Maps submitted at this initial stage should show at least the approximate AoR and the general direction of plume and pressure front migration. A detailed discussion of AoR delineation is provided in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*.

The Class VI Rule, at 40 CFR 146.82(a)(2), requires the map to show:

- **Surface bodies of water and springs.** This includes seasonal bodies of water such as vernal pools, fens, carrs, and playas;
- **Mines (both surface and subsurface) and quarries**. For subsurface mines, the UIC Program Director may request additional information such as the extent of subsurface mining and the maximum depth at which mining has occurred or, in the case of an active mine, is predicted to occur;
- **Surface features, including structures intended for human occupancy.** These include, but are not limited to homes, schools, hospitals, prisons, and other buildings. Other pertinent surface features include transportation infrastructure such as roads, highways, airports, and railways;
- Political boundaries such as **state, tribal, and territorial boundaries**. This information is needed to ensure that permitting follows all applicable laws and regulations within these jurisdictions and will inform notification of other UIC Program Directors, per 40 CFR 146.82(b);
- The surface trace of all **known and suspected faults.** The faults can be presented using standard geologic symbols indicating the relative motion of the fault blocks. Suspected faults must also be presented (suspected faults should be differentiated from known faults on the map). At the direction of the UIC Program Director or at their own discretion, the owner or operator may indicate the extent of complex fault zones through shading or some other means;
- **The number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells, dry holes, or deep stratigraphic holes.** This

information will help the UIC Program Director evaluate potential risks from artificial penetrations, especially any that penetrate the confining zone, to determine if risk is sufficient to render a site unsuitable, or to identify wells that are currently in use but might need to be plugged later; and

- **State- or EPA-approved subsurface cleanup sites.** Information should include any sites with the potential to impact USDWs.

The Class VI Rule, at 40 CFR 146.82(a)(4), requires tabulation of all wells within the AoR that penetrate the injection or confining zone(s). Such information must include:

- A description of each well's type, construction, date drilled, location, and depth;
- A record of plugging and/or completion; and
- Any additional information the UIC Program Director may require.

Data Collection and Analysis

Cartographic information for map features is available from a variety of sources:

- State geographic information system (GIS) clearinghouses. Most states offer online clearinghouses for state GIS data. This may include layers for boundaries, roads, buildings, and other information;
- National agencies such as the USGS, or local cartographic or planning offices. The USGS can also provide geologic maps containing the surface traces of faults; and
- Tax assessors, who may be able to provide boundary, building, and other map data.

For state- or EPA-approved subsurface cleanup sites, owners or operators may indicate the nature of the contamination at the site and the nature and progress of remediation activities at the site. In addition to the sources listed above, information on cleanup sites can be obtained from:

- National databases compiled by the EPA such as the Comprehensive Environmental Response, Compensation, and Liability Information System (CERCLIS) as part of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (Superfund) program;
- Various state departments (health, environment, natural resources, etc.) may also maintain their own databases of subsurface cleanup sites;
- Local universities and academic institutions; and
- Citizen watchdog groups.

The locations of wells in the proposed AoR and descriptive information on wells that intersect the injection or confining zone(s) can be obtained from:

- Federal agencies, such as EPA. The National UIC Data System and the Integrated Compliance Information System (ICIS) database may both provide well information;
- State agencies, such as state oil and gas commissions. These entities often maintain records of the location and construction parameters for all wells within the state;

- Geological surveys (both state and national). Maps may be available for either wells or magnetic anomalies, which may be used to infer the locations of wells;
- State GIS clearinghouses or city planning offices. These agencies may also provide layers or tables with well data;
- Water and other utilities. The UIC Program Director may request, and/or the owner or operator may provide, the yield of the water wells, the number of people supplied by the water wells, and the ownership status (public or private) of water wells; and
- Academic literature. This is especially applicable for stratigraphic boreholes.

Only existing information in the public record is required to be used when populating the map required at 40 CFR 146.82(a)(2). However, additional data requested at 40 CFR 146.82(a)(4) on well parameters for wells within the AoR may need to be generated by the owner or operator if it is not available or reliable. In cases where available records do not provide the necessary information required at 40 CFR 146.82(a)(4), or indicate that a well was plugged improperly or with materials inappropriate for contact with carbon dioxide, then site investigations are required to be performed to establish the condition of the well, as discussed at 40 CFR 146.84(c)(3).

Information to Submit

The owner or operator must submit a map that identifies all of the required information described above [40 CFR 146.82(a)(2)]. When data are not sufficiently complete to locate wells with certainty, and if appropriate or requested by the UIC Program Director, the owner or operator may mark regions of the map that are known or suspected of being well fields. For these areas, a description of typical well construction and operation (e.g., injection, production) may be included with the description of known wells within the AoR. This approach may be needed in areas with an extensive history of hydrocarbon production or areas suspected to have a number of private water wells.

Additional information that may be included or requested by the UIC Program Director includes gas storage fields, other injection operations, local, state, and national park or monument boundaries, locations of archeological or cultural heritage sites, military installations, habitat for threatened or endangered species, surface water impoundments, and floodplain or spillway boundaries. The applicant is encouraged to include on the map any additional information they deem appropriate.

The UIC Program Director may request additional information if full coverage of the AoR is not provided. The owner or operator should also provide sufficient information to support the UIC Program Director's review of existing features that may affect water quality in USDWs and that may affect baseline environmental conditions in the AoR.

2.3. Detailed Geology and Hydrogeologic Site Characterization

This section provides guidance on characterizing the specific geologic, hydrogeologic, geochemical, geophysical, and geomechanical properties of the proposed site. The site characterization activities described in the subsections below outline the information and data that must be considered by the UIC Program Director in authorizing a Class VI well permit as identified in 40 CFR 146.82(a)(3)–(6).

2.3.1. Maps and Cross Sections of the Area of Review

Maps and cross sections of the AoR are required by the Class VI Rule at 40 CFR 146.82(a)(3)(i). The maps will likely include both topographic and geologic maps. Geologic maps in particular, and accompanying cross sections and stratigraphic columns, summarize key information on lithology, sequence of geologic units (including the proposed injection formations, confining units, and USDWs), approximate formation thicknesses, lateral extent of units, and correlation of units in the vicinity of the proposed project site and across the region. This information will help the UIC Program Director understand the spatial relationship between the proposed injection formation and other aspects of the site geology, including USDWs. The information will also help inform the geologic conceptual model on which the modeling for the AoR delineation is built. This information can also help identify zones for geochemical monitoring.

The narrative accompanying the maps and cross sections of the AoR should be similar in scope to the evaluation of regional geology, but provide more detail on the AoR. Among other features, the owner or operator should highlight the lateral extent of the proposed injection formation and show that it is continuous throughout the proposed site [40 CFR 146.82(a)(3)(iii) and 146.83(a)(1)]. The required evaluation of the areal extent of the confining zones is equally critical [40 CFR 146.82(a)(3)(iii) and 146.83(a)(2)]. If there are additional confining units farther up in the stratigraphic column, this strengthens the case for suitability of a proposed site. Areas where formations pinch out should be identified. An estimate of the approximate dimensions of the injection formation in the AoR also allows the owner or operator to estimate storage capacity.

Data Collection and Analysis

If a project site has been well characterized for hydrocarbon exploration and/or production, geologic maps and cross sections and topographic maps of the area may be available. Topographic and geologic maps may be obtained from the USGS, state geologic surveys, or through a commercial provider. Geologic maps and cross sections may also be produced by the owner or operator based on information from cores, well logs, field mapping, or seismic surveys. Maps and cross sections should be of an appropriate scale to illustrate features at the project site that would affect the suitability of the site for GS.

Geologic maps, cross sections, and stratigraphic columns may be improved with additional data. As site characterization progresses, it is recommended that the owner or operator be alert to potential alternative interpretations of the cross sections and other similar map information. Owners or operators should discuss any assumptions or uncertainties in the features illustrated in maps and cross sections. If an injection depth waiver is sought, the owner or operator should make sure that the cross sections include all relevant layers down to at least the first USDW below the lower confining zone.

Information to Submit

EPA recommends that owners or operators include a narrative with the maps and cross sections that describes, at a minimum:

- The formation names, lithologies, and depths of the injection formation(s), confining zone(s), and USDWs within the proposed AoR;
- A general description of stratigraphy, including the vertical distance and formations separating the injection formation from USDWs; and
- Structural geology of the project site, including whether the proposed storage site will be bounded or influenced by a structural trap (e.g., faults or a dome).

Identification and analysis of faults and their potential to affect containment is required at 40 CFR 146.82(a)(3)(ii) and is discussed in Section 2.3.2. Information on facies changes is required at 40 CFR 146.82(a)(3)(iii) and is discussed in Section 3.1.

2.3.2. Faults and Fractures in the Area of Review

The Class VI Rule, at 40 CFR 146.82(a)(3)(ii), requires owners or operators to submit information on the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AoR and a determination that they would not interfere with containment. This information is needed to demonstrate to the UIC Program Director that the site has a confining zone(s) free of transmissive faults or fractures and that will allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s), as required at 40 CFR 146.83(a)(2). Evaluation of fault stability and fault or fracture sealing capacity is needed to demonstrate that faults will not interfere with containment of the carbon dioxide. If an injection depth waiver is sought, the owner or operator must also demonstrate that the lower confining unit(s) is/are free of transmissive faults and fractures [40 CFR 146.95(a)(2)].

EPA recommends that owners or operators obtain information on faults in the injection formation as well. This information should also include whether a fault zone consists of one major plane or a series of faults that may collectively provide a conduit for fluid movement through the confining zone, especially if the faults intersect lenses of high permeability material. Faults crossing the confining zone will need to be evaluated for their stability (see below) and sealing capacity (see Section 3.5 and the Appendix).

Data Collection and Analysis

Materials available from the USGS include geologic and topographic maps (e.g., the National Geologic Map Database), aerial photographs, and reports. The USGS's Earthquake Hazards Program provides maps of faults for many regions in the United States. The Earthquake Hazards Program database (available at http://geohazards.cr.usgs.gov/cfusion/qfault/index.cfm) provides detailed information on faults. Maps and other data may also be available from state geologic surveys. Such maps (i.e., from the USGS and state geological surveys) are generally at the quadrangle scale, but maps can also be found at the county and state scale.

Geophysical survey data, including seismic, electrical, magnetic, and gravity surveys, can complement information from maps and other sources and can be used to delineate faults and fractures and to characterize their geometry. The project area and the size and location of the fault will determine whether two dimensional (2D) data will provide sufficient information or whether the higher resolution of three dimensional (3D) data is needed. See Section 2.3.10 and the Appendix for additional information on geophysical surveys.

Fault Stability and Fault or Fracture Sealing Properties

Assessment of fault stability requires knowledge of fault geometry, which can be obtained from the structural interpretation of seismic data, as well as in situ stresses (see Section 2.3.6). Several options are available to support a determination that faults will not interfere with containment through reactivation, including assessments of failure plots, 3D fault slip tendency, and critical pore fluid pressure increase (see the Appendix for additional details). EPA recommends that owners or operators use one of the above methods, based on information on downhole stresses and fault geometry, to determine fault stability and the maximum sustainable pressure that could be associated with injection. This information can be used to set safe injection pressure limits.

Faults and fractures can be assessed for the likelihood that they are sealing using one of several approaches described in Section 3.5.2. Faults may be assessed for the units they juxtapose, the presence of catalysis, the shale gouge ratio, or pressure compartmentalization. Both faults and fractures may be assessed for whether mineralization has rendered them non-transmissive. The choice of method will depend upon the availability of data and samples.

Information to Submit

In describing faults and fractures, EPA recommends that owners or operators submit the following information:

- Location and characteristics of the fault or fracture (e.g., geometry, depth, fault displacement, units juxtaposed by fault);
- Formations intersected or transected by the fault or fracture;
- Methods and results of fault stability analyses and comparison to preliminary anticipated (modeled) pressures during the injection phase of the project; and
- Information on faults and fractures in the lower confining zone (in cases where an injection depth waiver is sought).

To demonstrate that a fault is not transmissive, the owner or operator may submit:

- A description of the approach used to infer whether a fault or fracture is transmissive;
- A summary table of data used to formulate the estimate;
- Supporting data and information (e.g., analyses of core samples, results of geophysical surveys, pore pressure data, maps, and cross sections) and any relevant calculations (e.g., calculation of shale gouge ratio);

- A narrative that describes and integrates the relevant information, including a discussion of any spatial heterogeneity in sealing properties and whether a fault or fracture is likely to be transmissive in the project area; and
- A discussion of uncertainties in the data.

See Section 3.5.2 and the Appendix for examples of approaches that may be employed for this demonstration.

To support the UIC Program Director's evaluation of the data, the owner or operator should make sure that the data are complete and adequate for understanding the geometry of any major faults and the pressures that could lead to activation. All supporting data should be provided and/or referenced in the appropriate section of the permit application.

2.3.3. Depth, Areal Extent, and Thickness of the Injection and Confining Zones

The Class VI Rule requires the owner or operator to provide information to the UIC Program Director on the depth, areal extent, and thickness of the injection formation and confining zone(s) [40 CFR 146.82(a)(3)(iii)]. These features affect the ability of the injection formation to receive and store the injectate, as well as the ability of the confining zone(s) to contain the carbon dioxide and pressure front. In addition, the depth of the injection zone will govern the state (e.g., supercritical) of the injected carbon dioxide.

Information on the lithologies and thicknesses of both the injection and confining zones will support the estimation of storage capacity and development of a site-specific geologic conceptual model and the computational modeling required for AoR determinations at 40 CFR 146.84. (See the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for more information on multiphase fluid modeling for AoR determinations). It will also support an analysis of facies changes, as required at 40 CFR 146.82(a)(3); see Section 3.1 for information on conducting facies analyses.

Data Collection and Analysis

Seismic techniques and other geophysical methods can provide valuable stratigraphic information on the injection and confining zones. Ideally, demonstration of the extent of these formations will be documented by adequate boreholes and grids of 2D or 3D seismic images in addition to maps and cross sections (Chadwick et al., 2008). More information on the details of geophysical techniques and a brief description of seismic stratigraphy can be found in Section 2.3.10 and in the Appendix. Seismic techniques are also discussed in the *UIC Program Class VI Well Testing and Monitoring Guidance*. If the owner or operator is applying for an injection depth waiver, information on depth, extent, and thickness of the lower confining zone(s) must be supplied as well, as required at 40 CFR 146.95 (see the *UIC Program Class VI Well Injection Depth Waivers Guidance* for further discussion).

Information to Submit

EPA recommends that owners or operators discuss the depth, areal extent, and thickness of the injection formation and confining zone(s) in a narrative discussion that accompanies the geologic maps and cross sections required at 40 CFR 146.82(a)(3)(i); see Section 2.3.1. The narrative should include a discussion of data quality and uncertainties in the information. If an injection depth waiver is sought, the owner or operator should provide similar types of information on the lower confining zone(s) as well.

Formation thickness may also be illustrated using:

- Isopach maps (contour maps showing equal values of true stratigraphic thickness); and
- Isochore maps (contour maps showing equal values of true vertical thickness) and supported by available well logs and cores (also see Sections 4.1 and 4.2).

Other supporting information may include:

- Seismic or other geophysical survey results, with relevant information highlighted (if geophysical data are used for this demonstration); and
- Well log data (when it is available), with injection and confining zones highlighted (if well logs are used for this demonstration).

Any variability in the thickness of the injection formation and confining zone(s) that could affect storage of the carbon dioxide should be discussed in the narrative report, and the owner or operator should demonstrate that this would not adversely affect confinement. The owner or operator should bear in mind that if the areal coverage of the confining zone does not cover the full extent of the AoR or appears to be discontinuous, the UIC Program Director may request information on a secondary confining zone.

2.3.4. Petrology and Mineralogy of the Injection and Confining Zones

The Class VI Rule requires the owner or operator of a proposed Class VI injection well to submit data on the mineralogy of the injection and confining zone(s) [40 CFR 146.82(a)(3)(iii)]. This information will support the identification of any geochemical reactions that may affect the storage and containment of injected carbon dioxide which could result from potential changes in the properties of the injection or confining zones (e.g., porosity, permeability, injectivity). It will also provide information on mobilization of trace elements from the formation matrix if minerals known to contain trace elements are identified, which informs decisions regarding parameters to analyze as part of a testing and monitoring program. Evaluation of the minerals and potential geochemical reactions is the basis of the required demonstration of compatibility of the carbon dioxide stream with fluids in the injection zone and minerals in the injection and confining zones required prior to commencement of injection at 40 CFR 146.82(c)(3); see Section 3.3. This information may also support the facies analysis required at 40 CFR 146.82(a)(3)(iii) (see Section 3.1).

If an evaluation of potential geochemical processes suggests that long-term storage and confinement of carbon dioxide may be affected by changes in the injection formation and confining zone(s), the AoR delineation may need to account for geochemical reactions through the use of reactive transport models. Any potential effects on storage and confinement due to mechanisms such as precipitation and dissolution may also affect the post-injection site care (PISC) time frame. [40 CFR 146.93(c)(1)(v)].

Data Collection and Analysis

If the proposed site has undergone previous characterization (e.g., for oil and gas development), data on the mineralogy of the injection and confining zones may be available. Owners or operators should consult with the UIC Program Director regarding whether available data are of sufficient quality and completeness and whether they adequately represent the injection formation and confining zones in the AoR, or if additional information is needed. If the UIC Program Director determines that additional data are needed to satisfy the requirements at 40 CFR 146.82(a)(3)(iii), this may entail analysis of existing cores or, if needed, the collection of new cores.

Collection of new data will most likely be necessary in pristine saline formations under consideration for GS project sites; however, such new information may also be needed for depleted oil and gas reservoirs if the previous characterization was not sufficient to demonstrate that the site meets the requirements of the Class VI Rule. If the owner or operator is requesting an injection depth waiver, the lower confining zone must be represented in this analysis [40 CFR 146.95(a)(2)]; see the *UIC Program Class VI Well Injection Depth Waivers Guidance* for further discussion of injection depth waivers. EPA recommends that owners or operators discuss with the UIC Program Director any potential needs for stratigraphic/test wells to collect the necessary data and samples.

Basic lithologic information can be obtained from inspection of cuttings and cores retrieved during drilling of a stratigraphic well (or from existing samples from previous work at the project site). Such information may be reported as part of routine mud logging. Polarized light microscopy and scanning electron microscopy may be used on thin sections, and powdered samples may be subject to X-ray diffraction (XRD). Background information on these methods is provided in the Appendix.

Information to Submit

EPA recommends that owners or operators submit a narrative report that includes, at a minimum, the following information:

- Methods used in examining samples;
- Locations (on maps) and depths of samples and the names of the formations sampled;
- Lithologies and descriptions (e.g., color, texture) from cores or hand samples;
- Mineralogic and petrologic descriptions obtained via microscopy (with approximate percentages of minerals);
- Cementation minerals and dissolution features; and

- A preliminary discussion of geochemical reactions that may affect the storage, confinement, and/or overall performance of the project (see Section 2.3.9 for additional information on baseline geochemistry).

Although the identification of mineralogy is required at 40 CFR 146.82(a)(3)(iii), and must be submitted before a permit is obtained to construct the injection well, additional data will also be obtained during the core analyses performed pursuant to 40 CFR 146.87(b), and the owner or operator must provide any updates to the UIC Program Director before injection is authorized, per 40 CFR 146.82(c)(2).

To support the UIC Program Director's evaluation of the application, the owner or operator should demonstrate that a sufficient number of samples have been analyzed to provide an indication of variability in mineralogy. The owner or operator should also highlight any information on the mineralogy and petrology of the injection and confining zones that is relevant to the required analysis of compatibility of the carbon dioxide to subsurface formations (see Section 3.3).

Lithologic and mineralogic information should be complete and consistent with other information sources such as maps and well logs. The UIC Program Director may ask for additional information if descriptions and analyses are incomplete.

2.3.5. Porosity, Permeability, and Capillary Pressure of the Injection and Confining Zones

Data on porosity, permeability, and capillary pressure of the injection and confining zones, required at 40 CFR 146.82(a)(3)(iii), are crucial for a number of aspects of site characterization including determination of storage capacity, injectivity, and integrity of the confining zone. They are also needed for the multiphase modeling to predict plume and pressure front behavior and delineate the AoR. Data may be obtained from well logs and laboratory analyses of core samples. If the owner or operator is seeking an injection depth waiver, information on the lower injection and confining zones is needed to evaluate their suitability.

Section 2.3.5.1 describes information sources and analyses and information to submit to the UIC Program Director related to porosity; Section 2.3.5.2 addresses permeability data; and Section 2.3.5.3 discusses data on capillary pressure.

2.3.5.1. Porosity

Evaluation of porosity may entail collection and review of existing data, use of field methods, and use of laboratory methods, as described below.

Data Collection and Analysis

Existing Data

In evaluating existing data from prior activities in the project area, owners or operators should note the methods used, the locations where samples were taken, and the overall quality of the data. Sufficient representative data will be needed from within the AoR. If available data are inadequate to establish the suitability of the site, the owner or operator will need to collect new data or perform new analyses. Any questions about the suitability and representativeness of samples should be discussed with the UIC Program Director.

Field and Laboratory Methods

If existing data are not available, are inadequate, or are of insufficient quality, new data will be needed. To satisfy the requirement under 40 CFR 146.82(a)(3)(iii), the owner or operator may use laboratory or field methods (e.g., well logging, seismic) to measure and/or estimate the porosity of the injection and confining formations. See Section 2.3.10 for additional information on seismic surveys. See the Appendix for additional information on the principles of well logging for porosity and brief descriptions of laboratory methods. When considering field data, owners or operators should be aware of the limitations and appropriate applications of different methods. Supporting data on lithology, corrections and/or interpretations applied to well logs or geophysical methods, and any statistical computations performed should be described and referenced.

In selecting samples for laboratory analysis, EPA recommends that owners or operators be aware of the quality of the sample because the method of sample collection can influence the measured porosity. Owners or operators should also note any possible issues with sample quality when reporting results.

Comparing Laboratory and Field Data

Laboratory and field methods may or may not agree because laboratory methods provide point measurements, while field methods sample a volume of the subsurface. As a result, field-based data can incorporate small-scale heterogeneities that result from variability in lithologic characteristics and larger-scale fluid migration pathways such as vugs, fractures, and dissolution features (Cone and Kersey, 1992). Therefore, field measurements may yield higher or lower values for a particular formation than measurements collected in the laboratory. EPA suggests that owners or operators address any discrepancies between field and laboratory data if both types of data are submitted.

Information to Submit

EPA recommends that owners or operators submit, at a minimum, the following information on porosity:

For laboratory-based data:

- Locations (on maps) and depths of cores and the formations from which those cores were taken;
- Coring method used and notes on the condition of the cores;
- Laboratory analysis method(s) used, justification for selection of method(s), associated assumptions, and a description of experimental conditions;
- Approximate grain sizes and shapes;
- Approximate pore sizes and shapes;
- Results in tabular and graphical form shown as laboratory results and porosity distributions within the injection and confining formations; and
- Photomicrographs if porosity was determined using thin sections.

For field-based data:

- Results of field measurements and estimations shown as porosity distributions within the injection and confining formations (also see Section 4.1), including:
  - Date and time of sampling/surveying,
  - Method used (e.g., logging, seismic),
  - Information on the location/area and intervals tested, and
- Calculations, corrections, or other steps in processing of field data.

For both field- and laboratory-based data:

- Summary statistics on data and any statistical representations (e.g., variograms); and
- A discussion of the results, including data quality and sources of uncertainty.

Because core samples represent point measurements, for reliable results, measurements are best made on a number of cores. The applicant should consider submitting a statistical representation of measurements such as a variogram (see the Appendix for additional information).

EPA recommends that the owner or operator demonstrate that the data are of sufficient quality. The owner or operator should ensure that a sufficient number of samples were analyzed and that they represent likely heterogeneities in the injection and confining zones. The owner or operator should demonstrate to the UIC Program Director that appropriate methods were used and that downhole conditions were simulated (or explain why they were not and whether this is expected to affect the usability of the measurements). Finally, EPA recommends that owners or operators provide a discussion comparing field and laboratory-based data, giving careful consideration to the reliability of the measurements and contributions to any discrepancies.

2.3.5.2. Permeability

The permeability of the injection zone is one of the factors governing the rate at which carbon dioxide can be injected and is one of the parameters needed for the computational modeling involved in AoR determination. Permeability of the confining zone is one of the factors considered in assessing the suitability of the confining zone. The subsections below provide considerations for the procurement and submission of permeability data. Because a GS project is a multiphase fluid system, effective and relative permeability data are also needed for AoR determination.

<u>Data Collection and Analysis</u>

EPA encourages owners or operators to use data from field testing, well logging, and laboratory analyses of cores to estimate intrinsic (absolute) permeability. Laboratory analyses should also be performed to obtain a relative permeability-saturation function. When comparing field and laboratory measurements for intrinsic permeability, owners or operators should bear in mind that permeability measurements can differ by scale. Well tests measure a much greater area than core samples. As such, well testing tends to provide composite representations of localized variability. Permeability derived from well logs represents an intermediate scale between core logs and well tests.

Existing Data

Where data are available from prior activities in the project area, owners or operators should take note of methods used, locations from where samples were taken, and overall quality of the data. These are described below, along with a discussion of spatial variability in permeability data.

Field Methods for Absolute Permeability

Permeability can be estimated in situ using a variety of methods. Pressure changes during fall-off tests can be analyzed quantitatively. If multiple wells are available, variable flow test analysis can be used to determine permeability provided that the reservoir pressure, flowing bottomhole pressure, flow rates, and the total time of the test are known (Smolen, 1992; Matthews and Russell, 1967). Permeability can also be determined from well log data using an estimator of porosity such as a density log. A summary and comparison of the various empirical methods available to relate porosity, resistivity, and other parameters to permeability is given by Balan et al. (1995). Nelson and Batzle (2006) also provide a description of methods for permeability estimation from well logs. Owners or operators should be aware of the limitations associated with any method they select and be alert for uncertainties in the data and how these uncertainties might affect modeling efforts.

Laboratory Methods

As with porosity measurements, owners or operators should be aware of any damage to cores that may have occurred during drilling and that might reduce permeability. Plug samples taken from the center of the core may be the best way to avoid such damage or infiltration of mud or other particles into the pore spaces. See the Appendix for additional discussion regarding coring and sample selection for permeability measurements.

EPA recommends that owners or operators consider conducting laboratory measurements of absolute permeability in an environment that simulates reservoir conditions or discuss anticipated effects that pressure and temperature might have on results. When permeability is measured from a whole core, measurements should be reported in two directions: one parallel to the major fracture plane and the other at 90 degrees perpendicular to this direction (Almon, 1992).

A relative permeability-saturation function is needed for incorporation into the computational modeling for the AoR delineation. For GS projects, changes in relative permeability may result in improved or reduced injectivity into reservoir rocks and/or improved or reduced sealing capacity for confining formations. In measuring and reporting data on relative permeability, owners or operators should be aware of hysteresis effects and should consider the need for separate curves for drainage and imbibition. Additional discussion of permeability-saturation functions is provided in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*.

EPA recommends that data be obtained from analysis of samples collected from as many cores, boreholes, or wells as practical and available to provide an understanding of spatial variability in permeability. Along each borehole, a number of core samples should be analyzed to capture heterogeneity. Owners or operators should be alert to variations that might indicate lenses of lower or higher permeability material that may affect storage capacity or carbon dioxide migration. Furthermore, permeability may be an anisotropic property that varies in the x, y, and z directions and typically shows the greatest variation in the direction perpendicular to layering. For the computational modeling performed for AoR determination, a realistic representation of the permeability distribution is needed, and EPA suggests that owners or operators consider a geostatistical approach. Further discussion regarding geostatistical approaches is provided in the Appendix and also discussed in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance.*

Information to Submit

EPA recommends that owners or operators submit the following data related to permeability of the injection and confining zones:

For laboratory-based data:

- Locations (on maps) and depths of cores and the formations from which cores were taken;
- Coring method used, and notes on the condition of the cores;
- Approximate grain sizes and shapes;
- Approximate pore sizes and shapes;
- Laboratory analysis method(s) used, justification for selection of method(s), associated assumptions, and a description of experimental conditions; and
- Results in tabular and graphical form shown as laboratory results and permeability distributions in the injection and confining formations.

For field-based data:

- Date, time, and method of logging/surveying;
- Information on the locations (on maps)/areas and intervals tested;
- Calculations, corrections, or other steps used in processing of field data;
- Methods used for permeability estimation (e.g., specific well logs, seismic) or whether new interpretations are being made using archived data; and
- Results of field measurements and estimations shown as permeability distributions within the injection and confining formations.

For both field- and laboratory-based data:

- Summary statistics on data and any statistical representations (e.g., variograms); and
- A discussion of the results, including data quality and sources of uncertainty.

To support the UIC Program Director's evaluation, the owner or operator should demonstrate that the data are complete and representative of the actual site. The discussion of permeability should also address variability in permeability and implications for the operational parameters for the project or for the storage capacity of the injection formation. See the Appendix regarding geostatistical methods.

2.3.5.3. Capillary Pressure

Capillary pressure is one of the factors affecting the integrity of the confining zone and how readily carbon dioxide will penetrate into the confining zone.

<u>Data Collection and Analysis</u>

Several established methods are available for measurement of capillary pressure: mercury injection, centrifuge, porous plate, and restored state cell. See the Appendix for brief descriptions of these methods. In selecting a suitable method, owners or operators should consider methods that allow measurement at pressures and temperatures representative of the injection zone. Particular attention should be paid to the capillary pressure of the confining zone because a sufficiently high capillary pressure is one of the mechanisms by which the confining zone acts to inhibit migration of carbon dioxide. Owners or operators may compare their estimated capillary entry pressure (Pe) to the anticipated surface tension of the supercritical carbon dioxide (Chadwick et al., 2008), taking into account the anticipated buoyant pressure and potential height of the carbon dioxide column (Lindeberg, 1997).

<u>Information to Submit</u>

EPA recommends that owners or operators submit the following information on capillary pressures of the injection and confining zones:

- Locations (on maps), formations, and depths of samples used for analysis;

- Method used for analysis, fluid used, and laboratory conditions;
- Results in functional forms for the saturation-capillary pressure functions and/or tabular and graphical form;
- Summary statistics on data;
- A discussion of any limitations of the data or methods; and
- Any issues associated with extrapolation of results to a setting in which supercritical carbon dioxide is the non-wetting fluid.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that the data are of sufficient quality and that the number and locations of samples are adequate to provide good characterization of the injection and confining zones.

2.3.6. Geomechanical Characterization

The Class VI Rule requires that geomechanical information be submitted on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone [40 CFR 146.82(a)(3)(iv)]. Geomechanical characterization is important for evaluating confining zone integrity as well as setting safe operational parameters. If an injection depth waiver is sought, the owner or operator must also characterize and provide information on the lower confining zone(s) as required at 40 CFR 146.95(a)(2); this would include geomechanical information to support a complete analysis.

Data Collection and Analysis

This section outlines options for performing and submitting the results of geomechanical studies of fractures, ductility, rock strength and stresses, and pore pressure measurement.

Fractures may be detected in boreholes by several methods, including fracture finder (microseismogram) logs, caliper logs, or acoustic logs. Also, resistivity, gamma, and neutron logs can detect clay or fluids contained in fractures. Video logs can also show fractures. Fractures may be seen in cores, although unless the core was oriented, it will not be possible to determine the orientation of the fractures.

Ductility is most commonly measured by performing a triaxial load test on a core sample. EPA recommends that such measurements be conducted in conjunction with other tests of core samples, such as strength, porosity, permeability, and capillary pressure.

Rock strength can be measured in the laboratory using a triaxial compression test. ASTM International (ASTM) D7012-10, *Standard Test Method for Compressive Strength and Elastic Moduli of Intact Rock Core Specimens under Varying States of Stress and Temperatures* (ASTM, 2010), is suitable for simulating downhole stress conditions. Owners or operators should bear in mind that these measurements will not account for larger scale features that affect overall strength in situ, such as faults or joints; results should be interpreted accordingly.

The in situ stress field is important in determining the natural stresses in the formation and, therefore, the reaction of the various geologic units to injection, including the potential for fault reactivation (as discussed in Section 2.3.2). The in situ stress field consists of three components: vertical stress, maximum horizontal stress, and minimum horizontal stress:

- **Vertical stress** can be determined by integrating the density of the rock above the point of stress measurement (Chiaramonte et al., 2008; Herring, 1992; Streit et al., 2005). The density is determined using density logs (see the Appendix); and
- The magnitudes of the **minimum horizontal stress** (S_{hmin}) and **maximum horizontal stress** (S_{hmax}) can be determined with considerable accuracy through direct in situ formation stress tests (See Zoback et al., 2003). ASTM Method D 4645-08, *Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method* (ASTM, 2008) may be used. Additional descriptions of the determination of in situ stresses at a GS site are given by Chiaramonte et al. (2008), Streit et al. (2005), and Streit and Hillis (2004).

Pore pressure can be measured in an open borehole by formation testers, either on wireline (Smolen, 1992) or during logging while drilling (LWD). If existing data are not available, this information will likely be acquired as part of logging and testing procedures after the well is constructed or by drilling a stratigraphic test well to obtain the necessary data to meet the requirements at 40 CFR 146.82(a).

<u>Information to Submit</u>

In submitting field- or laboratory-based information on geomechanical properties, the owner or operator should provide:

- The test(s) performed, dates, and locations (on maps);
- Sample collection procedures for cores;
- Test conditions (as appropriate);
- Results in tabular and/or graphical form;
- A narrative of results, including any anomalies or uncertainties in the data;
- Comparison of data from different tests if more than one type of test is used for a particular parameter; and
- Any issues with sample procurement, e.g., disintegration of poor quality rocks during transport or sample retrieval, the existence of discontinuities (fractures, fossils, etc.) in tested samples.

To support the UIC Program Director's evaluation of the geomechanical data submitted, EPA recommends that the owner or operator demonstrate that the data are complete, and that all data (e.g., from different surveys and logs) support consistent conclusions. The owner or operator should also demonstrate that in situ stress fields are consistent with and support the appropriateness of the proposed injection pressures and that fault stability analyses are consistent with in situ stress data (see Section 2.3.2 for additional information on fault stability analyses).

2.3.7. Seismic History

The Class VI Rule, at 40 CFR 146.82(a)(3)(v), requires Class VI permit applicants to report on the seismic history of the project site, including the presence and depth of all seismic sources. Additionally, the Rule requires a determination that seismic activity will not compromise subsurface containment of injected carbon dioxide. Records of prior seismic activity (both historical and geologic) should be used to make a determination of seismic risk. Information submitted for this requirement will also help to establish a site-specific monitoring program and inform the Emergency and Remedial Response Plan required at 40 CFR 146.94.

EPA anticipates that existing data will be sufficient for determining the presence and depths of all seismic sources. However, owners or operators may need to model or otherwise determine, using documented methods, that seismic activity from identified sources will not endanger USDWs.

Data Collection and Analysis

Seismic records and confirmed or inferred seismic sources are available from a variety of national and state sources, many of which are free and publicly available. State databases are generally more detailed, but sometimes contain partial or incomplete records. Nationally, the USGS Earthquake database provides source, date, time, latitude, longitude, magnitude, intensity, and seismic-related information for earthquakes greater than magnitude (M) 2.5. For earthquakes greater than M 0, the Advanced National Seismic System catalog, hosted by the Northern California Earthquake Data Center, is available. Other national databases include the Center for Earthquake Research and Information (CERI) and the National Oceanic and Atmospheric Administration (NOAA)'s National Geophysical Data Center. The USGS's Earthquake Hazards Program database (available at http://geohazards.cr.usgs.gov/cfusion/qfault/index.cfm) also provides information on recorded earthquakes.

Databases cataloging active faults are also available. These databases provide information on the hypocenters of seismic events, which can be mapped to provide a record of seismic sources for an area. Other databases of seismic sources include the USGS's Quaternary Fault and Fold Database of the United States, which tracks faults associated with seismic events greater than M6. Property insurers may also be able to provide seismic data for the region surrounding the proposed site.

Information on earthquake risk is available, most notably from the USGS's National Seismic Hazards Maps, which are available at numerous scales and for numerous risk thresholds. The data and software used to create the maps are also freely available, enabling the customization of maps and introduction of new data or modeling parameters. International and national humanitarian organizations, engineering organizations, and disaster preparedness agencies have also developed manuals, plans, and models of earthquake risk and, in addition, have attempted to quantify the potential impact of seismic events on infrastructure. For example, the Federal Emergency Management Agency (FEMA) has several manuals on seismic risk throughout the United States. The internationally-developed Global Earthquake Model (GEM) may also provide useful information for determining the seismic risk to infrastructure at various scales.

Although a seismic event would not necessarily lead to loss of containment, using seismic hazard maps to demonstrate the reasonable expectation that no seismic events would occur during the course of a GS project may fulfill the requirements at 40 CFR 146.82(a)(3)(v). However, if such maps indicate a substantial likelihood of seismic activity, other required geologic information, such as geomechanical data, depth to confining zones, and fault stability analysis may be needed to demonstrate that seismic activity will not compromise subsurface containment. Any demonstration that seismic activity will not interfere with containment should support a demonstration that the confining zone(s) will not be compromised by generation of new faults or reactivation of existing faults and that well bores will not be damaged in order for the site to meet the requirements at 40 CFR 146.83. The owner or operator should also consider the effect that seismic activity would have on site access and the ability of the owner or operator to verify containment under those circumstances as discussed in the Emergency and Remedial Response Plan.

<u>Information to Submit</u>

In reporting information on seismic risk, owners or operators should submit the following:

- A tabulation and/or map of seismic sources and their depths;
- A tabulation of seismic events, their hypocenters, and magnitudes for as far back as data are available;
- The sources of all seismic history data;
- Information on any seismic risk models used and the results; and
- A discussion of the degree of seismic risk in the region and information to support a determination that the confining system and wells at the project site are not vulnerable to damage from seismic activity.

The owner or operator should demonstrate to the UIC Program Director that the data provided to support an evaluation of seismic risk cover an appropriate time period and include sufficient information on the magnitudes and locations of the hypocenters of previous seismic events. If seismic risk models are used, the owner or operator should describe any limitations of those models.

2.3.8. Hydrology and Hydrogeology of the Area of Review

The owner or operator of a proposed Class VI injection well must submit maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells, and springs within the AoR, their positions relative to the injection zone(s) and confining zone(s), and the direction of water movement, where known [40 CFR 146.82(a)(5)]. This information can demonstrate the relationship between the proposed injection formation and any USDWs, and it will support an understanding of the water resources near the proposed well. The maps and cross sections developed to meet this requirement may be related to or overlain on the maps and cross sections illustrating regional geology and hydrogeology required at 40 CFR 146.82(a)(3)(vi); see Section 2.1. Potentiometric maps and isopach maps may also be submitted; additionally, the cross sections submitted to satisfy the requirements at 40 CFR 146.82(a)(3)(i) should include information on the vertical limits of USDWs in the AoR.

This information can support development of the water quality monitoring procedures in the Testing and Monitoring Plan required at 40 CFR 146.90.

<u>Data Collection and Analysis</u>

In most cases, the information needed to satisfy this requirement will be available from existing data sources, as described below. However, the owner or operator should discuss the available information with the UIC Program Director to ensure that the level of detail and the areal scope over which the information is available will be adequate to demonstrate that all USDWs have been identified, accounted for, and characterized.

Information on **USDWs and springs in the AoR** can be obtained from the USGS as well as from state and local agencies (e.g., departments of environmental protection or municipalities). Published academic literature and reports from existing exploration or injection projects may also be used. In particular, the USGS maintains a website for ground water information that includes ground water use, aquifers, and water quality data (http://water.usgs.gov/ogw/data.html). Additionally, the USGS's Hydrologic Investigations Atlas Series contains maps with a large amount of water resources information including water availability, producing aquifers, depth to ground water, and other data. More than 700 of these atlases have been published and are available at http://pubs.usgs.gov/ha/ha730.

If the project involves an injection depth waiver, the owner or operator will need to provide information on USDWs *above and below* the injection zone. Information on all USDWs—above and below the injection zone—should be provided in the Class VI permit application *and* the injection depth waiver application required at 40 CFR 146.95(a) to support a review of all USDWs in the context of each evaluation. See the *UIC Program Class VI Well Injection Depth Waivers Guidance* for additional information on the injection depth waiver application.

Information on **water wells in the AoR** is available from the following sources:

- State water centers or water surveys, state departments of water resources, or state Water Resources Research Institutes;
- State health departments, which may have information on local and regional water supplies and private wells and state engineer's offices may have databases of well permits; and
- State well permitting records, which may provide locations of public and private supply wells. States that issue well permits typically keep permit information in a searchable database either online (e.g., on environmental protection websites), or in hardcopy at an office or agency library.

This information will complement the information submitted to satisfy the requirement for a tabulation of all wells within the AoR that penetrate the injection or confining zone(s) at 40 CFR 146.82(a)(4). Note that the requirement discussed in this section, at 40 CFR 146.82(a)(5), is to show the location of all water wells, whereas 40 CFR 146.82(a)(4) is specific to wells that penetrate the injection and confining zones and must include additional information about the wells' construction, including the well type, date drilled, information on plugging, etc. See the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for additional information on that requirement.

Information to Submit

EPA recommends that, to satisfy this requirement, Class VI injection well permit applicants provide the following information to the UIC Program Director:

- The numbers, thicknesses, and lithologies of USDWs (including interbedded low permeability zones);
- Information on all USDWs in the AoR and the region, and whether they are currently being used for drinking water; and
- The location of water wells and springs within the AoR.

In addition to tables and other files, the owner or operator may submit maps (e.g., showing the location of water wells on the maps of USDWs described above) and cross sections. If any water quality data or data on hydraulic conductivity, hydraulic gradient, or porosity are available from the sources examined, the owner or operator should reference this information or discuss it in the required analysis of baseline water quality, required at 40 CFR 146.82(a)(c) and described in Section 2.3.9. The owner or operator should ensure that the information submitted is complete and accurate; otherwise, the UIC Program Director may need to request additional information to thoroughly evaluate site hydrogeology and hydrology. For example, if state well databases have incomplete coverage of the area of the proposed well, owners or operators may need to fill in information gaps using on-the-ground surveys or hand searches of health or environmental department records. As noted above, most of the information needed to satisfy this requirement will likely come from existing data. If the data come from USGS or state data sources, it is likely that the UIC Program Director will be satisfied with the quality and accuracy of the data.

2.3.9. Baseline Geochemical Characterization

The Class VI Rule requires baseline geochemical information on subsurface formations including all USDWs in the AoR [40 CFR 146.82(a)(6)]. This encompasses both fluid and solid phase chemical analysis. Information on water chemistry indicates which formations in the stratigraphic column qualify as USDWs and confirms that the proposed injection formation is not a USDW. Geochemical information on both solids and fluids is also needed, in combination with the mineralogic data required at 40 CFR 146.82(a)(3)(iii), to determine whether the interaction of the formation fluids with the injectate and solids will cause changes in injectivity, changes in the properties of the confining zone, or the release of trace elements. This will inform an assessment of the compatibility of the carbon dioxide stream with injection zone fluids and minerals in the injection zone and confining zones, required at 40 CFR 146.82(c)(3) (see Section 3.3). Fluid chemistry also controls the amount of carbon dioxide that can dissolve in the fluid, affecting estimates of carbon dioxide trapping mechanisms and storage capacity. Furthermore, a baseline geochemical analysis will be important for comparison with future data collected via required water quality monitoring above the confining zone [40 CFR 146.90(d)]. If an injection depth waiver is sought, the owner or operator should also provide data on or perform analyses of the geochemistry of USDWs that lie below the injection zone.

Owners or operators will need to review existing data and may need to collect samples and perform analyses for fluid characterization and bulk solid phase chemistry. Guidance for providing information about fluid chemistry and bulk chemical analysis is presented below.

2.3.9.1. Fluid Chemistry

Data Collection and Analysis

Pre-Existing Data

Geochemical data for the site may be available if previous exploration and hydrocarbon production have taken place at the project site, or data may be obtained from other sources such as the USGS's National Water Information System (NWIS; http://waterdata.usgs.gov/nwis/qw) or Produced Waters Database (http://energy.cr.usgs.gov/prov/prodwat/). State geological surveys, water surveys, or water resources research institutes may also have information available.

Owners or operators should submit any available analyses of water or brine from all USDWs and other relevant formations within the AoR. If the owner or operator is requesting an injection depth waiver, data will be needed for the lower confining zone to serve as a baseline for geochemical monitoring. Where pre-existing geochemical data are available, owners or operators should be aware that data quality may vary among sources. Limitations or uncertainties regarding data quality should be noted, including the presence or absence of analyses of duplicate and quality assurance (QA) samples. In relatively homogeneous geological settings and in formations with slow flow rates, analyses taken from areas outside of the AoR may be generally representative of water quality within the AoR and may be used to help understand the geochemistry of the area. However, data will be needed from within the AoR as well. Owners or operators should also consider whether the existing analyses are complete and include a full suite of parameters (see below). Owners or operators may discuss the applicability of pre-existing water quality data sets with the UIC Program Director. Data with limited analyses may still be useful for providing some general characterization, but newer data may also be needed to provide full characterization of water quality within the AoR.

Owners or operators should note the time period over which the samples were taken and whether this information may be sufficient to capture any naturally occurring trends in water chemistry, especially in formations affected by recharge or surface activities. Having sufficient background information will allow owners or operators to distinguish possible effects of injection from naturally occurring variations over the life of the project.

Parameters to Analyze

The specific parameters to be analyzed will depend on the characteristics of the site, each formation being analyzed, and the composition of the planned carbon dioxide stream. Parameters tested should help inform and be consistent with the testing and monitoring planned during the GS project operation and PISC period. Analyses should include basic parameters, such as pH; total dissolved solids (TDS); alkalinity; specific conductivity (SC); and major anions and cations (e.g., Ca^{2+}, Mg^{2+}, K^{+}, Na^{+}, Cl^{-}, Br^{-}, SO_4^{2-}, and NO_3^{-}). Other constituents may differ by formation and be determined based on the mineralogy of the injection and confining formations (as evaluated under 40 CFR 146.82(a)(3)(iii) and discussed in Section 2.3.4). These may include: Sr^{2+}, Fe^{2+}, Fe^{3+}, Al, SiO_2, total organic carbon (TOC), carbon dioxide (aq), and hydrogen sulfide (aq) (if the site is an oilfield) and trace metals (e.g., As, Hg, Cu, Zn, etc.). Additionally, baseline gaseous carbon dioxide should be measured in subsurface formations including all USDWs within the AoR. Samples from proposed injection zones that are depleted hydrocarbon reservoirs may need to be analyzed for hydrocarbons.

Constituents quantified by laboratory methods (e.g., major ions, trace elements, hydrocarbons, and TDS) should be analyzed using approved methods, including ASTM methods, Standard Methods (Greenberg et al., 2005), and EPA-approved methods. The *UIC Program Class VI Well Testing and Monitoring Guidance* can be consulted for more details, including a listing of specific methods that are generally used. An index of EPA methods can be found at http://www.epa.gov/region1/info/testmethods/pdfs/testmeth.pdf.

Sample Collection from Existing Monitoring Wells

If there are monitoring wells in the AoR and they have not been recently sampled, owners or operators should consider taking fresh samples for water quality analysis. For wells in deep formations, including the injection formation, owners or operators may use a sampling apparatus that maintains downhole conditions if such a device is compatible with the construction of the well. If samples are retrieved at the surface, it is crucial that downhole estimates of pressure and temperature be obtained to support modeling of water chemistry speciation under conditions in the injection formation. For shallow wells, EPA guidelines are provided in USEPA (1991) and USEPA (1992). Additional information on sample retrieval and handling is provided in the *UIC Program Class VI Well Testing and Monitoring Guidance*. Following careful sampling procedures during site characterization will provide a reliable baseline for any future monitoring using the same monitoring wells. Owners or operators should also consider obtaining baseline samples over an adequate period of time to capture any natural temporal trends in water chemistry.

Sampling Fluids while Drilling a Stratigraphic Well

If owners or operators drill a stratigraphic well to obtain information to fulfill the requirements at 40 CFR 146.82(a), EPA recommends that samples of formation fluids be taken at that time. Sampling can be conducted using wireline sampling devices. Commercial systems are available that can take fluid samples in addition to obtaining downhole measurements of parameters such as density, pH, and mud contamination. Such equipment has been developed for characterization of hydrocarbon reservoirs and would be applicable to deep formations under consideration for GS. Additional discussion of fluid sampling is provided in Section 4.3. If the owner or operator obtains analyses of pore water in the confining zone(s), owners or operators should note if special methods were used (e.g., squeezing of shale core samples) and whether low volumes precluded analyses of any parameters.

2.3.9.2. Bulk Solid Phase Chemical Analysis

In addition to mineral identification, an elemental analysis of the formation solids in the injection and confining zones and other relevant formations (e.g., the first permeable formation overlying the confining zone) may be needed to evaluate the potential for liberation of trace metals due to lowered pH from injection. Options include X-ray fluorescence (XRF) of whole rock samples, or sample digestion followed by analysis by inductively coupled plasma/mass spectrometry (ICP/MS).

2.3.9.3. Geochemical Calculations and Modeling

With a complete chemical analysis of formation fluids and measurements of pH and temperature, equilibrium geochemical speciation of the constituents in the fluids and saturation indices for relevant mineral phases can be calculated to help identify the major reactions that may affect injection and containment. EPA recommends that this baseline information be compared against results from any future sampling. Two examples of suitable programs are PHREEQC, the current version of the USGS's PHREEQ program (Parkhurst et al., 1980) and the Geochemist's Workbench® (from Rockware, Inc.). Owners or operators should verify that the program selected for this purpose has the capability to perform calculations for waters with the ionic strength of the formation fluids (i.e., brines).

If the owner or operator plans to perform additional analyses beyond basic equilibrium calculations, both of the above-mentioned programs are examples of software that can model reactions of fluids with minerals (identified as required by 40 CFR 146.82(a)(3)(iii)) and gases and can incorporate reaction kinetics (rates) and transport of fluids. The advantage of such modeling is that it allows consideration, prior to injection, of the types of reactions (e.g., loss of carbonates, precipitation of carbonates, long-term dissolution of silicates) that can change permeability, release undesirable elements, alter injectivity, and affect ultimate storage capacity. The owner or operator may choose to conduct reactive transport modeling to account for any significant effects of geochemistry while delineating the AoR. Additionally, see Section 3.3 for discussion of geochemical modeling as part of a demonstration of compatibility between the injectate and formation fluids and formation solids.

<u>Data Collection and Analysis</u>

If pre-existing data on the geochemistry of solids or core samples from previous characterization work are available, the owner or operator should discuss their availability and quality with the UIC Program Director, along with whether new core samples are needed for the baseline characterization and if so, which formations should be tested.

Bulk chemical analysis of a powdered, solid sample may be obtained by XRF. Alternatively, samples may be digested and the extracts analyzed by inductively coupled plasma/atomic emission spectrometry (ICP/AES) or ICP/MS. Sample digestion can be done with EPA Method 3052 (Microwave Assisted Acid Digestion of Siliceous and Organically Based Materials). For the analysis stage, EPA Method 6020A (ICP/MS) or EPA Method 6010-C (ICP/AES) can be used.

Information to Submit

Owners or operators should submit the following information related to the baseline geochemistry of the site:

- The source of the data (if using existing analyses);
- Dates, locations (on maps), formations, and depths from which samples were taken;
- Sampling methods and sample preservation methods used;
- Analytical methods;
- QA data or QA samples (duplicates, blanks, matrix spikes); and
- A discussion of the results, including any anomalous data, and a discussion of the spatial representativeness of the data for a given formation.

Results should be presented in tabular and graphic form and plotted on a map of the AoR, if possible. The report on fluid chemistry should also include, temperature, SC, and pressure values taken at the time of sampling. In addition to submission of baseline fluid chemistry in tabular form, owners or operators may present their data in graphical form (e.g., using a Piper diagram (Piper, 1944) or a Stiff diagram (Stiff, 1951)).

To support the UIC Program Director's evaluation of the data, the owner or operator should demonstrate that the data are representative of the injection and confining zones, appropriate formation(s) above the confining zone, including USDWs, and, if needed, potential secondary confining zones, consistent with 40 CFR 146.82(a)(6) and 146.83(b). If geochemical data (e.g., analysis of the bulk chemistry of the solids) indicate high concentrations of trace elements, the owner or operator should evaluate injection and confining zone mineralogy and whether any trace elements are associated with minerals that are anticipated to be dissolved under the low pH conditions that may occur due to injection of carbon dioxide. In some circumstances, the owner or operator may also choose to analyze the presence of trace elements in the first permeable formation overlying the confining zone.

If vintage data are used, the owner or operator should demonstrate to the UIC Program Director that they are adequate to establish a reasonable baseline prior to injection. The owner or operator should also identify and discuss any spatial variability in water quality data.

2.3.10. Geophysical Characterization

To support the requirement at 40 CFR 146.82(a)(3)(iii) to submit data on the injection and confining zone(s), owners or operators can use a variety of field data, which may include seismic surveys or other geophysical methods. Although they are an indirect means of measurement and subject to uncertainty and interpretation, geophysical methods provide a means of generating information about the subsurface in lieu of physically sampling the layers of interest. They can also provide information over a larger area than cores alone can reasonably provide. Depending upon the scale and resolution of the investigation, geophysical methods (e.g., seismic and other surface and cross-well geophysical techniques) can be used to estimate the stratigraphy, structure, extent, and thickness of subsurface units. Data collected for a baseline geophysical survey will also serve as the reference point for future monitoring as required at 40 CFR 146.90(g)(2) and as described in the *UIC Program Class VI Well Testing and Monitoring Guidance.*

There are four main types of geophysical methods: seismic, gravity, magnetic, and electrical/ electromagnetic (EM). These methods can image a large area of the subsurface without penetrations (i.e., wells or boreholes). EPA recommends that owners or operators deploy at least one of these methods during site characterization as they can provide good spatial coverage of a project area and may be especially useful in regions where subsurface geology is heterogeneous and/or wells are sparse. Owners or operators should demonstrate that their selected method will achieve adequate resolution at the depths needed.

In selecting the specific geophysical method(s) to use, owners or operators should consider the following:

- The goals of the survey and types of information desired;
- The desired resolution;
- Subsurface lithologies;
- Subsurface heterogeneity;
- Known or suspected faults and whether their geometries are likely to be imaged by the type of survey considered;
- Locations of existing wells to use for downhole methods;
- Whether an injection depth waiver is sought; and
- The availability of other information from cores, well logging, and other sources to aid in interpretation of the data.

Table 2-1 summarizes the status and utility of the various geophysical methods, and Table 2-2 outlines the phases of a GS project to which various geophysical techniques may be suited. The types of geophysical methods are described in Sections 2.3.10.1 through 2.3.10.4, followed by a discussion of what information should be submitted to the UIC Program Director. Additional detail on all four types of methods is provided in the Appendix.

Table 2-1: Applicability of Geophysical Techniques to Geological Features of Interest

	SEISMIC						GRAVITY		ELECTROMAGNETIC/ ELECTRICAL			MAGNETIC
<u>*Investigation of*</u>	*2D*	*3D*	*VSP**	*3D-VSP*	*Cross-well*	*Borehole Microseismic*	*Aerial & Surface Gravity*	*Borehole Gravity*	*Natural Source*	*Controlled Source*	*ERT**	*Aerial & Surface Magnetic*
Near Borehole and Shallow Subsurface			W	W	W	W		W		W		
Field-Wide Subsurface Studies	W	W		W		P	W		W	W		W
Stratigraphy	W	W	W	W	W		W[1]	W	P	P	W	P[2]
Thickness	W	W	W	W	W			W			W	
Structure 0-100 m				P		P	P		P	P	P	P
Structure 100 m – 1 km	W	W		W	W	W	P	P	P	P	W	P
Structure >1 km	W	W		W	P	W	W[3]	P	W	W	P	W[3]
Fault/Fracture	W	W		W	W	W[4]	P		P[5]	W[5]	P[5]	W
Porosity							P	W	W[6]	W[6]	W[6]	
Pore Pressure	P	W	P	?	P							
Abandoned Wells[7]											W	W[8]

W = Well Suited (e.g., already in use for site characterization with good results);
P = Potential (e.g., could be used, but often not used because better alternatives are available or in use but results are not as resolved as desired).

[1] Valid for flows, sills, channel fills, or other discontinuous units with high density contrast
[2] Chiefly for iron-mineral bearing units (e.g., mafic intrusions, red-beds, etc.)
[3] Characterizes depth to basement
[4] Valid only if faults/fractures are actively undergoing deformation
[5] Valid only in non-porous formations
[6] Qualitative estimates compared to nearby formations
[7] For additional geophysical techniques on finding abandoned wells see the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*
[8] Valid only if wells are cased in the near surface with metal
*VSP = Vertical Seismic Profile; ERT = Electrical Resistance Tomography

Table 2-2: Stages in a Geologic Sequestration Project where Geophysical Techniques May Be Applicable

	SEISMIC						GRAVITY		ELECTROMAGNETIC/ ELECTRICAL			MAGNETIC
APPLICABLE DURING	*2D*	*3D*	*VSP*	*3D VSP*	*Cross-well*	*Borehole Microseismic*	*Aerial & Surface Gravity*	*Borehole Gravity*	*Natural Source*	*Controlled Source*	*ERT*	*Aerial & Surface Magnetic*
Preliminary Investigation	X						X		X	X		X
Site Characterization	X	X	X	X	X		X	X		X		X
Injection-Phase Monitoring	X	X	X	X	X	X		X		X	X	
Post-Injection Site Care	X	X	X	X	X	X		X		X	X	X

2.3.10.1. Seismic Methods

For site characterization, seismic methods are well suited for determining formation thickness, stratigraphy, structures, and the location and/or attributes of faults (Table 2-2). These methods work best for characterizing simple, homogenous geologic settings where supplementary sources of data such as well logs, outcrop data, and other geophysical surveys are available. More detailed information on seismic methods and processing is available from numerous sources, including introductory guides such as: *A Handbook for Seismic Data Acquisition* (Evans, 1997), *Environmental Geology – A Handbook* (Knödel et al., 2007), and *An Introduction to Geophysical Education* (Kearey et al., 2002). For additional discussion on the principles and deployment of seismic methods, see the Appendix.

<u>Data Collection and Analysis</u>

Pre-Existing Data

Because seismic methods are used by a variety of industries, pre-existing seismic surveys may be available for the area of interest, especially if the region has been the subject of hydrocarbon or other mineral exploration. Existing seismic data will most likely be 2D. Some seismic data may also be available for free from government agencies; for example, the USGS maintains the Seismic Data Processing and Interpretation Group, which houses the National Energy Research Seismic Library (NERSL) and has been acquiring seismic reflection data since the mid-1970s. Processing methods for seismic data have improved greatly in recent years, and reprocessing vintage raw data can lead to improved resolution or identification of features not identified in the original survey (Hyne, 2001). Owners or operators should recognize that the quality or resolution of publically available or free data may not be suitable for GS project site characterization.

Seismic Deployments

Seismic deployment can be done on the surface (2D or 3D), in boreholes, or a combination of both. If owners or operators are conducting a new seismic survey for purposes of site characterization, EPA recommends that the decision regarding the type of deployment be based upon what is known about site geology and features that may need imaging. Furthermore, it should be kept in mind that seismic data acquired during site characterization will serve as the baseline for any geophysical monitoring activities conducted during the injection phase of the project. Because 2D surveys produce "slices" of the subsurface, they are not optimal in settings where significant lateral heterogeneity is expected or faults are known to be present. 3D surveys may be preferable to 2D surveys when characterizing sites with complex or variable subsurface geology, where subsurface geology is not well constrained, where improved resolution is necessary, or where high well costs require greater certainty in subsurface characterization. A vertical seismic profile (VSP) can help increase the resolution and accuracy of other seismic surveys, can help with pore pressure estimation, and can help to link geology derived from other borehole logs to seismic attributes (Kearey et al., 2002). When imaging thin beds, cross-well seismic methods may be useful; they offer good resolution and can fill the resolution gap between high-resolution well cores and 3D surface data or to help correlate structure between well bores. Cross-well imaging may be considered in areas with abundant subsurface penetrations in locations that will allow imaging of features of interest.

Additional Seismic Data Analysis

Pore Pressure Interpretation

If seismic data are of adequate quality, owners or operators may consider using the data to remotely estimate subsurface pore pressure. Any seismic data that yield an accurate seismic velocity can be used to approximate effective stress and estimate pore pressure. However, not all seismic data meet this criterion because accurate velocity values are not needed to image the subsurface. Ensuring that seismic data can also be used for pore pressure prediction requires planning. Once accurate velocity data have been obtained, there are numerous methods available to convert velocity to pore pressure. These methods tend to work best in developed basins filled with shales and sands. The main disadvantage of this technique is that it requires extensive data processing and interpretation, which may introduce large errors and necessitate basin-specific correction factors during velocity processing.

Seismic Stratigraphy

Because seismic reflections follow large-scale bedding, the geometry of the reflections allows the delineation of features such as unconformities, depositional sequences, and unit thicknesses (e.g., Vail et al., 1977). EPA recommends the integration of seismic data with lithologic data from cores, well logs, and other data to assist in interpretation of depositional features and environments. If the owner or operator undertakes a detailed analysis, lithologies and other characteristics identified at wells and boreholes can be correlated to seismic attributes, which can then be used to predict subsurface properties at other locations through various methods, including regression or neural networks. Stratigraphic features identified in this manner may help in identifying features (e.g., barriers, channels, fans) that might affect storage capacity and migration of carbon dioxide.

2.3.10.2. Gravity Methods

Gravity methods are well established for determining stratigraphy and formation thickness and have possible usefulness for identifying structure, faults, and porosity (Table 2-2). Because detection of faults and structural features using gravity data depends upon contrasts in density, EPA recommends that owners or operators reserve the use of gravity methods for basins with varied lithologies. Salt domes and igneous intrusions are the easiest types of lithologic features to image because they generally have a high density contrast with surrounding formations. Faults may be detected with gravity data if units with contrasting density or regions with different sedimentary thicknesses are juxtaposed. EPA also recommends that owners or operators consider the types of faults that are likely to occur in the project area; small faults or faults with large displacement occurring in discrete steps are more difficult to detect with gravity data than large planar faults. Vertical faults are especially difficult to detect using surface gravity methods (Barbosa et al., 2007).

<u>Data Collection and Analysis</u>

Aerial and land-based gravity surveys are commonly performed by government agencies. They are widely available and are often free. However, data available from such sources may be undersampled for many site characterization purposes or may not have been targeted at shallow to moderate-depth sedimentary sequences. Gravity data may be more likely to exist than other types of geophysical data if investigations into deep saline formations have previously occurred at the site.

Where the owner or operator deploys a gravity survey for the purpose of site characterization, the choice of deployment (land-based, aerial, or subsurface (boreholes)) is usually based on factors such as desired resolution and site-specific geology. Broad land-based or aerial gravity surveys may suffice for detecting large-scale changes in the thickness of basin fill and other basin-wide features, while more detailed surveys will be needed to detect finer features such as the distribution and thickness of specific formations. Borehole surveys can be used to determine layer thickness and aid in determination of lithologic composition. In regions that are laterally variable, borehole gravity data may indicate features such as salt domes and reefs even if they do not intersect the borehole (LaFehr, 1992).

2.3.10.3. Electrical/Electromagnetic Geophysical Methods

Electrical and EM methods have potential application in certain formation types for delineating structure, stratigraphy, faults, and porosity (see Table 2-2 for additional details). Resolution is low for most electrical/EM methods compared to seismic methods. However, the depth and breadth of electrical/EM surveys can provide valuable information on the regional geologic framework at low cost (Orange, 1992). Additional information on EM methods for GS site characterization is presented in the Appendix.

Data Collection and Analysis

Electrical survey data are not likely to be available for a proposed Class VI injection well site unless the region has previously been characterized for hydrocarbon or ground water resources.

Data can be collected aerially, from the surface, or from the subsurface. For a detailed site characterization, EPA recommends the use of subsurface deployments when possible; this is because subsurface techniques are generally of superior quality compared to most surface methods, and heterogeneous surface conditions tend to attenuate the signal (Wilt et al., 1995). See the Appendix for additional details on the various types of electrical and EM methods.

2.3.10.4. Magnetic Geophysical Methods

Magnetic methods are suited for imaging faults and large-scale structures and may also be useful for smaller structures and stratigraphy (Table 2-2). Faults and other structural features in both basement rocks and overlying sedimentary formations can be imaged, but formation characteristics are difficult to determine using magnetic data (Ugalde, undated). Because magnetic data are non-unique and do not represent specific lithologies, additional data from other types of geophysical surveys or other sources (boreholes, outcrops, etc.) are needed to improve magnetic data interpretation (Jordan and Hare, 2002). The Appendix provides additional detail on magnetic geophysical methods.

Magnetic methods are sensitive to human infrastructure. As a result, they are not useful in populated or developed areas because buildings, pipes, and wires obscure the geologic signal. They are, however, well suited for locating abandoned, cased wells that may need corrective action. See the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for additional information.

Data Collection and Analysis

Magnetic surveys have already been conducted over the majority of North America. However, the resolution of these surveys may not be high enough for site characterization purposes. High-resolution data are more likely to have been collected for hydrocarbon-producing basins and areas targeted for mineral exploration.

Information to Submit

In reporting the results of geophysical surveys, EPA recommends that owners or operators submit to the UIC Program Director the following information:

- The source of the data and whether they are vintage or newly collected;
- The type of survey and other details of the deployment (e.g., date, location/areal extent of the survey, vendor who performed the survey);
- If boreholes were used, the locations of the boreholes;
- Type of data processing, including any reprocessing of vintage data;

- Images, with locations of profiles indicated on a map and salient geologic features identified (including formations below the injection zone where an injection depth waiver is sought);
- Assumptions and limitations associated with the method, data, and their interpretation;
- A narrative discussing the results in the context of the site geologic conceptual model; and
- If the data suggest non-unique interpretations, the owner or operator should address alternative interpretations.

To support the UIC Program Director's evaluation of the data, the owner or operator should demonstrate that the geophysical survey results provide an image of the subsurface at a suitable resolution for evaluation of the injection and confining zones. The owner or operator should also demonstrate that the results of the survey are consistent with other data such as geologic maps and lithologic information from cores. If the owner or operator submits a new survey to serve as a baseline for future monitoring, EPA recommends that the survey be georeferenced for comparison against future surveys. If vintage data are submitted, the owner or operator should demonstrate to the UIC Program Director that the data provide adequate coverage of the AoR and are of sufficient quality.

2.3.11. 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 a USDW [40 CFR 146.90(h)]. Carbon dioxide detection above background levels in soil gas or at the surface does not necessarily indicate USDWs have been endangered, but that a leakage pathway or conduit exists at some point in the operation.

Baseline surface air and soil gas data should be collected if the UIC Program Director requires surface air and soil gas monitoring as part of the Testing and Monitoring Plan. Baseline data on carbon dioxide concentrations and fluxes collected prior to operation will provide data for comparison to levels during and after the operational phase of the project in order to detect any potential leakage. The owner or operator or the UIC Program Director may opt to perform surface air and soil gas monitoring during the site characterization phase to provide a baseline if they plan to incorporate surface air and soil gas monitoring technologies at a later date.

The AoR should be characterized with respect to properties that may affect the baseline data, such as soil type, soil organic carbon content, vegetation type and density, topography, and surface water hydrology. Different approaches can be used to conceptualize the system, such as ecological modeling to identify the sources and sinks and/or flow and transport modeling to understand the flow paths and dispersion processes.

Data Collection and Analysis

Overall, the spatial distribution of soil carbon dioxide fluxes and concentrations should be determined on a site-specific basis. A more precise determination of baseline would require repeated measurements at several fixed sites to capture any seasonal or diurnal variations. In particular, EPA recommends that the location of soil gas and/or surface air sampling points be based on the following considerations:

- Avoiding areas with highly fluctuating background concentrations, based on previously recorded data;
- Selecting potential point-sources, including wellheads, artificial penetrations, and fault or fracture zones. A transect-profiling approach may be used for linear features, such as faults (see ASTM, 2006); and
- 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 (2006) for discussion of establishing a soil sampling grid.

During measurement of concentration and fluxes, EPA also recommends monitoring soil temperature and moisture. Some other important data, such as atmospheric temperature, pressure, and wind speed and direction can be obtained from a nearby weather station. The data collected should be analyzed using regression analysis to develop empirical relationships between correlated parameters for the entire area or the chosen sub-areas, which can then be used to predict background carbon dioxide fluxes expected under a given set of environmental conditions (Oldenburg et al., 2003).

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 baseline determination and monitoring strategy that efficiently meets all objectives (e.g., to meet the requirements of the Class VI Rule and Subpart RR of the GHG MRR, promulgated under the authority of the Clean Air Act). In some cases, separate technologies (e.g., eddy covariance towers versus soil gas probes) may be used to meet specific objectives. However, it is likely that data collected from multiple techniques will be complementary and useful in data analysis and interpretation for all regulatory programs. Further information on technologies that can be used for soil gas and surface air monitoring can be found in the *UIC Program Class VI Well Testing and Monitoring Guidance* and the Subpart RR General Technical Support Document (USEPA, 2010).

Information to Submit

If baseline surface air or soil gas analyses are needed, EPA suggests that owners or operators submit the following:

- Site characteristics: soil type, soil organic carbon content, vegetation type and density, topography, surface water hydrology;
- Sampling locations (in map form) and dates;
- Soil temperature and moisture data and atmospheric conditions;
- Sampling and analytical methods, including detection limits;
- Results presented as concentrations and fluxes in tabular and graphic form, including QA samples and analyses;
- Methods and results of regression analyses; and

- Methods and results of any ecological modeling performed, including input data, outputs, and sensitivity analyses.

To support the UIC Program Director's evaluation of surface air and soil gas data, the owner or operator should demonstrate that the locations sampled represent a reasonable grid size and that potential point sources are represented and will serve as a good baseline to which future monitoring data can be compared. The owner or operator should also demonstrate that seasonal and diurnal variations in carbon dioxide levels have been captured and describe the variability in the data for future reference. If an inadequate time series of analyses was performed or if there are concerns regarding the quality of analytical data, the owner or operator may be asked to submit additional data.

3. Data Synthesis for Demonstration of Site Suitability

The information required at 40 CFR 146.82 and described in this guidance provide comprehensive data and descriptions for many properties of the proposed project site (e.g., porosity, geochemistry). These data do not individually provide a complete picture of the site to demonstrate that it can safely receive and confine the carbon dioxide. Together, however, this information can form a comprehensive picture of the site and demonstrate whether it is a good candidate for GS and meets the requirements at 40 CFR 146.83. This section describes how the owner or operator can synthesize the information collected during site characterization to demonstrate site suitability.

- Information on **facies changes**, required at 40 CFR 146.82(a)(3)(iii) supports the development of the site conceptual model and an understanding of how the carbon dioxide plume will move in the subsurface; it can also inform the AoR modeling. Section 3.1 briefly discusses how owners or operators may present geologic information (e.g., cores, outcrop data, seismic surveys, and well logs) to provide an illustration of facies changes within the subsurface;
- **Structural information on the injection and confining zones** is necessary to demonstrate how the carbon dioxide will be confined in the injection zone and that there are no potential leakage pathways. Section 3.2 describes how information collected, including maps, cross sections, and seismic data, support a description of the site structural geology;
- **Carbon dioxide stream compatibility** with the well and subsurface formations and fluids is important to the long-term viability of the injection operation. The owner or operator must provide information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s) [40 CFR 146.82(c)(3)]. This information will show that the well will not be damaged by the injectate and that no geochemical reactions within the injection and/or confining formations will affect the storage and/or containment in a manner that is not accounted for in planning or reduce the storage capacity of the site. Section 3.3 describes how information on the injectate, fluids in the injection zone(s), minerals in the injection and confining zones, and well materials can be combined and evaluated together to demonstrate compatibility of the carbon dioxide stream;
- Information on the **storage capacity of the injection zone** is important to demonstrate that the site, based on site-specific information such as thickness, porosity, geochemistry, etc., has sufficient capacity to receive the amount of carbon dioxide anticipated to be injected as required at 40 CFR 146.83(a)(1). Section 3.4 briefly discusses approaches that may be considered to evaluate storage capacity;
- Information on **confining zone integrity** supports a demonstration that the confining zone will not allow migration of carbon dioxide outside the intended injection zone(s) and that the site meets the requirements at 40 CFR 146.83(a)(2). Section 3.5 describes how information collected, including lithologic and stratigraphic data, structural data, core analyses, and formation testing data can support a demonstration of confining zone integrity; and

- A demonstration of **secondary confinement** may be appropriate to ensure USDW protection, impede vertical fluid movement, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation and remediation. Section 3.6 describes the information that is needed to make this demonstration and how the owner or operator would present it to the UIC Program Director if it is required per 40 CFR 146.83(b).

Some aspects of this data synthesis involve combining geologic, geochemical, and geomechanical information and explaining how they demonstrate that the site meets the Class VI Rule requirements. Other aspects may require additional analysis, such as modeling. The sections below present recommended approaches for compiling, synthesizing, and presenting the necessary information.

Thinking of the proposed site in the context of this larger analysis can help guide the site characterization process by identifying the big questions about the site that need to be answered and tailoring the information collection to ensure that the data support a determination that the site is appropriate for GS. This synthesis also supports the AoR modeling, project plan development, and effective management of injection operations. It can also facilitate the UIC Program Director's review of the application and may improve public acceptance of the project by demonstrating to the public how the geologic data support a determination of site suitability.

3.1. Facies Analysis for the Project Site

The Class VI Rule, at 40 CFR 146.82(a)(3)(iii), requires owners or operators to provide information on facies changes in the injection and confining zones. Understanding facies changes at the injection site will help the owner or operator develop a geologic conceptual model that describes the depositional environments and the resulting distribution of lithologies. Because lithofacies exert control on porosity, permeability, and mineralogy, a good facies analysis will help in anticipating heterogeneity in these properties and the associated effects on the injection and storage capabilities of the site. Understanding of subsurface heterogeneity can also be used to select the placement and design of injection and monitoring wells as well as refine the parameterization of multiphase flow modeling for the site (see the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*). This section briefly discusses considerations and data needed for assessing facies changes.

Data Collection and Analysis

An analysis of facies changes and identification of the spatial distribution of lithofacies within different layers/formations may require integration of several types of information gathered during site characterization. Lithofacies distribution for computational modeling can be estimated using geostatistical approaches (e.g., geometric object-based methods or cell-based methods).

The data needed for facies analysis can include geologic maps, isopach maps, stratigraphic columns, wireline logging data, descriptions and analyses of core samples, and seismic data. For example:

- Descriptions and analyses of core samples will provide information on a number of relevant characteristics including mineralogy, cross-bedding, grain sizes, sorting, fine-grained interbeds, and cementation;
- Seismic stratigraphic features can be used to identify stratigraphic sequences; and
- Wireline logging data can provide information on properties such as lithology and porosity and can be used to confirm the depths of formations.

Correlation of these various data sources can provide a three-dimensional representation of the subsurface stratigraphy. Owners or operators should bear in mind that there may be considerable uncertainty in facies models given the need to interpolate between what may be sparse data points and logistical challenges to obtaining representative data. A brief discussion of facies considerations for GS and some useful references are provided in the Appendix.

Information to Submit

Owners or operators should prepare a discussion of the inferred depositional environment(s) at the project site in the context of the site geologic conceptual model. The discussion should address, at a minimum:

- The implications for connectivity within the injection formation and the suitability of the confining zone;
- Lithofacies distributions mapped in the injection and confining formations, including the distributions of properties such as porosity and permeability for each lithofacies;
- The potential for preferential flow paths;
- Diagenetic processes that may affect present-day hydrogeologic properties; and
- Uncertainties associated with the data and with the resulting facies model.

The narrative should reference appropriate data, maps, geophysical images, cross sections, and stratigraphic columns.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that correlation among data types is reasonable and that the available data support facies interpretations. The owner or operator should also assess possible preferential flowpaths or barriers and their implications for movement of carbon dioxide and for the quality of the confining zone. The report should also demonstrate how the facies interpretation informed the development of the site geologic conceptual model for the AoR delineation modeling.

3.2. Structure of the Injection and Confining Zones

The Class VI Rule, at 40 CFR 146.82(a)(3)(vi), requires that geologic and topographic maps and cross sections illustrate the geologic structure of the local area. An assessment of the structural geology of the project area is a crucial part of a demonstration that the well will be sited in an area that meets the requirements of 40 CFR 146.83(a), and owners or operators should provide a thorough discussion that integrates all relevant information compiled during site characterization. This may include use of:

- Geologic and structural maps and cross sections (see Section 2.3.1);
- Isopach maps (see Section 2.3.3);
- Results of geophysical surveys (see Section 2.3.10); and
- Data from well logs and core analyses (see Sections 4.1 and 4.2).

Data Collection and Analysis

EPA encourages the use of all available data in the AoR and the surrounding region in this analysis. However, owners or operators should be alert to the quality of vintage data, especially if samples or raw data are not available.

EPA strongly encourages the use of seismic data when evaluating structures at a GS site and emphasizes the usefulness of 3D seismic data or a grid of 2D seismic profiles. Lower or fair quality 2D data can be extremely useful for identifying larger faults, reservoir limits, and for general regional mapping. If geology is complex, especially around the point of injection, and greater detail is needed, 3D data are superior. If seismic profiling is not feasible at the project site, owners or operators should consider whether other geophysical methods will provide useful data.

In the evaluation of regional and local structural geology, EPA recommends that the owner or operator illustrate and discuss major structural features that will affect the migration of carbon dioxide in the subsurface, such as:

- Folds and their trend and plunge;
- The presence of domes;
- The strike and dip of unfolded beds;
- The locations, orientations, types of faulting (normal, reverse, strike-slip, thrust), and depths of faults; and
- Units juxtaposed by faults.

Owners or operators should discuss the role of structural traps in providing for secure storage (in a manner similar to the role of these structures in forming oil and gas traps). Such structures should limit the migration of carbon dioxide. The disadvantage of a closed structure, however, is that a confined column of carbon dioxide may form, putting stress on the confining zone from buoyant forces. In such settings, extra care may be needed in constraining the capillary pressure and geomechanical stability of the confining zone (Chadwick et al., 2008).

In unfolded, gently-dipping sequences, carbon dioxide may potentially migrate long distances and the AoR may be larger. In such settings, careful attention should be paid to the presence of higher-permeability preferred flowpaths. Also, more data may be needed to accurately constrain structural surfaces that have minimal topography because uncertainties in the data will have a greater impact on predictions of carbon dioxide movement.

Owners or operators should clearly indicate whether faulting is likely to enhance the project site by providing a trap, or potentially compromise the confining zone. Fault-bounded trapping through juxtaposition of the injection zone with a low-permeability layer may provide a favorable storage formation. Non-transmissive faults that transect the confining zone, however, may pose a leakage risk, and should be carefully evaluated for their stability and sealing capacity (see Section 2.3.2 for additional information on fault analyses and Section 3.5 for information on confining zone integrity).

Information to Submit

The owner or operator should prepare a narrative for the UIC Program Director that clearly describes how the local and regional geologic structure are conducive to GS and that an adequate confining system is present. This discussion should describe how the structure of the injection and confining zones fit into and support the development of the site conceptual model developed for delineation of the AoR. Owners or operators should identify which features support the capacity of the site to contain carbon dioxide, including the role of structural traps. Potential weaknesses should also be addressed (e.g., if faults are present, whether data indicate that they are sealing). The owner or operator should also discuss whether there are alternative interpretations to the data.

Because this evaluation is based on data collected to meet other requirements, the owner or operator should reference the relevant data and associated uncertainties and describe how the data were used to support the structural analysis. Owners or operators should address the representativeness of these data and their consistency with other site data as well as with region-wide data (e.g., maps and geophysical images) and explain limitations when using these data to develop a conceptual model of the subsurface in the entire project area. The owner or operator should demonstrate that sufficient data were used to evaluate the structural geology, keeping in mind that the amount of data needed will be site-specific to some degree. For example, fewer data may be needed in areas with simple structures than in complex areas.

3.3. Compatibility of the Carbon Dioxide Stream with Subsurface and Well Materials

The Class VI Rule requires owners or operators to report on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well [40 CFR 146.82(c)(3)]. This demonstration is needed to support an understanding of (1) whether subsurface interactions among the injectate, fluids, and solids will lead to precipitation or dissolution of minerals such that permeability, porosity, and injectivity may change; (2) if geochemical changes due to the introduction of large amounts of carbon dioxide into the subsurface might cause trace elements such as lead or arsenic to be liberated from subsurface solids; and (3) if interactions among the fluid, carbon dioxide, and cement might cause deterioration of the cement such that the cement sheath would become a conduit for fluid migration.

3.3.1. Compatibility of the Carbon Dioxide Stream with Fluids and Minerals

The compatibility demonstration will use information gathered during site characterization and during execution of the formation testing program, including:

- Chemical analyses of fluids in the injection zone and, if available, the confining zone (see Section 2.3.9);
- Mineralogy of the injection and confining zones (see Section 2.3.4);
- Bulk chemical analyses of solids in the injection and confining zones (see Section 2.3.9);
- Pressure, temperature, and pH in the injection zone and, if available, the confining zone (see Section 2.3.9); and
- The chemical characteristics of the injectate (see the *UIC Program Class VI Well Testing and Monitoring Guidance* for information on this analysis).

<u>Data Collection and Analysis</u>

To make a demonstration of compatibility, the owner or operator may take one or more of a few approaches, synthesizing information as appropriate: perform geochemical modeling, conduct bench-top laboratory experiments, and/or (in limited circumstances) provide an in-depth but qualitative discussion of potential geochemical reactions based on site data and GS literature. Guidance and recommendations for these approaches are presented below.

Owners or operators are strongly encouraged to perform **geochemical modeling** to assess potential impacts of injection on the subsurface. Equilibrium speciation modeling with programs such as PHREEQC or the Geochemist's Workbench® can be used to obtain saturation indices to predict the potential for mineral precipitation or dissolution, as described in Section 2.3.9. Such programs can also be used to model the reactions of fluids with minerals and gases and can incorporate reaction rates (kinetics). These geochemical models have also incorporated some capacity for 1D (PHREEQC) or 2D (Geochemists' Workbench®) reactive transport simulations. Other geochemical models that may be used in GS applications include SOLMINEQ.88 (Kharaka et al., 1989) and EQ3/EQ6 (Wolery, 1992). STOMP and TOUGHREACT are reactive transport models developed by Pacific Northwest National Laboratory and Lawrence Berkeley National Laboratory (http://esd.lbl.gov/TOUGHREACT/), respectively. They incorporate multiphase fluid and heat flow with geochemical reactions. TOUGHREACT has been used to model GS scenarios and anticipated mineral trapping (e.g., Xu et al., 2007; Xu et al., 2005). See the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for additional information on multiphase reactive transport modeling.

In performing geochemical modeling, the owner or operator should be aware of and discuss limitations in modeling capabilities and resulting uncertainties. In particular, this includes limitations in available thermodynamic and kinetic data. Gaus (2010) presents a more in-depth discussion of geochemical interactions in a GS context. Owners or operators are encouraged to take advantage of literature and research on suitable models and available thermodynamic and kinetic data. For example, Krupka et al. (2010) published a literature review on thermodynamic data for modeling of carbonate reactions associated with GS. A 2007 book by Marini covers thermodynamics, kinetics, and reaction path modeling as applied to GS. Gaus et al. (2008) have published a review article on geochemical and solute transport modeling for GS. Palandri and Kharaka (2004) have published a compilation of kinetic data.

Owners or operators may consider **bench-top laboratory experiments** to simulate reactions among subsurface solids, fluids, and the injectate. If an owner or operator plans to use an experimental approach, EPA recommends using core samples of the injection and confining zones (see Section 4.2). If a sufficient sample is not available, rock and mineral samples representative of the subsurface at the project site may be used with documentation that they are very similar to the mineralogy of the injection and confining zones. The fluid phase should be formulated to mimic the formation fluids in the injection zone, and the carbon dioxide phase should include anticipated impurities. Pressure and temperature conditions should be representative of conditions at depth during operation at the project site.

The duration of the experiment should allow for establishment of steady state conditions prior to introduction of carbon dioxide. After introduction of carbon dioxide, the experiment should be conducted for a sufficient time frame to result in measurable changes to the rock sample and for the fluid composition (pH, major ions) to achieve steady state; this may entail a run time of several weeks or a few months, depending upon the mineralogy of the sample and anticipated reaction rates among the fluid, minerals, and carbon dioxide. Fluid chemistry should be tracked during the experiment, and the solid materials should be analyzed after completion of the run. Rock/mineral samples should be evaluated for changes in porosity, permeability, and mineralogy by any of the methods described in Sections 2.3.4 and 2.3.5.

Alternatively (and with the UIC Program Director's agreement), the owner or operator may provide a detailed **discussion of the geochemical characteristics** of the injection and confining zone(s) and the injectate composition in the context of what is known in the literature about the reactivity of the minerals and anticipated reactions with the carbon dioxide and carbon dioxide-rich brine.

To make a convincing demonstration, this discussion should draw extensively on the geologic, mineralogic, geochemical, and GS literature and should tie this information closely to the known properties of the subsurface geochemistry and mineralogy at the project site, based on data collected during site characterization. Information from the literature such as mineral dissolution and precipitation rates should be considered in this evaluation, and the owner or operator should take note of limitations in available data (e.g., variations among studies, differences between field- and laboratory- derived data). Geochemical studies from GS pilot projects may be referenced if they have properties similar to the project site. Such a discussion will be qualitative in nature and is likely to be appropriate only in limited situations, such as where the geology is uncomplicated and homogeneous, the mineralogy is simple and relatively unreactive, and the injectate is known to be relatively free of impurities such as sulfur dioxide, which may give rise to very low pH values in the injection formation (Xu et al., 2007). If an owner or operator plans to use this approach, he or she should consult with the UIC Program Director. If this approach is supported by the UIC Program Director, the owner or operator should submit a thorough discussion that cites relevant literature and references mineralogic and geochemical data collected during site characterization.

Information to Submit

If geochemical modeling is performed, owners or operators should submit:

- The model used;
- Input data in tabular form;
- Modeling parameters and data used (e.g., activity coefficient model, identification of thermodynamic database, solid phases selected, reactions modeled, kinetic data, etc.);
- Results in tabular and graphical form;
- A thorough narrative interpreting the results and their applicability to the project; and
- A discussion of limitations and uncertainties associated with the modeling.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that the information on which the model is based is complete and that the model is appropriate for the GS scenario. If significant mineral precipitation or dissolution is predicted, the owner or operator should discuss its impact on injectivity and whether precipitation or dissolution of minerals at the interface with the confining zone might either diminish or improve the sealing capabilities of the confining zone.

In reporting the results of experimental work, owners or operators should submit:

- A thorough description of the experimental method;
- A description of the composition and origin of solids used;
- The chemistry of the input solution and the carbon dioxide phase (i.e., impurities);
- Porosity and permeability of the rock sample prior to experimentation;
- Plots of solution chemistry with time during the experiment;
- Geochemical reactions (e.g., dissolution and precipitation of minerals) that have taken place;
- Methods of evaluating permeability and porosity at the end of the experiment and the resulting values; and
- A narrative discussing the results and their implication for long-term behavior of the site, including changes in injectivity, the degree of mineral trapping, and how this information relates to the AoR delineation.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that the test conditions and input materials are representative of the injection formation and the downhole conditions, that the test was run for an adequate period of time, and that the fluid chemistry achieved steady state.

If data are available from more than one location within the AoR, the owner or operator should provide an analysis that encompasses any variability in fluid chemistry and discuss any impacts on the resultant modeling or experiments. Similarly, if core analyses indicate lithologic and mineralogic heterogeneity, this too should be discussed.

3.3.2. Compatibility with Well Materials

Owners or operators must provide information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s) [40 CFR 146.82(c)(3)]. This will support a demonstration that reactions between the cement, formation fluids, and carbon dioxide will not lead to deterioration in the strength of the cement sheath or increases in the porosity and permeability that could result in the cement sheath becoming a conduit for carbon dioxide or carbon dioxide-rich fluids.

The chemical and mechanical properties of hydrated cement in contact with a carbon dioxide-rich environment should be considered. This is particularly relevant for Portland based cements. Owners or operators should demonstrate that the proposed cement sheath for their injection well will maintain integrity during the course of the project, including after injection ceases. This demonstration should take into account the following information gathered during site characterization and during well construction:

- Chemical analyses of fluids in the injection zone and, if available, the confining zone;
- Cement type and additives;
- Pressure, temperature, and pH in the injection zone and, if available, the confining zone;
- Chemical characteristics of the injectate, including impurities that may result in an especially low pH (e.g., sulfur dioxide); and
- Mineralogy of the injection and confining zones.

Data Collection and Analysis

To make a demonstration of compatibility, the owner or operator may conduct bench-top laboratory experiments and/or perform modeling or provide a detailed discussion of geochemistry based on available literature. Guidance and recommendations for these approaches are presented below.

Modeling may be performed to support the compatibility demonstration. Owners or operators should state assumptions used in modeling such as governing mechanisms (diffusion of carbon dioxide into cement, transport through microannuli), and assumption of local equilibrium vs. modeling of kinetics. Owners or operators should identify the aqueous and mineral components (e.g., carbonate minerals, jennite or tobermorite for calcium silicate hydrate) included in the modeling and identify the thermodynamic data set used. Modeling should also account for changing subsurface conditions as a result of injection over time. If the owner or operator chooses to pursue modeling as part of the demonstration, he or she may consider the approaches used in recent studies (e.g., Wigand et al., 2009; Huet et al., 2010).

Owners or operators may use **benchtop laboratory experiments** in a hydrothermal or flow-through apparatus to support their compatibility demonstration. Any such experiments should be conducted at downhole pressure and temperature conditions. Samples of cement used in experiments should be cured under conditions representative of downhole pressure and temperature conditions in order to replicate the mechanical properties of the cement sheath in the injection zone. Experimental fluids should be formulated to mimic formation fluid composition.

Experiments should be conducted over a sufficient time frame to permit measurement of the resulting mineralogical and mechanical properties. At the end of the experimental run, cement samples should be analyzed for mineralogy, texture, porosity, permeability, and strength; results should be compared with initial values. Examples of laboratory experiments performed for research purposes include Wigand et al. (2009) and Carroll et al. (2011).

Owners or operators may discuss with the UIC Program Director the acceptability of using a **literature-based discussion** for their demonstration. This approach may be viable for settings where the injectate will be free of impurities, such as sulfur dioxide that might cause extremely low pH, and if the proposed cement has additives known to reduce susceptibility to carbonic acid attack. Such a discussion should take into account both field and laboratory-based information and should also explain how the proposed cementing procedures will result in a high-quality sheath that will resist incursion of carbon dioxide-rich fluid along the well bore (i.e., no microannuli or channels in the cement).

Information to Submit

In submitting the cement compatibility demonstration, the owner or operator should describe the method selected for the demonstration and why it was chosen. For a literature-based discussion, all relevant literature and relevant data from site characterization (e.g., formation fluid chemistry) should be referenced.

If owners or operators use an experimental approach, EPA recommends that they provide:

- A thorough description of the experimental methods;
- Why the particular experimental technique was chosen;
- Conditions under which the cement sample was cured;
- The chemistry of the input solution and the carbon dioxide phase (i.e., impurities);
- Porosity, permeability, and density of the cement sample prior to experimentation;
- Plots of solution chemistry with time during the experiment;
- Properties of the cement sample at the end of the experiment and at any intermediate stages at which samples are taken; and
- A discussion of the results and implications for the long-term integrity of the cement.

If owners or operators select a modeling approach, they should provide the following:

- The model used;
- Input data in tabular form;
- Modeling parameters and data used (activity coefficient model, thermodynamic database, solid phases selected, reactions modeled, kinetics data, etc.);
- Results in tabular and graphical form;
- A thorough narrative interpreting the results and their applicability to the project; and
- A discussion of limitations and uncertainties associated with the modeling.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that the experimental conditions or modeling parameters are representative of the project, and that any reactions between the carbon dioxide and the cement or other well materials would not compromise the integrity of the well. See the *UIC Program Class VI Well Construction Guidance* for additional information on the compatibility of well materials and cements with carbon dioxide.

3.4. Demonstration of Storage Capacity

A demonstration of storage capacity can support predictions of the ability of the injection zone to receive and contain the anticipated total volume of carbon dioxide to be injected throughout the life of the GS project without endangering USDWs. It will support a demonstration that the site meets the requirements of 40 CFR 146.83(a)(1) that the injection zone or zones be of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream. This information should be consistent with the proposed operating parameters, site-specific information, and AoR delineation under 40 CFR 146.84.

3.4.1. Methods for Estimating Carbon Dioxide Storage Capacity

Carbon dioxide storage capacity depends on a combination of factors including multiphase flow processes, formation geometry and types of boundaries (e.g., open or closed boundaries, fault sealing), geologic parameters (e.g., porosity, permeability, compressibility) and their heterogeneity, and subsurface geochemistry (Doughty et al., 2001). Therefore, each type of geologic system chosen for storage (e.g., oil and gas reservoirs, saline formations, unmineable coal seams, and shale and basalt formations) may have different characteristics to consider while estimating storage capacity. In addition, project-specific factors also affect the storage capacity estimations, such as total volume, and chemical and physical characteristics of carbon dioxide to be injected; injection well configuration (e.g., number of wells and locations) and well bore integrity; operational parameters (e.g., pressure, injection rate); and other injection and production activities. EPA recommends that estimates of storage capacity, therefore, be accompanied by a clear statement regarding factors considered and the limitations of the assessment method used.

Methods for estimating carbon dioxide storage capacity can be divided into static and dynamic models (USDOE, 2008; NETL, 2010). The application of static and dynamic models for estimating carbon dioxide storage capacity is based on methods routinely used in the UIC Program and by industry and others for estimating petroleum reserves, ground water resources, and underground natural gas storage. The selection of suitable methods for estimating storage capacity needs to consider various combinations of physical and chemical trapping mechanisms and their effectiveness over geological time frames and scales (Bachu et al., 2007; IPCC, 2005). Brief discussions regarding static and dynamic modeling methods for estimating carbon dioxide storage are provided in Sections 3.4.2 and 3.4.3, respectively. Section 3.4.4 describes considerations for the application of storage capacity estimation methods.

3.4.2. Static Models

Static models are simplified mathematical expressions that can be used to estimate the quantity of carbon dioxide stored in a reservoir and are typically used prior to injection, although they can also be used for estimating storage capacity after injection commences. Static models include volumetric and compressibility models (USDOE, 2008). Volumetric models are applied to open reservoirs when it is assumed that formation fluids are freely displaced from the reservoir. These models use porosity, area, and thickness in a Monte Carlo simulation approach with various efficiency terms included to account for the fraction of accessible pore volume that will be occupied by the injected fluid (USDOE, 2008). Compressibility-based models are used to estimate carbon dioxide storage in closed reservoirs, which are separated laterally by low-permeability zones where the injected carbon dioxide is constrained by the compressibility of the formation's native fluid and rock matrix. The compressibility approach is generally used for fluids with nearly constant total compressibility and assumes a single-phase system; typical applications include single-phase oil reservoirs and confined saline formations.

Static models, typically applied to basin- or regional-scale assessments, can be used to quantify carbon dioxide storage estimates for oil and gas reservoirs, saline formations, and unmineable coal seams (Bachu et al., 2007; NETL, 2010). Standardized methodologies for estimating carbon dioxide storage capacity using static models have been adopted by the Carbon Sequestration Leadership Forum, and use of static methods has been proposed by DOE's Regional Carbon Sequestration Partnership Program. A comparison of methods proposed by the two groups can be found in Bachu (2008). Owners or operators should be aware of the limitations of any static model selected, including the model's limited ability to address factors that affect carbon dioxide storage capacity such as geologic heterogeneity, fault-sealing, well bore integrity, injectivity, formation geochemistry, the various trapping mechanisms, and the injection well configuration. While these models are employed more generally for basin- or regional-scale assessments, they also do not address issues related to far-field pressure buildup or native formation fluid (e.g., brine) displacement (Birkholzer and Zhou, 2009). Additional information on storage capacity estimation using static models is available in the Appendix.

3.4.3. Dynamic Models

Dynamic methods include decline curve analysis, material balance, and reservoir simulation (USDOE, 2008). Of these, reservoir simulation is the most advanced and the most resource-intensive option and may not be easily applicable to basin- or regional-scale assessments where the necessary data are limited. However, this approach is suitable for local- or site-scale assessments, such as a Class VI project, where site characterization data are available and numerical modeling is already employed for AoR delineation. Using this approach will allow the development of more realistic, site-specific storage estimates that account for site-specific factors (e.g., boundaries, formation heterogeneity, near- and far-field pressure buildup, formation fluid displacement, etc.) as well as project-specific factors (e.g., operational parameters, injection well configurations, well bore integrity, etc.). This approach can also be used to reduce uncertainty and refine estimates of storage capacity by integrating new field data and well testing information during operation.

Decline curve analysis, for which a specific injection rate-time relationship (e.g., exponential function) is assumed, can be used for estimating storage capacity; however, it can only be used for active injection operations (USDOE, 2008). This method is generally applicable to individual wells or entire fields as long as the injection rate and time data exhibit a trend that fits the assumed function. Similarly, the material balance approach is also more suitable for injection operations already taking place since it includes the cumulative carbon dioxide injection and the corresponding pore pressure at various times.

3.4.4. Application of Methods for Estimating Carbon Dioxide Storage Capacity

Storage capacity estimates needed to support a demonstration that the site meets the requirements of 40 CFR 146.83(a)(1) will initially be submitted along with the permit application, which also includes the required AoR delineation information under 40 CFR 146.84. The numerical modeling employed for delineating the AoR must be based on site characterization data and account for chemical and physical properties of all phases of the carbon dioxide injected [40 CFR 146.84(a)]. Therefore, EPA recommends performing dynamic storage capacity estimates, complemented by static methods as described below, in concert with development of the numerical modeling used for the AoR delineation. If another method is chosen by the owner or operator, the application used should account for the planned and proposed operational parameters and the site characterization data collected, and be consistent with the AoR delineation process.

In formulating an initial storage capacity estimate for site selection or screening activities, owners or operators may use static models in conjunction with available data on the project site. Additionally, static models can provide alternative assessments of storage capacity to confirm numerical modeling results if a reservoir simulation is chosen to determine and/or demonstrate the suitability of a site for a proposed project.

In depleted reservoirs that have been used for EOR, reservoir simulations may have been previously performed to predict reservoir behavior based on the amounts of carbon dioxide injected. In these cases, estimating storage capacity can be facilitated by continued use of reservoir modeling. In coalbed methane settings, the storage mechanism is relatively straightforward and may be done in a manner similar to reserves estimation (Bachu et al., 2007). A static model may be suitable for such settings, keeping in mind limitations in calculation of the storage efficiency factor; owners or operators are encouraged to discuss the suitability of such estimates with the UIC Program Director.

Estimation of storage capacity in deep saline formations will be more challenging than for depleted reservoirs or coalbed methane enhanced recovery settings because saline formations will involve several trapping mechanisms; in addition, fewer data may be available and existing data may be at a lower spatial resolution. Bachu et al. (2007) note that the storage capacity estimate needs to include the contributions from the various trapping mechanisms (structural/stratigraphic, solubility, residual, and mineral), and provide examples of using static model calculations for different trapping mechanisms. Numerical simulations can be used to explore this level of complexity at the site scale and are the most rigorous approach. However, the usefulness of reservoir simulation will be limited by the amount and quality of data available at the time the estimate is made. In some cases, static models may provide an adequate initial estimate; however, EPA recommends that they be refined using dynamic modeling when adequate data become available. Any uncertainties about which approach is suitable should be discussed with the UIC Program Director.

See the Appendix for additional discussion of data needs for storage capacity estimates. EPA also strongly encourages owners or operators to perform sensitivity analyses to estimate the effects of uncertainty in the input data for all storage capacity estimates.

After injection commences, the owner or operator should periodically update and refine the estimate of carbon dioxide storage capacity based on new field data and well testing information. EPA recommends the use of dynamic modeling for updating carbon dioxide storage capacity estimates. Periodic reevaluations of the storage capacity should be done in conjunction with reevaluations of the AoR. For example, estimates of carbon dioxide trapping mechanisms from reactive transport modeling will affect storage capacity estimates. Likewise, alterations in storage capacity estimates may lead to changes in operational parameters. Evaluations of storage capacity and operational parameters may especially need to be revisited in case of unexpectedly high pressure buildup within the injection formation or evidence of fluid displacement that may cause significant risk of endangerment to USDWs.

Information to Submit

In reporting storage capacity estimates, the owner or operator should submit:

- A description of the selected estimation method, including a discussion of its suitability for the type of formation;
- Tabulation of any input data used, along with estimates of uncertainty in those data;
- Results in tabular or graphic format;
- A discussion of the results, relating them to proposed operational parameters and the anticipated total volume of carbon dioxide to be injected and the duration of the project and any identified site-specific vulnerabilities (e.g., faults, fractures, etc.);
- A discussion of assumptions and limitations of the method used;
- A discussion of uncertainty based on the results of a sensitivity analysis; and
- A discussion of how the results are consistent with and/or supported by the AoR delineation modeling.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that the storage capacity estimates support the anticipated injection rate and operational period, and that the anticipated total amount of injected carbon dioxide will not exceed storage capacity. The owner or operator should also demonstrate through sensitivity analyses that conservative estimates have been used for setting the proposed injection rate and volumes. An example evaluation of carbon dioxide storage capacity has been described by Asghari et al. (2006).

3.5. Demonstration of Confining Zone Integrity

The owner or operator must demonstrate the ability of the confining zone to contain the carbon dioxide [40 CFR 146.83(a)(2)] and not allow migration of carbon dioxide, either through interconnected pore spaces across the thickness of the seal or through the confining zone along faults or fractures. In particular, analyses may be needed to ensure that existing non-transmissive faults will not become transmissive under anticipated injection and storage pressures.

A number of approaches may be used to demonstrate competence of the confining zone. The Class VI Rule does not specify which methods should be used; rather, the choices of analyses and the data needed will depend on site geology. The methods described here are applicable to sites with single confining zones or multiple confining zones, if characterization of such additional zones is required by the UIC Program Director, per 40 CFR 146.83(b).

Data Collection and Analysis

An assessment of confining zone integrity will involve a synthesis of several types of information gathered through the site characterization process. In general, the following types of data may be used when demonstrating confining zone integrity:

- **Lithologic and stratigraphic data**, e.g., on the depth, thickness, and mineralogy of the confining zone (see Sections 2.3.3 and 2.3.4);
- **Structural data**, e.g., on faults and fractures, including fault geometry, depth of origin and termination, and the amount of displacement along the fault, including determinations of whether slip is consistent or variable along the fault and where such variations occur (see Sections 2.3.2 and 4.2);
- **Data from core analysis**, e.g., the capillary pressure, rock strength, permeability, and porosity (see Section 4.2);
- **Field formation testing data**, e.g., in situ fluid pressures, the magnitudes of principal stresses, and temperature (see Section 4); and
- **Geophysical survey data**, e.g., seismic, gravity, magnetic, or other geophysical methods (see Section 2.3.10).

Furthermore, while not a direct measure of integrity, the ability of the confining zone to contain natural oil and gas accumulations may serve as an additional line of evidence. Considerations for demonstration of confining zone integrity are presented in Section 3.5. Section 3.5.3 provides additional considerations for projects that will operate under injection depth waivers.

3.5.1. Movement through the Confining Zone

Continuous confining zones lacking faults or fractures may still allow the transmission of carbon dioxide through interconnected pore spaces throughout the thickness of the seal. Movement across intact seals in a GS setting will likely be controlled primarily by capillary pressure and permeability:

- **Capillary pressure.** As a general rule, good seals will have capillary entry pressures between approximately 6 and 40 MPa (Duncan, 2009). EPA recommends that owners or operators verify that the capillary entry pressure is in excess of pressure increases expected from the buoyancy-driven accumulation of carbon dioxide. Computational modeling developed for AoR delineation can assist in evaluating whether predicted pressures will remain below the capillary entry pressure, but owners or operators should bear in mind that such a demonstration is constrained by the fact that capillary pressure measurements will only be available from limited point locations. Capillary pressure and related measurement techniques are discussed in Section 2.3.5.3; and
- **Permeability.** Once the fluid pressure exceeds the capillary pressure, fluid may flow through the layer at a rate controlled by the permeability and the fluid pressure (Duncan, 2009). A layer can make an effective seal even if the capillary entry pressure is low or if capillary entry pressure is exceeded, as long as the permeability is also low. Owners or operators should provide relative permeability-saturation-capillary pressure relationships derived from core analyses. They should discuss permeability of the confining zone in the context of other characteristics such as capillary pressure and thickness, and they may consider the performance of similar lithologies in other GS projects. Owners or operators may also consider numerical modeling to assess the potential effectiveness of the seal in inhibiting migration of carbon dioxide. See the Appendix for additional information on measurement of intrinsic permeability and relative permeability.

3.5.2. Transmission of Carbon Dioxide through Faults

A confining zone may be compromised if faults or fractures allow carbon dioxide movement across it. Faults can provide leakage pathways and fractures can be generated when capillary entry pressure and pore pressure exceed the rock strength. At that point, the layer will fracture before carbon dioxide enters into the pore spaces.

Characterizing the Sealing Potential of Existing Faults or Fractures

Faulted or fractured formations may seal carbon dioxide (Meckel, 2007), but EPA recommends that applicants verify confining zone integrity by characterizing the sealing potential of the formation. Any faults or fractures that intersect, originate, or terminate in the confining zone should be thoroughly characterized (i.e., dimensions, geometry, sealing properties) regardless of their size (Knipe et al., 2001; Meckel, 2007). Thorough characterization of these features is important because properties can be heterogeneous across the fault or fracture plane, complicating interpretation (Freeman et al., 1998). A fault or fracture may be sealing (non-transmissive) in some regions while remaining transmissive in others.

Owners or operators should also keep in mind that leakage can occur in complex seals composed of numerous variably permeable layers. For example, small faults and fractures that do not extend completely through the unit can connect permeable regions of the unit to form pathways for carbon dioxide migration (Ingram et al., 1997). These types of leakage pathways are likely to be more difficult to characterize because of their smaller scale.

EPA suggests several possible approaches to evaluate the likelihood of leakage occurring across existing faults or fractures, as follows:

- **Juxtaposition of units.** Faults are likely to be sealed against lateral movement of carbon dioxide across the fault if the fault juxtaposes conductive and non-conductive units on either side. An Allan chart can be used to determine which units contact each other along a fault surface (Knipe et al., 1998);
- **Leakage along faults.** The risk of leakage along a fault will be lower if sediments with a high capillary pressure and low permeability are found along or incorporated into the fault zone. These sediments will prevent migration of carbon dioxide along the fault for the same reasons they can prevent migration upward when present as a seal. Such materials can occur along the faults as a result of catalysis, diagenetic sealing, or by entrainment during fault movement. Owners or operators may use information from outcrops or cores that intersect the fault to evaluate whether such sediments occur in the fault zone;
- **Catalysis.** Breakdown of materials along the fault due to physical abrasion during fault slip can produce fine material that tends to have smaller pore throats and, correspondingly, high capillary pressure. Catalysis can reduce the permeability of high-porosity sandstones up to four orders of magnitude with only a few centimeters of slip and lead to sealing behavior along the fault (Yielding et al., 1997). Owners or operators may evaluate the degree of catalysis by examining hand samples, cores, or thin sections of samples taken from the fault zone. After evaluation, hand samples may be subjected to capillary pressure tests or other laboratory tests to quantify the effect of catalysis on pore size;
- **Diagenetic sealing.** Determining the amount of diagenetic sealing of a fault or fracture due to authigenic calcite or silicates requires the direct examination of core samples from the fault or fracture zone in the laboratory. In some cases, samples taken from nearby faults or outcrops may be used to infer the amount of diagenetic sealing on buried faults or fractures, provided that the faults or fractures examined originated in the same time period and that evidence at various scales (e.g., thin section, hand sample, outcrop) indicate that diagenetic behavior is similar throughout the unit;
- **Calculation of shale gouge ratio (SGR).** Materials from hanging- and footwalls in shale and other clay-rich formations can be incorporated along a fault, producing shale gouge. This fine-grained material helps to retard the flow of fluids along the fault. The amount of shale entrained by the fault from the shale/siltstone units the fault intersects can be estimated using the SGR (Freeman et al., 1998). This method works best for shale/sandstone/siltstone sequences. See the Appendix for additional information on calculation and interpretation of the SGR. Calculation of the SGR and other shale-entrainment methods requires accurate knowledge of lithology (specifically clay/phyllosilicate content) and thickness in the area of the fault. This level of information may require new boreholes, seismic surveys, other geophysical surveys, and/or a refined analysis of fault geometry and extent. EPA encourages owners or operators to determine the SGR where it is feasible and appropriate; and
- **Pressure compartmentalization.** If a fault compartmentalizes regions of different subsurface pressure, it may be sealing (Huffman, 2002). This method requires both subsurface mapping of all faults within the area of interest and pore pressure

measurements. Pressure measurements can be taken directly from wells on both sides of the fault (Doughty and Karasaki, 2004), or indirect pore pressure data may be generated by transforming seismic velocity data into pore pressure (see Section 2.3.10 and the Appendix). An example figure is provided in the Appendix.

The owner or operator should be aware that use of seismic pore pressure estimates is still under development and can introduce errors, especially in subsurface environments that have not undergone significant subsurface exploration. Gathering sufficient subsurface pressure data by wells to use the pressure compartmentalization method may be labor intensive, and, although a pressure difference across a fault indicates sealing behavior, the lack of a pressure difference does not definitively indicate a transmissive fault.

3.5.3. Special Considerations for Characterizing Lower Confining Zones

An owner or operator applying for an injection depth waiver must demonstrate the integrity of both the upper and the lower confining zones [40 CFR 146.95(a)(2)]. The basic methods for evaluating seal integrity remain the same whether the confining zone is above or below the injection zone. Estimates of thickness, permeability, fracture pressure, capillary pressure, and other parameters are recommended, as well as an understanding of whether the zone contains interbedded units of higher permeability. The owner or operator will also need to demonstrate that the confining zones are free of transmissive faults and fractures [40 CFR 146.95(a)(2)].

One important difference to consider between confining zones above and below the injection zone is that the upper confining zone will likely contact free-phase carbon dioxide prior to its dissolution while the lower confining zone may or may not contact free-phase carbon dioxide. However, both the upper and lower confining zones will be in contact with brine and may eventually be in contact with carbon dioxide-saturated brine. While capillary entry pressure is not relevant in the case of brine contacting a confining zone already saturated with brine, the capillary entry pressure of free-phase carbon dioxide in the lower confining zone should be determined and considered. See the *UIC Program Class VI Well Injection Depth Waivers Guidance* for additional information on applying for injection depth waivers.

Information to Submit

EPA encourages owners or operators to submit a discussion of confining zone integrity. The owner or operator should reference all relevant information from the site characterization and should provide a narrative discussing all lines of evidence used to support the demonstration. Details should be shown for any calculations performed (e.g., SGR), and images that support the demonstration should be annotated to illustrate relevant features. Not all types of analyses presented above may be needed, but the information presented should collectively indicate that the confining unit meets the requirements at 40 CFR 146.83. Any limitations in the data or analysis should be noted.

Because the parameters used to assess confining zone integrity are calculated from existing data, the reliability of the final measurement depends upon the quality of the input data, and errors will be propagated through any calculations done in support of this analysis. The owner or operator should discuss any potential errors and how they may affect the evaluation of confining zone integrity.

Because fault properties may vary spatially along the fault, resulting in variability of sealing capacity, the owner or operator should communicate any uncertainties in the data and be cognizant of the need for additional analyses to represent any spatial heterogeneity.

3.6. Considerations for Secondary Confinement

The Class VI Rule, at 40 CFR 146.83(b), provides the UIC Program Director with discretion to require the owner or operator to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation. This demonstration is needed to facilitate consideration of GS sites where the owner or operator or the UIC Program Director determines that an additional barrier to fluid movement is appropriate based on site-specific data.

These additional confining zones will not be needed in all circumstances, and the UIC Program Director would exercise their discretion to require characterization of secondary confinement if, for example, the first impermeable zone immediately above the injection zone can provide some confinement but may not demonstrate all of the properties needed to ensure that the carbon dioxide will not migrate. Characterization of a secondary confining zone may be needed if:

- The primary confining zone does not exhibit sufficient strength to allow injection at the proposed pressures;
- Known or suspected faults or fractures transect the primary confining zone and would interfere with containment of carbon dioxide;
- The primary confining zone is not sufficiently extensive to cover the entire maximum extent of the carbon dioxide plume and pressure front or it is not sufficiently thick and homogeneous over the entire area; or
- There is insufficient information or conflicting data about the primary confining zone.

Data Collection and Analysis

If the UIC Program Director requires information about a secondary confining zone, the owner or operator will need to demonstrate how the two layers would contain and prevent upward movement of the carbon dioxide. This demonstration should address how the two confining zones together meet all the requirements for confinement at 40 CFR 146.83(a)(2). Specifically, they should be free of faults that are transmissive throughout both confining zones, be of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids, and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures. The owner or operator may also need to characterize the intervening zones between the primary and secondary confining zones to demonstrate that they allow for pressure dissipation and provide additional opportunities for monitoring or remediation.

Characterizing the secondary confining zone and any intermediate zones will involve the same methods that are used to characterize the primary confining zone. Some types of data, such as well logs or cross sections, will probably contain information about all subsurface formations, and the owner or operator would need to highlight information relevant to the additional confining zone and intervening layers.

If existing data or cores are used, the owner or operator should verify that they include coverage of the secondary confining layer and, ideally, any intervening units. If adequate data and/or samples are not available, additional sampling or analysis may be needed. If core samples are taken during drilling of a stratigraphic well, the owner or operator should ensure that the cores include representative samples from the primary and secondary confining zone, as well as any intervening layers. Owners or operators may need to obtain core analyses for samples from the secondary confining unit (e.g., porosity, permeability, capillary pressure, mineralogy, strength). Any relevant features on seismic or other geophysical images that help define the thickness and areal extent of the confining zone and characterize faults should be highlighted. In some cases, the owner or operator may need to establish the fracture pressure or fault sealing capabilities in the secondary confining unit.

Information on the potential for pressure dissipation within the intervening layers may come from AoR modeling that includes information about both confining zones and the intervening formations. If additional ground water quality monitoring or direct monitoring for carbon dioxide or pressure measurements in these zones is warranted, the owner or operator should demonstrate how such monitoring enhances the Testing and Monitoring Plan.

Information to Submit

The owner or operator is encouraged to discuss with the UIC Program Director specific needs related to characterizing additional confining zones, including how the primary confining zone is deficient. This will establish the level of data collection and analysis that may be needed to demonstrate that the system of subsurface formations is sufficient to confine the carbon dioxide and protect USDWs from endangerment.

Based on the discussions, additional data collected, and additional analysis of the secondary confining zone, the owner or operator should submit to the UIC Program Director a description of the primary and secondary confining zones and the intervening layers, and how they will impede vertical fluid movement, allow for pressure dissipation, and provide additional sites for monitoring, mitigation, and remediation.

3.7. Reporting Process

The Class VI Rule requires owners or operators to submit site characterization data collected pursuant to 40 CFR 146.82(a) and (c) with the permit application or prior to receiving authorization to begin injection, respectively (see the preceding sections of this document for specific recommendations on the types of information to submit). These data must be retained throughout the life of the GS project and for 10 years following site closure [40 CFR 146.91(f)(1)].

Under the Class VI Rule, regardless of whether a state has primary enforcement responsibility, owners or operators are required to submit site characterization data to EPA in an electronic format approved by EPA [40 CFR 146.91(e)]. The data and supporting documents may be submitted as PDF files, including charts, graphs, and tabular data. EPA also recommends that raw data be submitted, in separate files (e.g., LAS, Excel). Additionally, EPA recommends that maps be submitted in a GIS-compatible format, to further assist a more detailed and flexible review process by the UIC Program Director. For additional information on complying with the reporting requirements related to submitting site characterization data, please see the *UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators.*

4. Activities Performed Prior to Operation of a Class VI Well

Prior to commencing injection, owners or operators must provide extensive geologic and hydrogeologic data collected during the construction of a Class VI well to demonstrate to the UIC Program Director that the injection and confining zones are suitable for receiving and containing injected fluids [40 CFR 146.82(c)]. This section provides guidance on the formation and well testing and logging activities that the owner or operator must conduct to generate the information and data required to receive authorization to inject at a Class VI well.

The testing and logging activities described here provide the information and data that will be considered by the UIC Program Director in authorizing Class VI operation as identified in 40 CFR 146.82(c) and the formation testing requirements at 40 CFR 146.87. (The *UIC Program Class VI Well Construction Guidance* provides information on how owners or operators can meet the injection well testing requirements of 40 CFR 146.87.)

For new Class VI wells, these testing and logging activities are undertaken during and after drilling and construction of the new injection well. For Class VI wells to be transitioned from other classes of injection wells (or pre-existing monitoring, stratigraphic test, or production wells), the testing and logging information can be provided from previous and ongoing testing and monitoring of the formation and from well tests and logs conducted during the previous use of the well.

The activities described in this section include formation testing/logging, core sampling and analysis, and hydrogeologic testing to determine the physical and chemical characteristics of the injection and confining zones. Importantly, these post-well construction/pre-operational testing and logging data will provide updates to and can be synthesized with related injection and confining formation data obtained during the GS site characterization and submitted earlier as part of the Class VI permit application. Where appropriate, this section references related topics in Section 2 of this guidance.

Each section below describes the Class VI Rule requirements that relate to specific testing/logging activities and identifies the use or relevance of the information to be provided. Brief technical descriptions are provided in the Appendix for testing and logging methods and how required information and data can be generated or obtained. Where appropriate, subsections below also provide recommendations and special considerations for obtaining and interpreting data and note particular aspects of the formation and well characterization process that might warrant discussions with the UIC Program Director.

4.1. Well Logging

During the drilling and construction of a Class VI injection well, the owner or operator must run logs, conduct surveys, and perform tests when appropriate to determine or verify the depth, thickness, porosity, permeability, lithology, and salinity of any formation fluids in all relevant geologic formations [40 CFR 146.87].

These well logging activities supplement data on geologic and hydrogeologic properties of relevant subsurface formations collected during initial site characterization and are used to support building a conceptual understanding of the site, conducting the AoR determination, and designing the GS project. Performing a variety of logs provides complementary information on subsurface properties as well as taking advantage of the different levels of vertical resolution of the log types.

Data Collection and Analysis

At a minimum, well logs must include resistivity, spontaneous potential, gamma ray, porosity, fracture finder logs, and any other logs the UIC Program Director requires based on the geology of the site [40 CFR 146.87(a)(2) and (3)]. These logs must be conducted before installation of the surface casing [40 CFR 146.87(a)(2)(i)] *and* before installation of the long-string casing [40 CFR 146.87(a)(3)(i)]. Any alternative methods that provide equivalent or better information must be approved by the UIC Program Director prior to implementation [40 CFR 146.87(a)(5)]. These types of logs are described in the Appendix; for further information on geophysical logging and analysis, see Asquith and Krygowski (2004), Telford et al. (1990), and NETL (2009).

Information to Submit

The owner or operator must submit to the UIC Program Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of these logs [40 CFR 146.87(a)]. This report must be provided in an electronic format and should include:

- The date and time of each test, the date of well bore completion, and the date of installation of all casings and cements;
- Chart results of each log and any supplemental data;
- The name of the logging company and log analyst and information on their qualifications;
- Interpretation of the well logs by the log analyst, including any assumptions, determination of porosity, permeability, lithology, thickness, depth, and formation fluid salinity of relevant geologic formations; and
- Any changes in interpretation of site stratigraphy based on formation testing logs.

To support the UIC Program Director's evaluation of the logging results, EPA recommends that the owner or operator demonstrate that the collected information is consistent with other available site characterization data in the permit application and that the data support other assessments of stratigraphy and formation properties. The owner or operator should demonstrate that the logs were adequately performed and properly characterize all formations, and that logging tests were conducted by a knowledgeable log analyst. The UIC Program Director may compare the results of formation testing logs from different wells in the vicinity to interpret local stratigraphy and verify the depths and properties of the proposed injection and confining zones.

Where information gathered via the logs diverges from other data or supports different conclusions about the subsurface, the owner or operator should discuss in the report, and with the

UIC Program Director, the implications for any of the planned operational procedures, the AoR determination, or the GS project plans.

4.2. Core Analyses

The Class VI Rule [40 CFR 146.87(b)] requires the owner or operator to take whole cores or sidewall cores of the injection and confining zones and formation fluid samples from the injection zone(s) and to submit to the UIC Program Director a detailed report prepared by a log analyst.

Core samples provide information to support stratigraphic correlation, interpretation of depositional environments, and wireline log calibration. Information from cores will be used to refine site characterization data submitted pursuant to 40 CFR 146.82(a). Core samples may also have been taken prior to well construction if a stratigraphic well was drilled during initial site characterization.

Data Collection and Analysis

Core Sampling

Decisions about the type of coring to perform will ultimately depend upon logistics and the type of lithology to be cored. Detailed information on the various coring methods is available in Whitebay (1992). Proper drilling methods should be practiced to maintain zonal isolation when penetrating the confining zone or any over- or under-pressured zones.

Core samples must be taken from the injection and confining zones [40 CFR 146.87(b)]. Owners or operators may also consider analyzing samples from the first permeable formation overlying the confining zone or from other permeable formations and confining zones farther up in the stratigraphic column. The lower confining zone should be included if the owner or operator has been granted an injection depth waiver (see the *UIC Program Class VI Well Injection Depth Waivers Guidance* for additional information on the injection depth waiver application process).

The optimal number of samples to analyze will vary by site, but representative samples should be chosen from cores and core sections with different lithologies and characteristics (e.g., texture, grain size). Heterogeneous formations would warrant more closely spaced core samples than uniform formations. For heterogeneous formations with many fractures or solution features, it may be preferable to examine the complete length of full-diameter core in the interval being tested. Owners or operators may have also used a geostatistical approach to model the distribution of permeability and porosity in the injection and confining zone(s); selection of core samples during drilling and construction of the Class VI well should be planned to further refine such estimates.

Core Logging and Analysis

Core logs should include descriptions or indications of: lithology, thickness, grain size, sedimentary structures, diagenetic features, contacts, textural maturity, oil staining, fracturing, and porosity. Laboratory analysis of cores should include petrology and mineralogy; petrophysical properties; and geomechanical properties (see Sections 2.3.4 through 2.3.6). Owners or operators may consider special core analysis (SCAL) to obtain an in-depth suite of tests for parameters relevant to GS, such as relative permeability, capillary pressure, fluid compatibility, wettability, and pore volume compressibility.

Information to Submit

Owners or operators must submit to the UIC Program Director a report prepared by a log analyst [40 CFR 146.87(b)]. Owners or operators should review the report prior to submission to ensure that it is complete and includes information on methods, notes on QA samples and calibration of instrumentation as appropriate, results in tabular and/or graphic form, and photographs as appropriate. Where information from the core analysis diverges from other data or supports different conclusions about the subsurface, the owner or operator should discuss in the report, and with the UIC Program Director, the implications for any of the planned operational procedures, the AoR determination, or the GS project plans.

4.3. Characterization of Injection Formation Fluid Chemical and Physical Properties and Downhole Conditions

The Class VI Rule requires the sampling and characterization of the chemical and physical properties of the formation fluids in the injection zone [40 CFR 146.82(a)(8) and 146.87(b)] as well as recording of the fluid temperature, pH, SC, reservoir pressure, and static fluid level [40 CFR 146.87(c)]. Fluid sampling and recording of downhole pressure, temperature, SC, and pH provides information to support a determination of the compatibility of the injectate with the formation fluids [40 CFR 146.82(c)(3)].

Data Collection and Analysis

Information on downhole pressure, temperature, pH, and SC can be obtained before completion using formation testing tools. Such tools may also record other parameters such as fluid density and fluid carbon dioxide. Alternatively, downhole conditions may be recorded after completion using wireline tools.

Fluid sampling can be done before well completion using wireline sampling devices, or after well completion. If sampling is performed before completion, the well bore should be cleaned of drilling mud as much as possible before the sample is taken (Nagarajan et al., 2007). After well completion, samples can be collected downhole using devices such as a flow-through device (see the *UIC Program Class VI Well Testing and Monitoring Guidance*), or at the surface by pumping the fluids for collection. Analyses generally include major anions and cations, pH, temperature, pressure, alkalinity, TOC, and total inorganic carbon (see Section 2.3.9).

<u>Information to Submit</u>

To meet the requirements of 40 CFR 146.82(a)(8) and 146.87(b), the owner or operator should submit the following information to the UIC Program Director:

- Type of sampling equipment used and field procedures (e.g., sample preservation);
- If the sample was pumped, flow rate, type of pump, and location of the pump, and geochemical modeling results indicating the likely geochemical makeup of the fluids at downhole conditions;
- Data for field measurements (pH, SC, temperature, pressure);
- Laboratory results, including QA samples (e.g., blanks, duplicates, matrix spikes); and
- Notes on any anomalous data.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that they used proper field techniques to obtain samples. Where information gathered via formation testing diverges from other data or supports different conclusions about the injection and confining zones, the owner or operator should discuss with the UIC Program Director, and in the report, the implications for any of the planned operational procedures, the AoR determination, or the GS project plans.

4.4. Fracture Pressure of the Injection and Confining Zones

Owners or operators must determine or calculate the fracture pressure of the injection and confining zones [40 CFR 146.87(d)(1)]. This information, in conjunction with predictions of pore pressures within the injection zone, is used to support the determination of an appropriate injection pressure to ensure that injection will not initiate or propagate fractures in the confining zone [40 CFR 146.83(a)(2)]. In addition, this information can be used to confirm or refine the preliminary site characterization information described in Section 2. Where the owner or operator has received an injection depth waiver, they should provide information on the fracture pressure of the lower confining zone(s) to support the determination of injection pressures that do not compromise confinement below the injection zone.

In addition, owners or operators may be asked by the UIC Program Director to determine or calculate other physical and chemical characteristics of the injection and confining zone(s) [40 CFR 146.87(d)(2)]. Any such request will be site-specific and would likely involve gathering data to augment other information gathered during the site characterization process, address any data anomalies or inconsistencies, support the development of the AoR delineation model, or support setting of permit conditions (e.g., operational limits).

<u>Data Collection and Analysis</u>

The step rate test is a common method for determining the fracture pressure of a formation (see the Appendix and USEPA, 1999 for additional detail). EPA recommends the use of downhole pressure gauges during the test. If a surface gauge is used, the reading needs to be corrected to obtain the downhole pressure and the correction factor will need to account for friction. For wells with depths greater than 3,000 feet, the uncertainty in the friction correction may introduce too much error to allow for an accurate reading (McAleese, 2000). EPA recommends using two pressure gauges to ensure that there is a backup if one gauge fails. Additionally, the flow meter should be calibrated prior to the test (USEPA, 1999).

Information to Submit

For the UIC Program Director to appropriately evaluate the fracture pressure calculation, as required at 40 CFR 146.87(d)(1), EPA recommends that the owner or operator submit the following information:

- Type and location of the pressure gauge;
- Type of flow meter and calibration records;
- Raw pressure and flow data;
- Plot of flow rate versus pressure data; and
- Discussion of any anomalous data.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that proper test conditions were obtained and that the proposed operating pressure is appropriate based on the information gathered and the predicted (modeled) pore pressures throughout the injection zone. The owner or operator should also demonstrate that proper correction factors were used if the gauges were not deployed at the bottom of the well bore and that a constant injection rate was used at each step period.

The owner or operator should also discuss how the calculated fracture pressure compares with data from core tests or other wells in the area. Where this information is not consistent with existing data or supports different conclusions about the subsurface formations, the owner or operator should discuss in the report, and with the UIC Program Director, the implications for any of the planned operational procedures (e.g., injection pressure).

Data from the step rate test may also be helpful in designing well stimulation programs. Step rate tests can be carried out in conjunction with hydrogeologic testing described in Section 4.5 in order to determine other reservoir properties such as transmissibility.

4.5. Hydrogeologic Testing

The Class VI Rule requires hydrogeologic testing of the injection well before injection operations begin. A pressure fall-off test and either a pump test or injectivity test [40 CFR 146.87(e)(1)–(3)] must be performed. These tests are designed to verify information on the injectivity of the injection zone to support the setting of permit limits for carbon dioxide injection rates and volumes. Injectivity depends on parameters such as porosity, permeability, and connectivity. Many of these parameters will have been measured during the initial site characterization. Hydrogeologic testing can verify these parameters and can also help determine any local reduction in permeability near the well bore caused by the well construction process, often referred to as the skin factor. Hydrogeologic testing can also be used to determine if a stimulation program is necessary and aid in the design of such a program. Data from hydrogeologic testing may also be useful in verifying the computational model for AoR determination.

4.5.1. Pressure Fall-Off Tests

Pressure fall-off tests are conducted on a well to verify several hydrogeologic parameters: the transmissibility of the injection zone, the static injection zone pressure, and the skin factor. Pressure fall-off tests can also indicate if there are faults and fractures near the well bore.

Data Collection and Analysis

EPA recommends the use of downhole gauges with surface displays for fall-off tests. The surface readout allows real time reading of the pressure and allows any anomalies to be noted and potentially corrected while the test is being conducted rather than during data analysis. Using two pressure gauges will provide a backup in case one fails and will provide two data sets which can be used to verify the accuracy of the test.

The appropriate injection and shut-in periods are determined based on site-specific parameters and the desired area for which data will be gathered. It is important that the flow rate during injection is constant and that the test is conducted over a sufficient period of time so that the pressure effects seen are not caused by the well bore but reflect the reservoir conditions. If the pressure fall-off test is to be used to examine reservoir features such as faults, non-homogenous areas, or other wells, the time should be long enough to allow the pressure effects from those areas to be seen. EPA Region 6 has published a guidance entitled “The Nuts and Bolts of Falloff Testing” (USEPA, 2003) that provides guidance on determining the appropriate injection and fall-off times, along with many other technical details.

Information to Submit

For the UIC Program Director to appropriately evaluate the fall-off test, EPA recommends that the owner or operator submit the following information:

- Raw pressure data;
- Flow data from the injection portion of the test;
- Test parameters (injection time, shut-in time, fluid viscosity, temperature, well bore diameter, pressure gauge type and location);
- Semi-log plots used for data analysis;
- Parameters calculated from the analysis; and
- Discussion of the results, including data quality and any anomalous values.

If the fall-off test data were used to verify computational model results, the owner or operator may also want to reference those results.

To support the UIC Program Director’s evaluation of the data, EPA recommends that the owner or operator provide sufficient information to demonstrate the validity and results of the test. For example, the owner or operator should demonstrate that pressure gauge data accurately capture the full range of test data and that the gauge was either properly placed to measure downhole pressure or appropriate corrections were made to calculate downhole pressure. The owner or operator should also demonstrate that a steady rate was held before the shut-in portion of the test was begun and that the time frame of the test was sufficiently long. The owner or operator should demonstrate that the semi-log plots were linear and explain any non-linearities against other data submitted for the site characterization.

EPA recommends that any interpretation of anomalies be corroborated with other data. For example, if an anomaly is proposed to have been caused by a fault, then the owner or operator should review and provide information from geologic maps and seismic data to determine if faults are documented in the area indicated by the pressure transient analysis.

Finally, the owner or operator should demonstrate that the results of the analysis are consistent with other site data. For example, transmissivity values calculated from the fall-off test may be compared to permeability values determined from cores. Where the information diverges from other data or supports different conclusions about the subsurface, the owner or operator should discuss the implications for any of the planned operational procedures, the AoR determination, or the GS project plans.

4.5.2. Injectivity and Pump Tests

Injectivity and pump tests are used in a manner similar to pressure fall-off tests to determine the transmissibility of the reservoir, the skin factor, and to identify nearby faults or fractures. The tests are subject to less interference from the well bore than pressure fall-off tests, but they are subject to more noise in the pressure data from the flowing fluid. Obtaining data from both a fall-off test and an injectivity or pump test allows verification of data, because, in some cases, more than one factor can yield similar pressure response curves.

<u>Data Collection and Analysis</u>

Injectivity testing involves pumping carbon dioxide into the well at a constant rate and recording the pressure response in the well. A pump test is similar to an injectivity test, but fluid is pumped from the well instead of injected. Either test can be used to fulfill the requirement at 40 CFR 146.87(e), and they should yield the same results. Injectivity tests are more commonly used in injection well applications. As with fall-off tests, placing the pressure gauge downhole reduces inaccuracies that are caused by friction loss in the well bore. Generally, with wells over 3,000 feet deep, downhole pressure gauges should be used (McAleese, 2000). Dual pressure gauges are also recommended to ensure that a backup gauge is available.

The rate of injection on an injectivity test should be low enough that the fracture pressure of the formation is not exceeded. The injection rate should be held constant long enough that radial flow is established and there are no near-well bore pressure effects. Variable flow rates or too short of an injection period may lead to poor test results.

Several variations on injectivity testing may be performed. A multi-rate injection test uses two or more injection rates to produce more data for a more complete analysis. Each injection rate is held long enough to obtain radial flow. In interference tests, fluid is injected into one well and the pressure is measured at another well. The interference test can yield information on the porosity and compressibility of the formation between the two wells. If planned properly, a pressure fall-off test can also be conducted following an injectivity test.

Pressure data from each of these tests are analyzed in the same way, using the same types of plots as those used for pressure fall-off tests. If the semi-log plots are not linear, this is likely due to errors in the assumptions underlying plot construction. Such errors could include non-constant injection rates, non-homogenous reservoir properties, interfering wells, or faults.

Information to Submit

Data submitted for injectivity or pump tests would be similar to data for a pressure fall-off test and should include:

- Raw pressure data;
- Flow data including rates and times;
- Test parameters (injection time, fluid viscosity, temperature, well bore diameter, pressure gauge type and location);
- Semi-log plots used for data analysis;
- Parameters calculated from the analysis; and
- A discussion of the results, including data quality and any anomalous values.

To support the UIC Program Director's evaluation of the data, EPA recommends that the owner or operator demonstrate that the test results are valid and verified, and that the data are consistent with other collected data. For example, the owner or operator should demonstrate that pressure gauge data accurately capture the entire range of injection pressures used. The owner or operator should also demonstrate that gauges were properly located to provide accurate bottomhole readings and/or that surface pressure readings were properly corrected to obtain bottomhole pressure.

The owner or operator should demonstrate that flow data and flow meters were calibrated and that a constant flow rate was maintained. The owner or operator should show that semi-log plots are linear and explain any anomalies, comparing data as necessary to other information collected during site characterization to aid in interpretation. Any deviations from linear behavior should be analyzed and a cause determined and documented. Because an anomaly may be caused by more than one type of phenomenon, any interpretations of anomalies should be verified using independent data. Where information from injectivity or pump tests diverges from other data or supports different conclusions about the subsurface, the owner or operator should discuss the implications for any of the planned operational procedures, the AoR determination, or the GS project plans. If the injectivity or pump test data were used to verify computational model results, the owner or operator may also want to reference those results.

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Appendix: Available Technologies and Methods for Conducting Required Site Characterization Activities

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Introduction

This Appendix provides background information on some of the activities that will be performed as part of site characterization for a GS project that meets the requirements of 40 CFR 146.82 and 40 CFR 146.87. The *UIC Program Class VI Well Site Characterization Guidance* assumes that owners or operators are familiar with many of the available techniques used in assessing proposed GS sites, and it focuses on how these techniques should be applied to meeting the Class VI Rule requirements. This Appendix presents additional information, including examples of the application of various techniques in GS or other scenarios, on certain activities that reviewers of the draft guidance suggested was too detailed for the guidance document. It also refers the reader to additional sources of published information that are publically available.

This Appendix includes the following sections:

- A1, Information to Support Development of Maps and Cross Sections of the Area of Review, Determination of Formation Thickness, Illustration of Structural Geology, and Facies Analysis, which augments Sections 2.3.1 and 2.3.3 of the guidance;
- A2, Information to Support Petrologic and Mineralogic Analysis, which supports Section 2.3.4 of the guidance;
- A3, Information to Support Submittal of Data on Porosity, Permeability, and Capillary Pressure of the Injection and Confining Zones, which supplements the information in Section 2.3.5 of the guidance;
- A4, Information to Support Geomechanical Characterization of the Confining Zone, which supports Section 2.3.6 of the guidance;
- A5, Information to Support Fault Stability Analysis and Analysis of Confining Zone Integrity, which provides additional information related to Sections 2.3.2 and 3.5 of the guidance;
- A6, Information to Support Geophysical Characterization, which provides additional information related to Section 2.3.10 of the guidance;
- A7, Information to Support Demonstration of Storage Capacity, which supplements Section 3.4 of the guidance; and
- A8, Information to Support Pre-Injection Logging and Testing, which relates to the information in Section 4.1 of the guidance.

A1. Information to Support Development of Maps and Cross Sections of the Area of Review, Determination of Formation Thickness, Illustration of Structural Geology, and Facies Analysis

To support owners or operators as they compile and/or prepare maps and cross sections of the AoR, as required by the Class VI Rule at 40 CFR 146.82(a)(3)(i), the sections below provide background information on stratigraphic cross sections, structural cross sections, and dipmeter logs. This information also supports determination of formation thickness [40 CFR 146.82(a)(3)(iii)] and local structural geology [40 CFR 146.82(a)(3)(vi)]. Information is also provided on facies analysis; a description of facies changes is required at 40 CFR 146.82(a)(3)(iii), and owners or operators may elect to do a more thorough facies analysis to help in developing the site conceptual model. For additional information and recommendations regarding this information, please see Sections 2.3.1 and 3.1 of the guidance.

Stratigraphic Cross Sections

Stratigraphic cross sections show characteristics of correlatable stratigraphic units relative to a chosen geologic layer, or datum. Cross sections can rely on and incorporate data from a variety of sources, including logs, seismic data, cores, and cuttings. Figure A-1 shows an example of a schematic stratigraphic cross section that also displays log data.

The choice of a datum (the level or reference horizon) is a key part of developing a stratigraphic cross section. By displaying geologic units relative to the datum, the stratigraphic cross section may illustrate geologic relationships as they existed at a previous time (i.e., prior to deformation). In many cases, an unconformity (such as a buried erosion surface) is used as a datum because unconformities often represent relatively uniform time horizons (Boak, 1992).

Stratigraphic cross sections may be produced with various orientations relative to structural features. Sections oriented perpendicular to the depositional strike show facies changes toward or away from the basin margin, while sections oriented parallel to the depositional strike show lateral variations of particular units or sequences (Boak, 1992; Evenick, 2008). Another common orientation is perpendicular to a fold axis or major fault (Groshong, 2006). Furthermore, while cross sections are normally presented perpendicular to the ground surface, only cross sections oriented perpendicular to the dip of the units will show the true bedding thickness (Groshong, 2006).

Cross sections can be checked for accuracy by restoring deformed strata to an original, undeformed state, where there are no gaps or overlaps between sedimentary layers. This technique may not be possible for complexly deformed areas and requires simplifying assumptions (such as consistent thickness) about the original depositional characteristics of the layers. In addition, this technique is not applicable to non-homogenous strata such as salt domes and reefs (Evenick, 2008).

Cross sections can be anchored or projected (Evenick, 2008). Anchored cross sections have direct well control; they are either pinned (have at least one well directly on the surface trace of the cross section) or tied (the trace follows a line from well to well). While tied cross sections have the advantage of direct data, they often enhance out-of-plane features and distort the thickness and other properties of subsurface layers (Evenick, 2008).

Projected cross sections have no direct well control. Projected cross sections may be bounded or synthetic. Bounded cross sections have data projected from nearby wells, and synthetic sections are not based on direct data. Projection of data onto the trace should be done carefully to avoid introducing error. Common methods include along dip, with structural contours, and within dip domains (groups of dips). See Groshong (2006) for more information on projected cross sections.

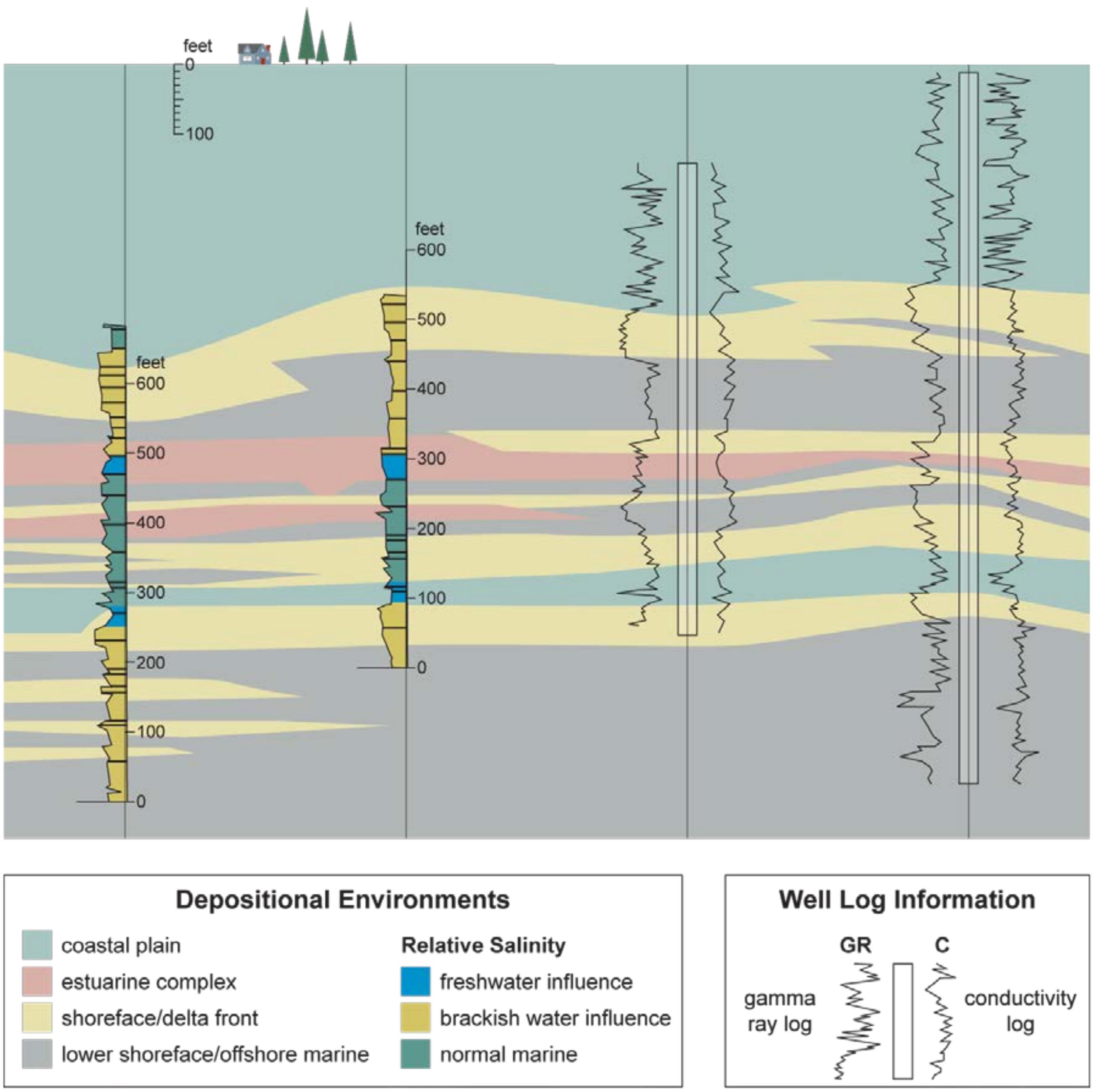


Figure A-1: Interpreted Cross Section.
Constructed from well log data. Distance scale is irregular to make the cross section more compact. Gamma ray logs are displayed to the left of the well, and conductivity is displayed to the right. From: Kirschbaum and Hettinger (2004).

Structural Cross Sections

Structural cross sections illustrate the subsurface relationships and structural features of rock units. Cross sections are generally most useful when oriented perpendicular to major structural trends, although bends in the section can be used to show variable structural trends or other features (Boak, 1992). Additional smaller cross sections can be included to illustrate specific features such as faults. Structural cross sections may reference attached stratigraphic cross sections if correlations are difficult. Figure A-2 shows an example of a structural cross section.

Stratigraphic and structural cross sections are developed using similar methods. For a structural cross section, the datum is generally sea level, and units are drawn above or below that elevation according to their present positions (Boak, 1992). Unlike stratigraphic cross sections, structural cross sections are generally drawn with little or no vertical exaggeration; this allows the cross section to accurately represent the relative positions of the layers.

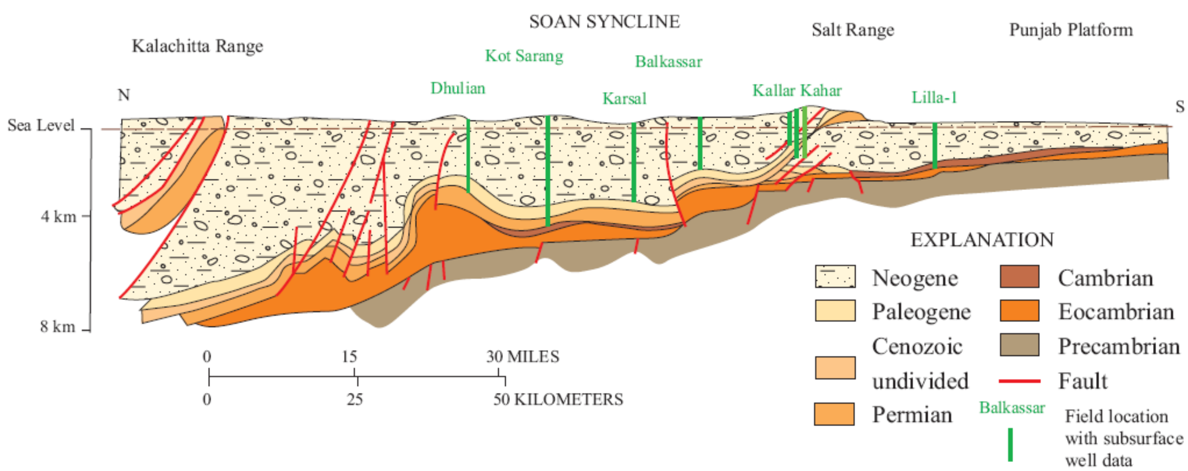


Figure A-2: Structural Cross Section of the Soan Syncline, Kohat-Potwar Geologic Province, Upper Indus Basin, Pakistan.
From: Wandrey et al. (2004).

Dipmeter Logs

Dipmeters are designed to measure the dip of the stratum and the dip direction of layered rock surfaces that intersect the well. To generate a dipmeter reading, microresistivity sensors are mounted on a caliper logging tool. A minimum of three calipers is needed, but most modern dipmeters have six or more sensors to provide redundancy in case of failure, as well as to improve results (Johnson and Pile, 2006). The dip is calculated based on depth, the positions of the sensors, and the diameter of the well. If two or more sensors are present on the same caliper, small-scale features such as cross-bedding and directional sand transport can sometimes be identified (Johnson and Pile, 2006). Dipmeter logs can also be used to identify structural features such as faults and folds when compared to standard dip models such as the one shown in Figure A-3.

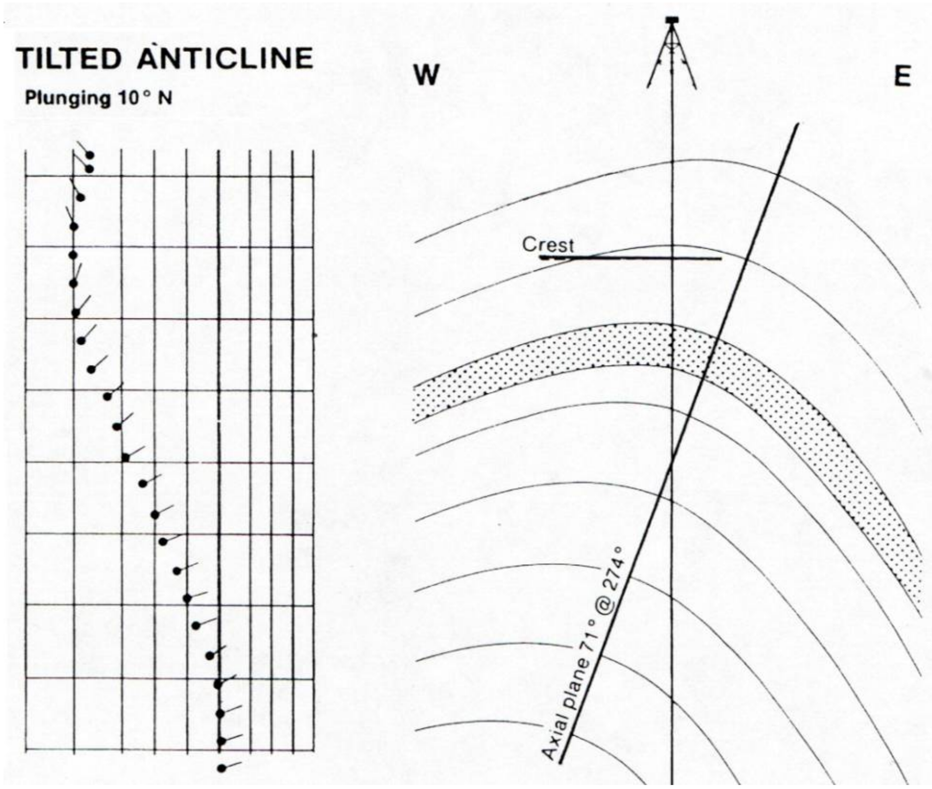


Figure A-3: Dip Model of a Tilted Plunging Anticline as it would Appear on an Arrow Plot of Dipmeter. From: Goetz, 1992; © American Association of Petroleum Geologists (AAPG) 1992, reprinted by permission of AAPG whose permission is required for further use.

Facies Analysis

Facies analysis can inform conclusions about whether to expect good lateral connectivity within the formation and whether there are barriers to vertical connectivity. Ambrose et al. (2008) have discussed the importance of facies changes to GS projects. Beach and barrier island deposits, for example, tend to be homogeneous and continuous. Fluvial facies produce heterogeneity in the reservoir because the fluvial channels are associated with fine-grained floodplain deposits; this heterogeneity may produce more limited, poorly connected areas for carbon dioxide storage. In some settings (e.g., the GS project at Sleipner), mudstone layers serve as permeability barriers, forming baffles that limit the buildup of buoyant pressure in the injection formation (Chadwick et al., 2008).

Variable porosity/permeability distributions are related to grain sizes, facies changes, and variability in cementation (Norden et al., 2010), and a good facies model will be valuable for understanding these variations. However, some fine-grained deposits may also have high porosity and permeability. These grain size and facies variations cannot be used exclusively as an indicator of permeability. Furthermore, diagenetic (post-deposition) processes also govern the characteristics of formations, especially carbonates. Like descriptions of clastic systems, descriptions of carbonate facies are based on observations of rock fabrics and pore spaces from core and cutting samples. These descriptions are correlated with wireline log responses and other information to map porosity, saturation, and permeability (Lucia, 1992). Because the characteristics of carbonates are often strongly (and sometimes completely) determined by the sediments' interactions with formation fluids, understanding current and past hydrogeology is also important in the analysis of carbonate facies.

A sequence stratigraphic approach focuses on surfaces (unconformities) that divide the sediments into chronostratigraphic units and allows strata to be correlated and then extrapolated to areas where data are lacking. Sequence stratigraphy is well established and is widely used in the oil and gas industry to characterize reservoirs and may be a useful approach for a GS project; it has already been used in the characterization of facies in some GS projects (e.g., Gibson-Poole et al., 2005). Additional information is available in the following sources: Lang et al. (2001); Van Wagoner et al. (1990); Posamentier and Allen (1999).

A2. Information to Support Petrologic and Mineralogic Analyses

The Class VI Rule requires the owner or operator of a proposed Class VI injection well to submit data on the mineralogy of the injection and confining zone(s) [40 CFR 146.82(a)(3)(iii)]. This section provides background information on conducting petrologic and mineralogic analyses to support meeting this requirement, including analysis by polarized light microscopy, scanning electron microscopy, and XRD. For additional information and recommendations, see Section 2.3.4 of the guidance (Petrology and Mineralogy of the Injection and Confining Zones).

Examples of Mineralogic and Petrologic Features Relevant to GS

The most common lithologic types in oil and gas reservoirs and deep saline formations are sandstone, limestone, and dolomite. The major minerals in sandstones include quartz and feldspar, with calcite (often as cement) and clay fines common as lesser components. Limestones and dolomites consist primarily of carbonate minerals (calcite, aragonite, dolomite). “Impure” limestones may have minor quartz grains, pyritic limestone contains pyrite, and argillaceous limestones contain clay components (Williams et al., 1982). Figures A-4 and A-5 show examples of thin sections of a sandstone and a fossiliferous limestone.

Shales and mudstones (clay-silt mixtures) will be common in the confining zones of GS projects. These lithologies consist of clay minerals and small particles of quartz, feldspar, and mica. Individual particles may be difficult to see by optical microscopy (Figure A-6), and, aside from general confirmation of the lithology and texture, limited information can be gained. If detailed information is desired, a scanning electron microscope (SEM) may be considered.

Some of the textural features that might be observed in thin sections and under SEM include cementation (secondary minerals providing cohesion to the rock), dissolution features (indicative of removal of minerals), pore size and shape, and the presence of fine clay minerals. For example, in Figure A-5, the carbonate cement can be seen infilling voids within the fossils and in between the fossil fragments. The extent of these features is integral to understanding porosity and permeability and for anticipating changes that may take place as a result of interactions between the injectate, native fluids, and formation solids.

The composition, grain size, grain shape, and sorting seen under a microscope can all be used to infer the depositional environment. This facies analysis can help in locating changes in physical parameters. For example, if grain size is seen to decrease upwards, a corresponding decrease in permeability may be seen. Such observations are considered a routine part of the determination of reservoir quality in the oil and gas field (e.g., Grier and Marschall, 1992) and would be valuable as part of storage formation characterization. A detailed discussion of the genesis, composition, and textures of rocks is also provided in Williams et al. (1982).

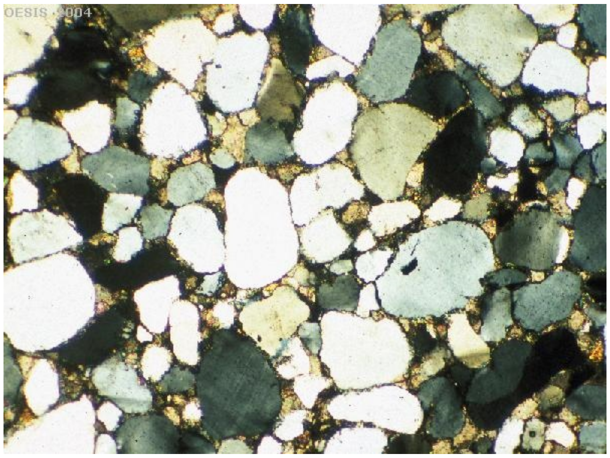


Figure A-4: Sandstone Cemented with Calcium Carbonate, Viewed under Crossed Polarizers.
Field of view is 3.5mm. The white and gray shapes are individual grains of sand, the tan in-between the sand grains is pore space filled with calcite cement. From: Univ. of Oxford (2010); © David Waters and the Department of Earth Sciences, University of Oxford, reproduced with permission.

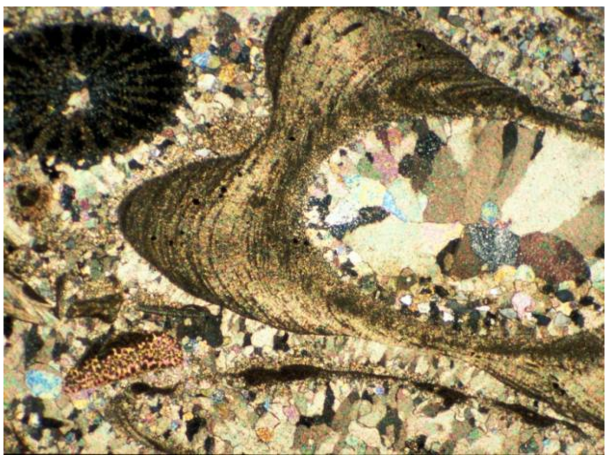


Figure A-5: Limestone With Fossil Fragments, Viewed under Crossed Polarizers.
Field of view is 3.5mm. The angular tan and blue shapes are calcite crystals filling in pore space. From: Univ. of Oxford (2010); © David Waters and the Department of Earth Sciences, University of Oxford, reproduced with permission.

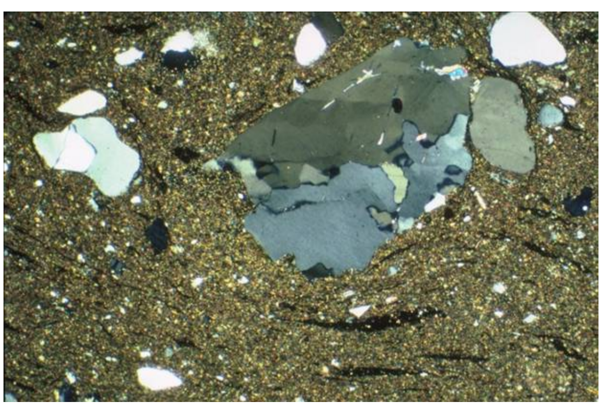


Figure A-6: Grains of Sand in a Shale Matrix, Viewed under Crossed Polarizers.
Field of view is 2mm tall. Quartz sand grains are gray and white. From: Schieber (2006); © Juergen Schieber, reproduced with permission.

Analysis by Polarized Light Microscopy

The petrographic microscope is a fundamental tool for identifying and characterizing rock and mineral samples. Samples are prepared by mounting chips of the rock onto glass slides, cutting and grinding down to a thickness of 30 microns, and polishing. Poorly consolidated samples are often impregnated with epoxy prior to cutting them into chips.

A petrographic microscope is a transmitted light microscope designed for the examination of rock thin sections. It includes a rotating stage and polarizers both above and below the stage; the specimen is examined both with the upper polarizer in place ("crossed polarizers" or "crossed nicols") and with it removed ("plane polarized light"). When the upper polarizer is inserted, the vibration directions of the two polarizers are perpendicular. This arrangement takes advantage of the optical properties of minerals; those that are not isotropic have more than one index of refraction, and light passing through is split into separate rays with different velocities. Under crossed polarizers, the difference in the velocities produces interference colors, which helps with mineral identification when taken together with cleavage, shape, and other characteristics.

Petrographic microscopes have remained relatively unchanged in principle since their development in the late 1800s. Edwards (1916) and Kerr (1959) are examples of classic texts that are still available on the optical properties of minerals, descriptions of the petrographic microscope, and mineral identification using the microscope. Basic descriptions of petrographic microscopes are commonly available on the Internet.

Careful petrographic analysis can provide information about the minerals present, the relationships among them (e.g., overgrowths), textures, grain size, and weathering (e.g., rounded grains in a clastic sediment). Williams et al. (1982) provide details on the mineralogy and textures to be expected in different rock types and how they relate to rock formation.

Scanning Electron Microscopy

SEM uses a beam of electrons instead of visible light, permitting much higher resolution and magnification than a petrographic microscope. The term "scanning" refers to the raster pattern used in moving the electron beam over the sample surface (similar to a television). The same thin sections prepared for light microscopy can be used in a scanning electron microscope. Also, unconsolidated samples can be prepared for analysis by mounting them onto a glass slide using adhesive.

The most common use of an SEM is for secondary electron imaging (SEI). In this mode, it produces a high resolution image of the sample surface with good depth of field. This function can image grain morphology and other features in loose samples affixed to a slide, but it is not appropriate for thin sections because they are polished flat. The oil and gas industry uses SEM in this capacity for assessment of reservoir quality (Grier and Marschall, 1992).

With thin sections, an SEM can be used in backscattered electron (BSE) mode. The signal from backscattered electrons depends on the atomic weight of the material being examined. Minerals are seen with different levels of brightness, with higher density minerals appearing brighter. This can be helpful for distinguishing minerals that appear similar under light microscopy. The same types of textural relationships would be seen as with a petrographic microscope, but very fine grains such as clay minerals and other clay-sized particles can be identified, as can mineral coatings and cements. Also, an elemental analysis of the minerals can be obtained if the SEM is equipped for energy-dispersive X-ray spectroscopy or wavelength-dispersive X-ray spectroscopy. Such analyses are point measurements, allowing analysis of specific sections of a mineral grain or of cements and grain coatings. Energy-dispersive spectra can be quickly viewed during examination as a qualitative aid in mineral identification in addition to being used for quantitative analysis.

Images taken in BSE mode can be used in petrographic image analysis to calculate estimates of porosity, permeability, and capillary pressure based on 2D measurements (Welton, 2004).

X-ray Diffraction

XRD may be useful for verification of mineralogy or identification of clay minerals. XRD helps to identify minerals based on structure rather than chemistry. The most common method for geologic samples is powder XRD, in which a slurry of the ground specimen is allowed to dry on a glass slide, which is then placed in the diffractometer. The sample is exposed to a beam of X-rays, which are diffracted by the various planes within the structure of the mineral. The angle of refraction for each plane is determined by Bragg's Law. During the analysis, a detector is moved through a range of angles relative to the sample and registers the angles at which X-rays are detected. The resulting pattern of X-ray peaks is used to identify the mineral. If multiple minerals are present, the patterns will be superimposed upon each other, and a qualitative estimate of the relative quantities of the minerals may be possible. XRD may be especially useful for identifying clay minerals, which are too fine to fully characterize by polarized light microscopy. Moore and Reynolds (1989) provide a thorough coverage of the theory and practice of XRD, with a focus on its application to clay minerals.

Use of Mineralogic and Petrologic Information

Data on the characteristics of the solids in the injection and confining zone(s) can also support an evaluation of the potential for geochemical reactions between the carbon dioxide, brine, and minerals that may cause changes in geomechanical and operational parameters or result in mobilization of contaminants. Lowered pH in the near-well bore region would promote dissolution of any carbonate minerals and cements in the injection formation, and precipitation of carbonates may occur in the more distal regions where pH is higher. Such reactions may affect porosity, permeability, and injectivity (Cailly et al., 2005). The kinetics of the dissolution and precipitation of silicates in clastics are slower (Palandri and Kharaka, 2004); certain lithologies such as clean sandstones will be less reactive in a carbon dioxide-rich system. Certain reactive clays and mafic silicates, however, may provide cations for precipitation of authigenic carbonates. Relatively rapid formation of carbonates would be expected in basalts (McGrail et al., 2006). Sulfide minerals and iron oxides may be dissolved and can liberate metals. Thus, an accurate assessment of mineralogy is important for predictions of long-term effects of injection on the properties of the injection formation.

A3. Information to Support Submittal of Data on Porosity, Permeability, and Capillary Pressure of the Injection and Confining Zones

Owners or operators must submit data on porosity, permeability, and capillary pressure of the injection and confining zones, per 40 CFR 146.82(a)(3)(iii). This section provides background information to support meeting this requirement. For recommendations on meeting this requirement, see Section 2.3.5 of the guidance on Porosity, Permeability, and Capillary Pressure of the Injection and Confining Zones. Additional information on capillary pressure is also provided in Section A8 of this Appendix.

Porosity

Factors Affecting Measured Porosity

Porosity is controlled by many variables. In sedimentary rocks, porosity is a function of the packing, sorting, grain size, and grain shape of the individual particles as well as in situ stress (Cone and Kersey, 1992). Pore space can occur as space between grains, as micro-scale pores along grain surfaces or other boundaries (when spaces are less than 2 μm), or along fractures. It can also be controlled by dissolution features (typically in carbonates). In clastic rocks, intergranular pore space is generally the most significant, especially in loosely packed, medium to large grain well-sorted lithologies such as clean sandstones. Fractures are usually the most important contributors to porosity in non-sedimentary rocks although there are exceptions, e.g., vuggy basalts can have porosities up to 12% (Fetter, 1988). Clastic rocks on average have the highest porosity of any rock type, with sandstones having up to 40% pore space (Cone and Kersey, 1992). The porosity of carbonates varies widely but is usually between 5 and 25% (Cone and Kersey, 1992).

Shales, which generally are potential sealing formations, usually have higher porosity than sandstones upon deposition (up to 80%) but experience rapid decreases in porosity with burial compaction and additional diagenesis (Avseth et al., 2010). The mean porosity for over 100 samples of Devonian-age shale was 3.6–4.1%, with extremes of 1.2–7.6% when measured using helium gas resaturation (Davies et al., 1990). However, the study also noted difficulties in measuring shale porosity because low values may be near the resolving limit of some techniques and small pore size (averaging 0.05 μm in some shales (Soeder, 1988)) can complicate some techniques.

The method of sample collection can influence the measured porosity. For lithologies with greater than 30% porosity, samples collected with sidewall cores tend to yield porosity measurements that are below actual values by a few percentage points because of compaction during coring (Almon, 1992). Damage to samples collected with percussion methods can further distort results. For low porosity units, measured porosities can be over-represented because porosity is enhanced by damage that occurs during coring, while for high porosity formations, compaction and grain shattering can reduce measured porosity (Almon, 1992).

Igneous and metamorphic rocks usually have low porosities. However, some volcanic tuffs are very porous and pumice can have up to 87% absolute porosity (Fetter, 1988). Weathering can also greatly increase porosity of these lithologies; weathered ultramafic and plutonic rocks can have porosities up to 60% due to the breakdown of minerals such as mica (Fetter, 1988).

Porosity Measurement

Field Methods

In the field, neutron logs, density logs, and sonic logs are well-suited to help estimate porosity (Aguilera, 1992). Neutron logs can be used in cased or uncased wells. With this method, a neutron-emitting probe is lowered into a well, and neutrons are captured by the hydrogen atoms in trapped pore water, gas, and hydrocarbons and are re-emitted as gamma rays. The probe logs the total amount of gamma radiation and estimates the pore fluid volume. One downside to this method is that water bound to clays can over-represent porosity in shales, siltstones, and other clay-rich units. As a result, a neutron log is collected and processed with other logs such as density logs or gamma ray logs to ensure accuracy. Porosity values collected from neutron logs are also absolute porosity; space in isolated, disconnected vugs that is not available for fluid storage is captured in the measurement. Another potential problem is that the neutron log cannot be used to determine the type of pore fluid present, which may be an important consideration when determining total storage capacity and injectivity.

Density log data are collected using a sonde equipped with a source of gamma radiation and at least one gamma ray detector deployed in a well. As it enters the formation, the radiation is scattered according to bulk density. Porosity can be calculated from density log data if the lithology of the subsurface and the saturating fluid are known:

$$\textbf{Porosity} = \frac{(\rho_{matrix} - \rho_{bulk})}{(\rho_{matrix} - \rho_{fluid})} \qquad \text{Equation 1}$$

where ρ_{matrix} is estimated based on the lithology (e.g. sandstone = 2.65 g/cm^3, limestone = 2.71 g/cm^3, and dolomite = 2.87 g/cm^3, etc.), ρ_{bulk} is from the density log, and ρ_{fluid} is estimated based on the salinity and hydrocarbon makeup of the saturating fluid (e.g. water = 1 g/cm^3, etc.) (Alberty, 1992a; Dewan, 1983).

Sonic logs measure the speed of sound in a formation. As a sonic probe is pulled up a well, it emits a sound wave and logs the time any reflected sonic waves arrive back at the receiver. If the lithology of the layer is known, the porosity can be deduced from deviation from the theoretical sonic travel time for a layer of the same lithology with zero porosity. The Wyllie time average method or the Raymer-Hunt-Gardner methods are two common methods used with sonic logs. Sonic logs work best when the pore fluid is water or brine. Additional descriptions of these logs are provided in Section A7.

Laboratory Methods

Several laboratory methods are available to determine porosity. These methods provide values for effective porosity. However, there is no good laboratory method for determining absolute porosity. Because porosity is stress dependent, laboratory measurements should be taken at stress conditions similar to in situ conditions (Cone and Kersey, 1992). Furthermore, core samples represent point measurements. For reliable results, measurements are best made on a number of cores, and the applicant might consider submitting a statistical representation of measurements such as a variogram.

If an unaltered, fresh sample of the formation of interest is available, the summation method can be used. Gas, oil, water, and any other fluids are extracted from the rock using a vacuum or other method. The sum of extracted fluids is assumed to equal the sum of the pore space. This method is potentially problematic, however, because the sample is not cleaned and because core samples are often subject to damage (e.g., mud intrusion, etc.) during retrieval, which can displace pore fluids.

With a less pristine sample, a resaturation method can be used. First, the sample is cleaned and dried, which allows for the remediation of some damage incurred during drilling. Hydrocarbons are generally removed from samples using toluene. The sample is then heated until it maintains a constant weight. One potential problem with this method is that if brines are present, precipitation of salts can reduce the porosity (Cone and Kersey, 1992). If smectite, gypsum, or clay minerals are present, samples should be dried at 63˚ C and 45% humidity to prevent removal of structural water and damage to clay minerals (Cone and Kersey, 1992).

Once the sample remains at a constant weight, indicating that all fluids have been driven off, the sample is then saturated with either a liquid (usually water) or a gas. Helium is usually the gas of choice because it does not adhere to mineral surfaces and its small molecule size allows it to diffuse into micropores. If liquid resaturation is chosen, the sample is saturated with liquid and re-weighed. For rock samples with very small pore sizes, the choice of displacing and saturating fluid used during the porosity measurement may introduce variability into the final results because of the attraction between pore surfaces and displacing fluids. The amount of pore space is deduced from the density of the saturating liquid. In gas resaturation, the sample is placed in a confined volume and resaturated with gas from a referenced cell. The volume of pore space is determined from the change in the pressure in the reference cell through the ideal gas law ($pV = nRT$). Gas resaturation should not be used with vuggy or fractured samples.

Dry methods are also available. Thin sections of rocks made from core samples can be analyzed under a polarized light microscope or scanned and analyzed with specialized software (petrographic image analysis). Less commonly used laboratory methods to determine porosity include X-ray computerized tomography (CT scanning) and nuclear magnetic resonance imaging.

Permeability

Permeability refers to the property of a porous medium to transmit fluids under a hydraulic gradient (USGS, 1989). Several physical factors can influence permeability. These include median pore size and connectivity of the pore space within the material (e.g., Bachu and Bennion, 2008). Grain size is also a significant factor; because all wetted grains have a boundary layer of fluid with a velocity of zero, more energy is expended in overcoming shear forces between the boundary layer and through fluids when the grain size is small (Schlumberger, 2006).

Absolute (Intrinsic) Permeability

Absolute permeability, also known as intrinsic permeability, is the permeability of a material when only one fluid is present. It is dependent only on the properties of the material and not the fluid. Absolute permeability can be calculated from laboratory analyses of a core sample as:

$$\textbf{Absolute Permeability} = \frac{Q\mu L}{A_f \times (p_2 - p_1)} \qquad \text{Equation 2}$$

where Q is the flow rate through the core, μ is the fluid viscosity, L is the length of the core, A_f is the cross sectional area of the core, and $(p_2\text{-}p_1)$ is the pressure difference on either side of the core. Permeability values of different lithologies can vary by orders of magnitude (Table A-1), with salts and shales typically exhibiting lower permeability values and sandstones having the highest values.

Table A-1: Typical Permeability for Various Lithologies.
From: Davis (1988).

Lithology	Permeability (mD)
Shale (unfractured)	4.7×10^{-5}
Sandstone	3.8-4,740
Coal	334
Salt	9.61×10^{-5}

Because geologic materials are inherently heterogeneous, absolute permeability will vary spatially. Furthermore, permeability is an anisotropic property that varies in the x, y, and z directions and typically shows the greatest variation in the direction perpendicular to layering. For the computational modeling performed for AoR delineation, a realistic representation of the permeability distribution is needed. Approaches for handling the distribution of permeability, including geostatistical approaches are discussed below and in Section 2 of the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*.

Effective Permeability

Effective permeability measures the permeability of a material to one fluid when more than one fluid phase is present (such as carbon dioxide in brine or oil). In addition to pore size distribution, effective permeability is affected by the relative saturation of fluids within a material and the interfacial tension (IFT) between the fluids (Bachu and Bennion, 2008). Because IFT is influenced by in situ conditions such as pressure and temperature, these variables can also influence effective permeability. Due to its dependence on the IFT and the relative saturation of fluids, effective permeability in a GS project is expected to vary spatially and temporally as the pressure and distribution of brine and carbon dioxide change.

Relative Permeability

Relative permeability is the dimensionless ratio of the effective permeability to absolute permeability. It varies from 0 to 1. Relative permeability is relevant to site characterization for GS because one phase or fluid can inhibit or facilitate the preferential flow of another phase or fluid. Because relative permeability varies with the relative saturations of the fluids, it may be expressed as a relative permeability-saturation function for incorporation into computational modeling. See the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for more information. Relative permeability has been studied extensively due to its importance in hydrocarbon extraction (Schlumberger, 2006). For GS, changes in the relative permeability may result in improved or reduced injectivity into reservoir rocks and/or improved or reduced sealing capacity for confining formations.

Many mathematical methods for obtaining relative permeability are available. One of the simplest is the Pirson model, which uses the saturation of the wetting phase before and after drainage of a core sample to determine the relative permeability of the wetting phase:

$$\boldsymbol{K}_{r(\boldsymbol{i})} = \boldsymbol{S}_{\boldsymbol{i}}^{3} \left[\frac{(\boldsymbol{S}_{\boldsymbol{i}} - \boldsymbol{S}_{\boldsymbol{ir}})}{(\mathbf{1} - \boldsymbol{S}_{\boldsymbol{ir}})} \right]^{\mathbf{1.5}} \qquad \text{Equation 3}$$

where S_i and S_{ir} are the initial saturation and residual saturation of the fluid.

Relative permeability measured in the laboratory is often found to depend on many factors, including pore size and IFT, which in turn depends on in situ pressure, temperature, overburden pressure, wettability, and salinity conditions (Bachu and Bennion, 2008; Hawkins, 1992). A lower IFT encourages the transport of the non-wetting phase through the pore space, leading to an increase in the relative permeability. Hysteresis effects may also influence relative permeability (Hawkins, 1992). This may be important for fields with previous water and carbon dioxide flooding histories or if injection of carbon dioxide is not done at a constant rate.

Permeability data for several different fluids/mixtures within the reservoir may be needed to fully characterize behavior of the injectate at carbon dioxide storage sites as injection progresses. These fluids/mixtures are:

- Brine, hydrocarbon, or other initial reservoir fluid;

- Carbon dioxide/reservoir fluid mixture; and
- Pure carbon dioxide.

Initially, the permeability depends only on the behavior of the reservoir fluid. Next, permeability becomes dependent on a mixture of two or more liquids as injectate is introduced into the reservoir. Bachu and Bennion (2008) found that the permeability of sandstone, carbonate, and shale core samples taken from a typical intracratonic sedimentary basin to carbon dioxide at irreducible water conditions was one-fifth that of brine at 100% brine conditions for lithologies with permeabilities greater than 1 mD.

As large volumes of carbon dioxide are injected, a new zone may form near the injection well as the carbon dioxide saturation increases and the reservoir fluid is completely displaced. Once again, the permeability is dependent on a single fluid: this time the injected carbon dioxide as opposed to the native reservoir fluid. This zone is called the “dry-out” zone. Salts will precipitate out of the migrating brines, potentially decreasing permeability (Burton et al., 2009). However, the presence of a dry-out zone may increase injectivity because the effective permeability (the product of intrinsic and relative permeability) of carbon dioxide in the dry-out zone exceeds the effective permeability of carbon dioxide in the two-phase region (Burton et al., 2009).

Measuring Permeability

Permeability can be quantified using in situ field measurement techniques (e.g., well tests, well logging) or laboratory methods (using cores). Unlike other parameters (e.g., viscosity, temperature, pressure), permeability is calculated indirectly from values derived from other measurements (e.g., capillary pressure, IFT). As a consequence, permeability can vary depending on the method used. Additional discussion is provided below.

It should be noted that permeability measurements can differ by scale. Well tests are representative of a much greater area (scale) than core samples, which represent a much smaller scale (sampling point) (Ellis and Singer, 2007). As such, well testing tends to provide composite representations of localized variability. Permeability derived from well logs represents an intermediate scale between core logs and well tests.

Field Methods

Permeability can be estimated in situ using a variety of methods. Pressure changes during drawdown tests can be analyzed quantitatively or, if multiple wells are available, variable flow test analysis can be used to determine permeability provided that the reservoir pressure, flowing bottomhole pressure, flow rates, and the total time of the test are known (Smolen, 1992; Matthews and Russell, 1967).

The absolute permeability can also be determined from the hydraulic conductivity (Lewis et al., 2006) using the relationship:

$$\textbf{Absolute Permeability} = \frac{K\mu}{\rho g} \qquad \text{Equation 4}$$

where K is the hydraulic conductivity, μ is the dynamic viscosity of the liquid, ρ is the density of the liquid, and g is the acceleration due to gravity.

An important consideration in field measurements pertains to the effective permeability of the existing well bores. Gasda et al. (2008) present a method to determine the permeability of the near-well bore region, which may differ due to damage during drilling (skin effect), using the pressure in units above and below confining formations. The method can identify permeability along the well bore even when it is greater than reservoir permeability. Additional discussion of skin effects is provided later in this Appendix (Section A8).

Permeability can also be estimated from well log data. This is accomplished with an estimator of porosity such as a density log. Several empirical approaches have been developed to relate porosity, resistivity, and other parameters (e.g., irreducible water saturation) to permeability, with early work starting in the 1920s. Some empirical relationships are more suitable for certain rock types or textures; a summary and comparison of the various empirical methods are given by Balan et al. (1995). Nelson and Batzle (2006) also provide a description of methods for permeability estimation from well logs. These include multiple linear regression approaches using porosity and other variables and involve dividing the formation into zones with different lithologies, compositions, and flow histories.

Laboratory Methods

Absolute Permeability

Permeability measurements in the laboratory can be conducted with water, brines, gases, or other fluids when core samples are available. However, determining permeability from downhole cores may be difficult if damage has occurred during drilling. Permeability in core material can be reduced by as much as 80% due to the infiltration of mud, fine material, or other particles into the pore spaces of the core. Plug samples taken from the center of the core may be the best way to avoid such damage and generate a representative measure of permeability. Sandblasting the outside of whole-core samples may remove some built-up fines and improve results, but it cannot remediate mud that may have worked into the pores (Almon, 1992). Permeability can also be measured from sidewall cores. However, sidewall permeability measurements are often erroneously high for hard, dense formations because of grain shattering and other damage during the coring and extraction of the side wall core. Conversely, permeability measurements taken from sidewall cores for loose, friable (crumbly) formations are often erroneously low due to grain shattering introducing fines into pore spaces (Almon, 1992).

Once an appropriate lithologic sample has been isolated, it can be analyzed. The most common laboratory methods involve isolating a sample of core in a non-permeable sleeve while injecting a fluid material into the core. Measurements taken using a single fluid yield information on absolute permeability. Lead sleeves are often used because traditional sleeve materials allow the diffusion of carbon dioxide across the sleeve. Also, lead sleeves transfer pressure radially throughout the core if experiments are conducted at in situ pressure conditions.

Gas (air) and brine are the most common fluids used for injection in conducting permeability tests. Gas permeability is the industry standard for hydrocarbon exploration because it is the easiest to produce. While gas and brine tests produce similar permeability results when permeability is high, gas permeability tends to be higher when the permeability is low because frequent collisions of gas molecules with the pore walls help propel the gas molecules forward. Gas methods are also corrected for gas slippage effects at low pressures and inertial effects at high pressures (Ohen and Kersey, 1992).

The pressure difference across the core after the flow has stabilized can be transformed into a permeability measurement using a modified version of Darcy’s Law. A non-steady-state variant of this method measures the gas pressure decay across the core. Non-steady-state methods usually produce more accurate results. Experiments can be conducted in a temperature controlled environment to simulate reservoir conditions when measuring effective permeability.

When permeability is measured from a whole core, measurements are usually reported in two directions: one parallel to the major fracture planes and other at 90 degrees perpendicular to this direction (Almon, 1992). Measurements may also be needed along the core in order to gain a representative understanding of permeability within the unit.

Relative Permeability

Although both effective and relative permeability can be measured in the laboratory, relative permeability is more commonly measured and reported (Abaci et al., 1992; Ahmed, 2006). Several methods are available. One common method uses a setup similar to absolute permeability methods except that after initial saturation and pressure equilibration, a second fluid is introduced and driven though the sample until the saturation and pressure differential across the sample returns to a constant value. A faster alternative is the unsteady-state method, in which a stream of gas is injected into a sample to displace a liquid. However, mathematical calculations are more complex when using the unsteady-state method.

Several types of corrections have been applied to core data. The Klinkenberg correction, which is important for low-permeability rocks, relates permeability for liquids to gas permeability. The pore fluid chemistry, especially salinity, may also affect permeability. Another type of adjustment is a correction for the dependence of permeability on pressure. For example, unconsolidated rocks can collapse, reducing permeability. These corrections are described by Nelson and Batzle (2006).

Petrographic Image Analysis

Petrographic image analysis (PIA) is an established method employed in the oil and gas industry to derive 3D petrophysical properties (porosity, capillary pressure, permeability, relative permeability) from 2D measurements of pore size and geometry. It can be used for characterization of sandstones, carbonates, and conglomerates, and it is inexpensive and rapid (Gies, 1993).

To collect PIA data, standard petrographic thin sections are viewed under a petrographic microscope or SEM in backscatter mode (BSE), and the images are stored and analyzed using image analysis software. The sample will need to have been impregnated with epoxy to fill the pore spaces prior to making the thin section. If light microscopy is to be used, adding dye to the epoxy will make pore spaces easily visible and will facilitate the image analysis. In BSE images, the pore spaces will be darker grey than the mineral grains. During image measurement, a number of fields of view on the thin section will be examined to obtain a representative sampling of pore spaces. The number of images needed may vary according to the rock type and magnification (Solymar and Fabricius, 1999). The images allow quantification of the number, size, and structures of pores. Macroporosity can be determined, and, with the high magnification and excellent resolution achievable with SEM, microporosity can also be determined. Pore size distribution can be measured, as well as pore circumference and area. These properties can be used to estimate capillary pressure and permeability. Capillary pressure can be expressed as a function of porosity, pore perimeter, and pore surface (Cerepi et al., 2001). Permeability can be derived using the Carman-Kozeny model (Cerepi et al., 2001; Solymar and Fabricius, 1999), which relates permeability to the porosity, the pore area, and pore perimeter. Cerepi et al. (2001) have also evaluated an alternate model for permeability ("bundle of capillary tubes"), but achieved better results using the Carman-Kozeny model.

PIA has been found to produce porosity values that agree closely with data from other methods (core analysis, wireline logs data, petrographic methods) (Layman, 2004). With respect to permeability, Solymar and Fabricius (1999) found that PIA tends to yield higher values than measurements of liquid permeability. This method has become well established, and additional literature is available that further explores the basis of PIA methods and the relationship between PIA-derived parameters and those measured in the laboratory.

Other Permeability Estimation Methods Based on Petrophysical Data

In addition to the Carman-Kozeny model noted above, there are several equations that make use of the results of petrophysical analysis, including information that can be gained from PIA. Krumbein and Monk's equation uses mean grain diameter and the standard deviation of grain diameter (an indication of sorting). Berg's model links grain size, shape, and sorting to permeability. Van Baaren's model is an empirical variation on the Carmen-Kozeny model and is similar to Berg's (Nelson and Batzle, 2006).

Some models are based on pore dimension and use capillary pressure and pore size. For example, Winland's equation relates permeability to porosity and capillary pressure. Katz and Thompson's equation addresses the influence of pore structure on flow properties. Details are provided by Nelson and Batzle (2006).

Geostatistical Methods

Analyses of formation properties such as porosity and permeability from logs or core samples provide point measurements that cannot fully capture subsurface variability. However, representation of the distribution of porosity and permeability is valuable for the multiphase modeling required for AoR delineation under 40 CFR 146.84. Subsurface heterogeneity is difficult to represent using conventional models, and if adequate data are available, owners or operators may consider use of geostatistical approaches such as semivariograms, kriging, and stochastic simulations to estimate porosity and permeability distributions at the project site:

- *Semivariograms* characterize spatial correlations and are developed from field measurements. A semivariogram model can then be fit to an empirical semivariogram. A number of semivariogram models exist including nugget, spherical, exponential, Gaussian, and power models. Individual models or combinations of models may be fit to the data;
- *Kriging* and stochastic (see next bullet point) methods may be used to estimate parameter values at unsampled locations once a semivariogram model has been developed. Kriging is an interpolation method that calculates a statistically unbiased, best-fit estimate at each point, accounting for the hard data values and the correlations between the data. Kriging results are artificially smooth because the variability between estimated locations is not considered (Khan, 2003); and
- *Stochastic simulation* is a probabilistic approach that generates multiple, equally probable realizations of a variable. The result from this method is not a single best answer, but a range of possible outcomes. Examples of stochastic simulations include Monte Carlo and Sequential Gaussian Simulation. Stochastic simulations can also be employed after kriging to correct for the artificially smooth output from kriging (Khan, 2003).

Though geostatistical methods may be helpful for approximating parameter values at unsampled locations, the results may not always accurately capture the complexities of the subsurface geologic heterogeneities such as faults, lenses, and varying lithologies. Geostatistical methods are optimal when the data are normally distributed and stationary (i.e., mean and variance do not vary significantly in space). To improve the results, a number of alternative methods have been proposed for use in combination with geostatistics, including the coupled Markov chain (Park et al., 2003) and the use of artificial neural networks (ANN) (Wang and Wong, 1999). Owners or operators may also consider using cross-validation to validate the modeling results (Malvic, 2005).

Capillary Pressure

Several established methods are available for measurement of capillary pressure:

- *Mercury injection* - a dried core sample is injected with mercury in increasing pressure steps up to 60,000 psi. The pressure versus the mercury saturation is measured. This method is quicker than some of the other methods and can achieve much higher pressures. The disadvantages are that it uses mercury, and results need to be extrapolated to reservoir fluids. This method is effective for measuring pore throat size distributions, although not as effective for measuring capillary pressure in some formations such as tight sands;
- *Centrifuge* - core samples are centrifuged and the fluid forced out is measured. This test is relatively rapid, taking hours instead of days or longer. It can be performed at reservoir temperatures and pressures. The disadvantage is that this test has a maximum pressure

limit that is lower than mercury injection. Additionally, there may be cavitation if the capillary pressure is greater than atmospheric pressure. However, this test is well suited for poorly consolidated samples;.

- *Porous plate* - a porous membrane is used, and pressure is increased with a fluid. The pressure required to displace the pore fluid is measured. This method offers the advantage of using native fluids and does not require cleaning or drying of the cores. It can test a lower maximum pressure than mercury injection, and it is well suited for shales and clays. However, samples need to reach equilibrium, which can result in test lengths of days to weeks; and
- *Restored state cell* - the sample is initially saturated with brine. A non-wetting fluid is then introduced in small pressure steps. The pressure is increased until no more water is released. This method has the advantage that the electrical properties of the fluid can be measured as well. Furthermore, native fluids can be used. However, the disadvantage is that it takes longer than the centrifuge or mercury tests.

Newer techniques such as nuclear magnetic resonance and a vapor deposition technique may also be considered.

A4. Information to Support Geomechanical Characterization of the Confining Zone

The Class VI Rule requires geomechanical information to be submitted on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone [40 CFR 146.82(a)(iv)]. This section provides background information for understanding in situ fluid pressure and downhole stresses; this information supplements Section 2.3.6 of the guidance on Geomechanical Characterization. Data on pore pressure and stress data may also be used for analysis of fault stability (see Section A5 below and Section 2.3.2 of the guidance). References and methods are summarized in Table A-2.

Table A-2: Parameters and Data Needed to Define the Stress Tensor and the Geomechanical Model. After Chiaramonte et al. (2008).

Parameter	Data Collection Methods	Additional Information
Pore pressure	Measurement of downhole pressure by drill stem testing and production testing	Smolen (1992); Borah (1992); Lancaster (1992); Harrison & Chauvel (2007)
Vertical stress (S_v)	Integration of density logs over the desired depth	Zoback et al. (2003); Chiaramonte et al. (2008); Streit et al. (2005); Herring (1992)
Minimum horizontal stress (S_{hmin})	Leak-off tests (LOT), Extended LOT (XLOT)	Chiaramonte et al. (2008); Zoback et al. (2003); Streit et al. (2005)
Maximum horizontal stress (S_{Hmax})	Modeling well bore failure features such as drilling-induced tensile fractures (if S_v, S_{hmin} and pore pressure values are known) or stress-induced well bore breakouts (if S_v, S_{hmin}, pore pressure, and the rock strength are known)	Moos & Zoback (1990); Goetz (1992); Streit & Hillis (2004); Zoback et al. (2003); Streit et al. (2005)

Pore Pressure

Pore pressure can be measured by formation testers or by performing drill stem tests. Formation testers are specialty wireline tools used for measuring the pressure of the formation in an open hole (Smolen, 1992). In drill stem testing, the formation pressure is measured by sealing the zone of interest with well bore packers (Borah, 1992). After completing the well, additional pressure testing can be conducted by production testing such as single-point, multi-point, and swab testing (Lancaster, 1992). Bottomhole pressure may also be measured by pressure transducers. Transducers convert a pressure change into a mechanical displacement or deformation, which is then converted into an electrical signal (Harrison and Chauvel, 2007). Additional information regarding types of pressure transducers is available in Harrison and Chauvel (2007) and from commercial manufacturers as well as in the *UIC Program Class VI Well Testing and Monitoring Guidance*.

In Situ Stress Determination

The three principal stresses commonly assumed to characterize the geomechanical model of a site at depth are the vertical stress, S_v, the maximum horizontal stress, S_{Hmax}, and the minimum horizontal stress, S_{hmin} (Zoback et al., 2003; Streit et al., 2005). Fault slip occurs in normal faulting regions (gravity-driven faulting) when the minimum stress reaches a low value relative to the vertical stress ($S_v \geq S_{Hmax} \geq S_{hmin}$); folding and reverse faulting can occur in compressive stress fields when both of the horizontal stresses exceed the vertical stress and the maximum horizontal stress is sufficiently large relative to the vertical stress ($S_{Hmax} \geq S_{hmin} \geq S_v$); and strike-slip faulting occurs when the difference between S_{Hmax} and S_{hmin} is sufficiently large ($S_{Hmax} \geq S_v \geq S_{hmin}$) (Zoback et al., 2003).

The magnitude and orientation of the vertical stress, the minimum horizontal stress, and the maximum horizontal stress can be determined from drilling data and well logs. Methods for quantifying the magnitude and orientation of these principal stresses are summarized below.

Vertical Stress

Vertical (orientation) stress (S_v) can be obtained from density logs (Zoback et al., 2003). The magnitude of S_v can be obtained by integrating data collected from density logs over depth. Density logs measure the bulk density of the rocks in the well bore walls through gamma ray emissions (Chiaramonte et al., 2008; Herring, 1992; Streit et al., 2005). Vertical stress at the depth of interest can be calculated by the following equation (Chiaramonte et al., 2008; Streit et al., 2005; Zoback et al., 2003):

$$\boldsymbol{S_v(z_0) = \int_0^{z_0} \rho g dz} \qquad \text{Equation 5}$$

where z_0 is the depth of interest. In some cases (e.g., offshore wells), the analyst needs to account for the lower density of the water column and the transition to higher density with depth when evaluating the magnitude of vertical stress (Zoback et al., 2003). Additional editing and extrapolation of data may be necessary; for example, when borehole conditions are unfavorable and density data exhibit high levels of variability (Zoback et al., 2003).

Minimum Horizontal Stress

The magnitude of the minimum horizontal stress (S_{hmin}) in normal and strike-slip faulting regions can be determined with considerable accuracy through direct in situ formation stress tests (see Zoback et al., 2003). For deep wells where conventional in situ formation stress tests are not available, information about S_{hmin} can be collected by leak-off tests. A leak-off test is conducted by pumping into a well at a constant rate and recording the well bore pressure as a function of cumulative volume (or time if pumped at a constant rate). As described by Zoback et al. (2003), the pressure will increase linearly with volume (or time) until a distinct departure from a linear increase occurs (leak-off point or LOP) (Figure A-7). As pumping continues at constant rate, the maximum pressure reached is termed the formation breakdown pressure (FBP) and the pressure then falls below the FBP to a relatively constant value called the fracture pumping pressure (FPP). The FPP value should be similar to the LOP.

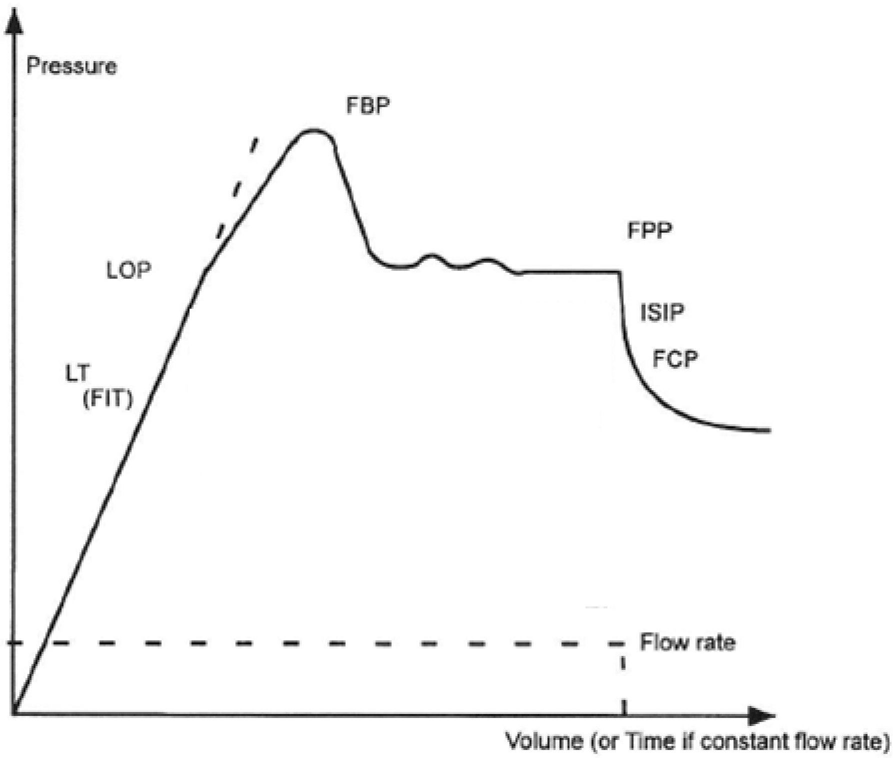


Figure A-7: Schematic Illustration of an Extended Leak-off Test and Associated Terms.
Where: LT= Limit Test; LOP= Leak-Off Point; FIT= Formation Integrity Test; FBP= Formation Break-down Pressure; FPP= Fracture Pumping Pressure; ISIP= Instantaneous Shut-in Pressure; FCP= Fracture Closure Pressure. From: Zoback et al. (2003); © Elsevier, reproduced with permission.

The extent that leak-off tests can be used to estimate S_{hmin} can be assessed by evaluating the data collected. Zoback et al. (2003) noted that test data that show that the leak-off point was reached can be considered "an approximate measure" of S_{hmin}. Further, Zoback et al. (2003) noted that, if the test data shows that a stable FPP was achieved, the test can be considered "a good measure" of S_{hmin}. Chiaramonte et al. (2008) described the use of information from leak-off tests to determine the fracture pressure limit of the confining zone at the Teapot Dome oil field in Wyoming.

Another technique, which uses annular pressure measurements during drilling operations, is described by Zoback et al. (2003) as a potential method for estimating the magnitude of S_{hmin}.

Maximum Horizontal Stress

In addition to the use of in situ stress testing, the magnitude of the maximum horizontal stress (S_{Hmax}) can be estimated based on knowledge of the vertical stress, S_v, and the minimum horizontal stress, S_{hmin}. The stress polygon method, as described by Zoback et al. (2003), can be used to estimate possible S_{Hmax} values associated with normal-gravity, reverse faulting, and strike-slip faulting environments, given the pore pressure at depth and available results of in situ formation stress tests or leak-off tests. Chiaramonte et al. (2008) applied the polygon method at the Teapot Dome oil field in Wyoming.

The orientation of S_{Hmax} can be determined from the orientation of borehole breakouts and drilling-induced tensile fractures. Borehole breakouts and drilling-induced tensile fractures can form in the well bore during drilling operations. Zoback et al. (2003) provide a theoretical discussion of effective stresses acting in a vertical well bore. Streit et al. (2005) provide an illustration of the occurrence of well bore breakouts (formation loss in the area of minimum horizontal stress) and drilling-induced tensile fractures (along the axis of maximum horizontal stress) in a borehole relative to the orientation of maximum and minimum horizontal stresses.

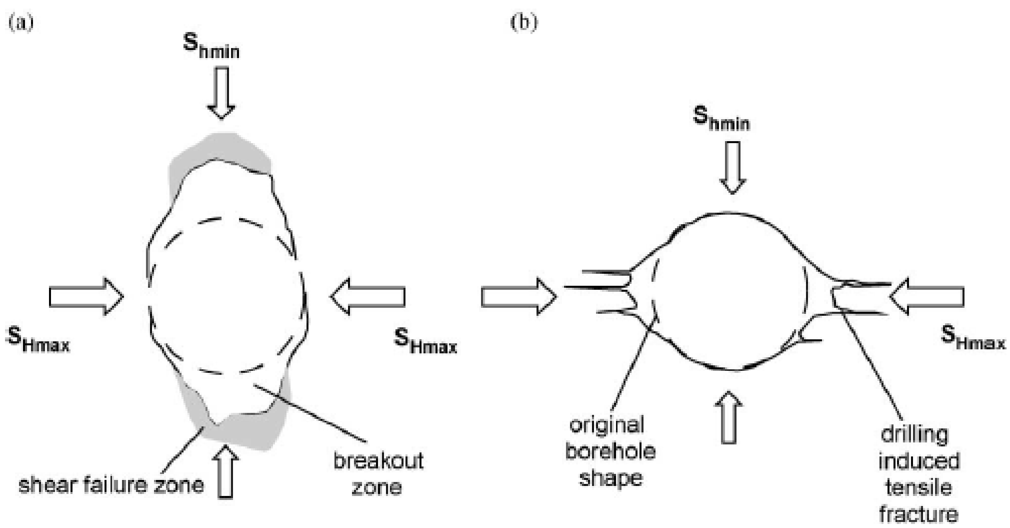


Figure A-8: Schematic Cross Section through Borehole.
(a) borehole breakout due to spalling of borehole wall indicating the Shmin direction. (b) drilling-induced tensile fractures indicating the S_{Hmax} direction. From: Streit et al. (2005); © Elsevier, reproduced with permission.

Well bore breakouts and drilling-induced tensile fractures can be detected through the use of image logs (Zoback et al., 2003). Figure A-9(a) is a standard “unwrapped” well bore image from an ultrasonic borehole televiewer. Borehole breakouts can be seen as dark bands on opposite sides of the well in Figure A-8(a), and as out-of-focus zones on opposite sides of the well in the formation microresistivity image (FMI) in Figure A-9(b). The orientation and opening angles of the breakouts are shown in Figure A-9(c). Figure A-9(a) also shows fractures oriented 90° from the well bore breakouts, which indicates the occurrence of failures associated with both well bore breakouts and drilling-induced tensile fractures (Zoback et al., 2003).

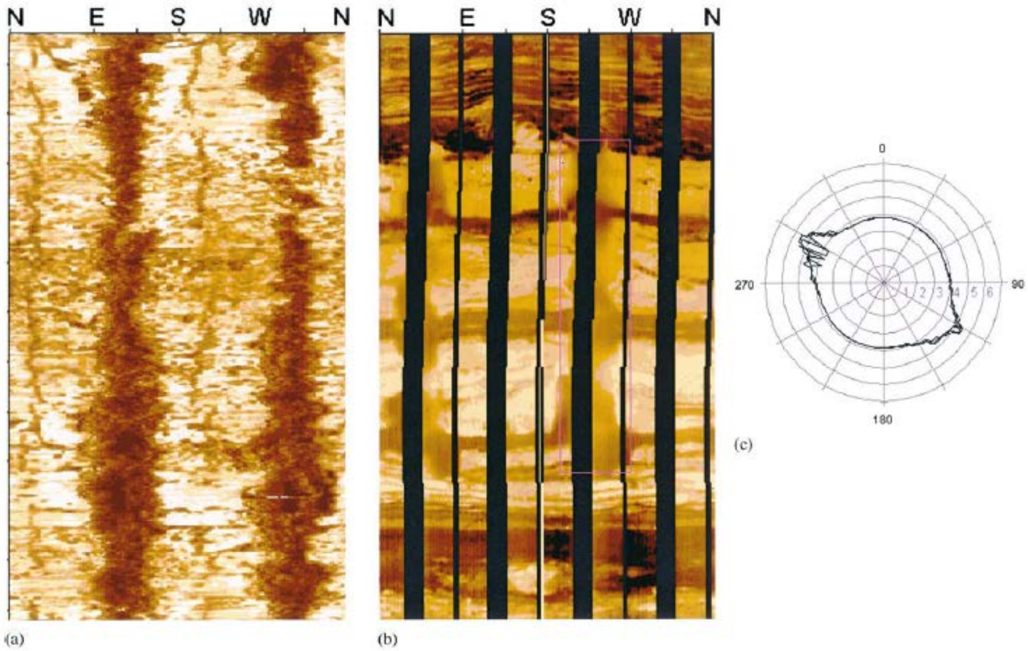


Figure A-9: Image Logs of a Well with Well Bore Breakouts.
(a) ultrasonic televiewer image logs (b) FMI log (c) cross sections of the well in (a). Breakouts are dark bands in part (a) and out-of-focus areas in part (b). From: Zoback et al. (2003); © Elsevier, reproduced with permission.

Another method that can be used to estimate S_{Hmax} is referred to as a frictional limit calculation (Zoback et al., 2003; Streit et al. 2005; Streit and Hillis, 2004). The relation equates the ratio of the maximum-to-minimum principal stresses to frictional sliding on cohesionless, optimally oriented faults (Streit et al., 2005; Streit and Hillis, 2004):

$$\frac{\sigma_1 - P_p}{\sigma_3 - P_p} = \left[\left(\mu^2 + 1\right)^{1/2} + \mu\right]^2 \qquad \text{Equation 6}$$

where σ_1 and σ_3 are the maximum and minimum principal stresses, respectively, P_p is the pore fluid pressure, and μ is the coefficient of static friction. The coefficient of static friction is generally considered between 0.6 and 1.0 for a range of rocks and faulting environments (Zoback et al., 2003).

The specific parameters used in Equation 6 for σ_1 and σ_3 are defined by the faulting environment (Zobak et al., 2003), as described previously. For example, a strike-slip faulting environment would be characterized $\sigma_1 = S_{Hmax}$ and $\sigma_3 = S_{hmin}$, while a normal faulting environment would be characterized by $\sigma_1 = S_v$ and $\sigma_3 = S_{hmin}$. An example plot of data used for estimating frictional limits is given in Figure A-10 (Streit et al., 2005). Example plots of stress magnitudes as a function of depth for various faulting environments are provided by Zoback et al. (2003). Techniques for stress determination in deviated wells (e.g., horizontal or wells drilled with complex trajectories) are described by Zoback et al. (2003).

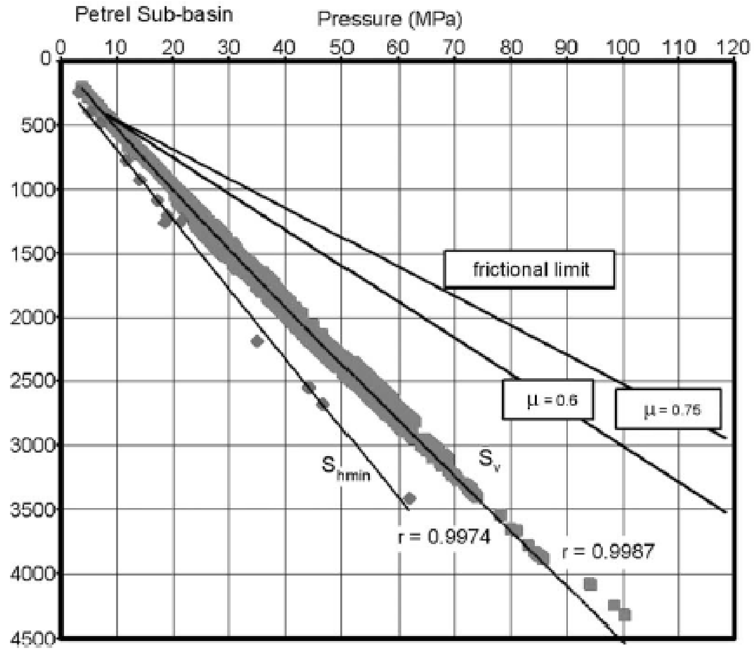


Figure A-10: Example Plot of Data Used for Estimating Frictional Limits (Petrel Sub-Basin, Australia). Shmin estimates are derived from pressure leak-off tests, and Sv estimates were obtained by examining density logs. R values are Pearson correlation coefficients. Vertical axis is meters. From: Streit et al. (2005); © Elsevier, reproduced with permission.

The orientation of borehole breakouts and tensile fractures (Figure A-11) can be determined from image logs and four-arm caliper logs. Six-arm caliper logs are also available, which may be able to provide more accurate and detailed data on borehole breakouts if four-arm caliper logs are not sufficient. FMI logs generate an electrical image of the borehole from microresistivity measurements, which penetrate about 30 inches from the well bore. FMI data are used to identify drilling-induced features and breakouts (Schlumberger, 2002). An application using FMI logs for the analysis of tensile fractures was described by Chiaramonte et al. (2008). Caliper logs (two-, three-, four-, or six-arm) can measure the enlargement of boreholes in the presence of natural fractures (Aguilera, 1992). Choosing a caliper log with a greater number of arms can increase the accuracy and level of detail in the resulting data. Breakout and tensile fracture data collected at depth from various wells can be used to develop stress maps such as those shown in Figure A-11.

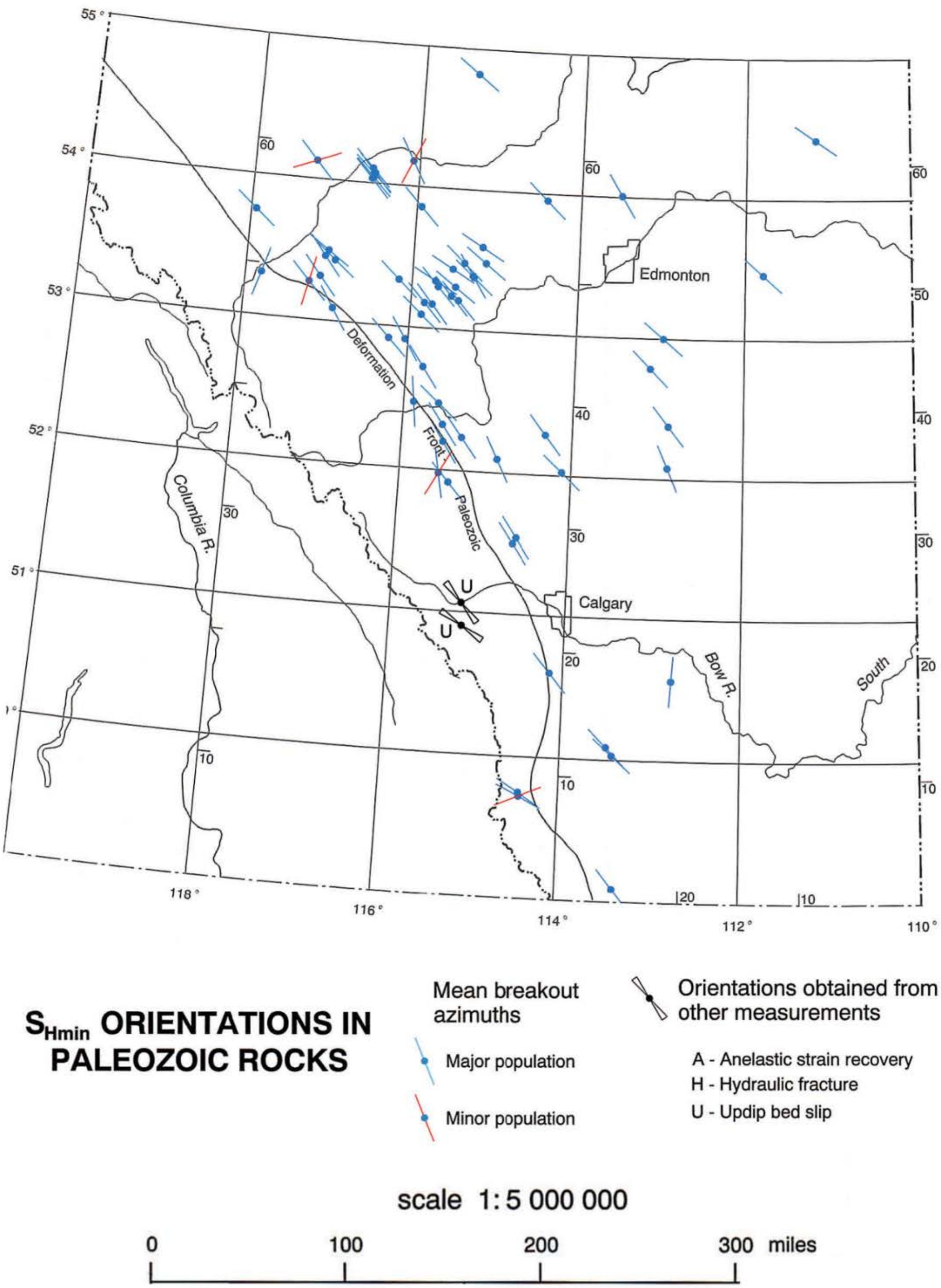


Figure A-11: Example of a Regional Stress Map based on the Orientation of Well Bore Breakouts in Paleozoic Rocks the Western Canada Sedimentary Basin near Calgary.
Modified after: Bell et al. (1994); © Alberta Geological Survey, reproduced with permission.

A5. Information to Support Fault Stability Analysis and Analysis of Confining Zone Integrity

The Class VI Rule, at 40 CFR 146.82(a)(3)(ii), requires owners or operators to determine that any faults or fractures that may transect the confining zone(s) in the area of review will not interfere with containment. The Class VI Rule also, at 40 CFR 146.83(a)(2), requires the owner or operator to demonstrate the presence of a confining zone(s) free of transmissive faults or fractures and that has sufficient integrity to contain the injected carbon dioxide stream and formation fluids. These topics are addressed in Sections 2.3.2 and 3.5 of the guidance. Additional background information is presented here describing various methods that may prove useful to owners or operators. Examples of case studies are also presented.

Fault Stability Analysis

Below are three examples of methods for analyzing fault stability and evaluating the pore pressure that should be maintained to minimize the chances of fault activation.

Failure Plots

Failure plots (Figure A-12) can be used to identify faults within a carbon dioxide storage reservoir that are relatively stable as a function of fault angle. Failure plots are developed by plotting differential stress (i.e., the difference between the maximum and minimum principal stresses, $\sigma_1 - \sigma_3$) versus fault angle, thus identifying conditions that permit fault reactivation (failure) versus formation of new fractures (or relatively stable fault conditions) (Streit et al., 2005). Streit (1999) described the method for constructing failure plots for various rock types and fault strengths. Although the failure plot method has been applied to study sites for carbon dioxide storage, 3D methods should also be used to estimate fault slip tendency (Streit et al., 2005).

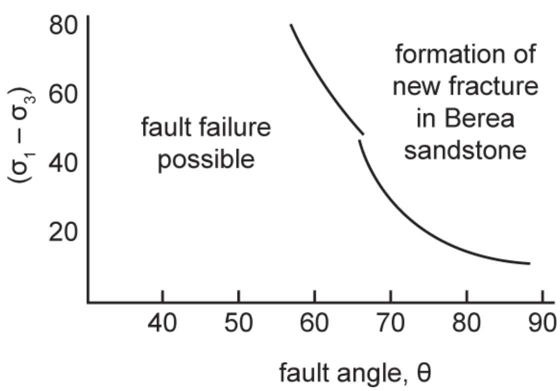


Figure A-12: Example Failure Plot Indicating Scenarios where Fault Reactivation is Possible.
Adapted from: Streit et al. (2005); © Elsevier, reproduced with permission.

3D Fault Slip Tendency

The parameter referred to as slip tendency (T_s) can be used to assess the potential for reactivating a fault associated with carbon dioxide injection (Streit and Hillis, 2004). The fault slip tendency depends upon the effective normal stress, shear stress, and pore fluid pressure. This method can also be used to calculate fault slip tendency along the grid orientation of a fault when 3D seismic surveys are available, and the fault slip tendency can be displayed in 3D graphical form using commercially available software (e.g., TrapTester, Badley Geoscience Ltd, UK, http://www.badleys.co.uk). Figure A-13 is an example fault slip tendency image in 3D form.

The fault slip tendency equation provided by Streit and Hillis (2004) can be used to predict the maximum sustainable pore pressure to avoid fault reactivation. This estimation may be compared to anticipated (simulated) pore pressure at the fault under the proposed operating conditions. The predicted pore pressure at the location of the fault should be less than the maximum sustainable pore pressure, with a margin of safety to account for uncertainties in both the fault slip tendency calculation and modeling results. The margin of safety will depend upon the precision of the data available and should be discussed in the submission materials.

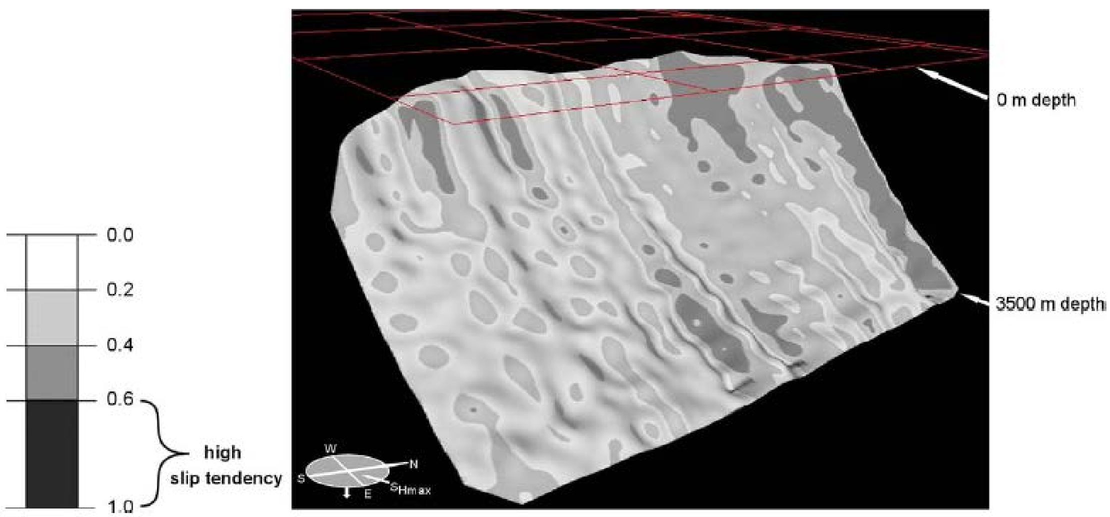


Figure A-13: Example Fault Slip Tendency Image.
From Streit et al. (2005); © Elsevier, reproduced with permission.

Critical Pore Fluid Pressure Increase

The Mohr diagram (Figure A-14) can be used to evaluate the effects of increasing fluid pressure on fault stability (Streit et al., 2005; Streit and Hillis, 2004). The diameter of a semicircle represents the differential stress (σ_1-σ_3), and the curve to the left represents the rock failure envelope. A change in fluid pressure (as indicated by the arrow) can shift the Mohr envelope toward the failure envelope, which indicates a condition of fault failure. In the figure, the decrease in the effective normal stress (from increasing pore pressure or other causes) needed to reactivate an existing fault is indicated by *a*. The additional decrease in effective normal stress needed to create a new rupture is indicated by *b*.

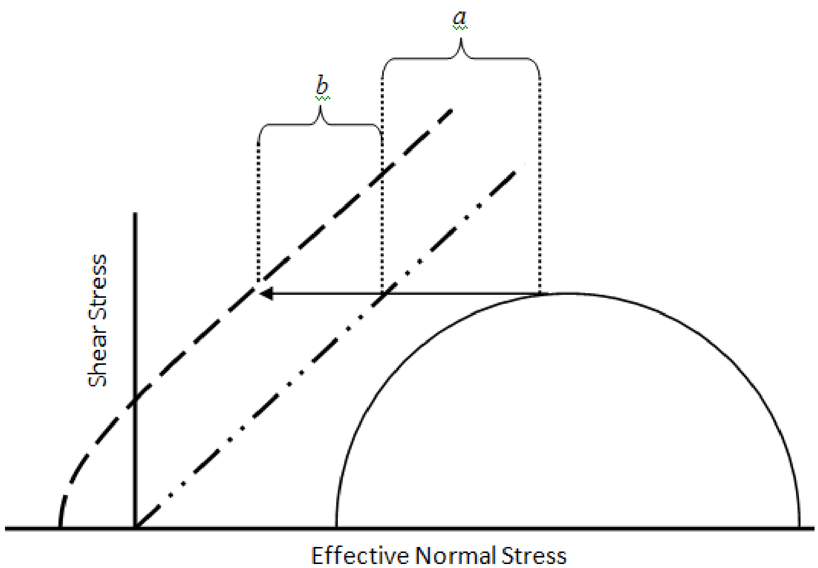


Figure A-14: Example Mohr Diagram.

The maximum injection pressure that can be considered safe and sustainable is site-specific and depends on the seismic history and current state (or pressure-depleted condition) of the site (Benson and Cook, 2005).

Sealing Potential of Faults

Section 3.5.2 of the guidance presents several factors that may be evaluated in order to understand the sealing potential of existing faults; juxtaposition of units, capillary pressure of sediments in the fault zone, catalysis and diagenesis in the fault zone, the SGR, and pore pressure compartmentalization. Below is additional detail on use of Allan charts, calculation of the SGR, and pore pressure compartmentalization.

Allan chart

An Allan chart can be developed from detailed fault geometry (available from maps, cross sections, and other interpretive aids) and a detailed stratigraphic column (developed from well bores, outcrops, and other data). The quality of an Allan chart is highly dependent on data quality, especially if layers are thin or when uncertainties in the amount of displacement along the fault may make it difficult to obtain a good understanding of juxtaposition. Leakage may still occur along the fault even when juxtaposition of permeable/impermeable units across the faults successfully limits the lateral migration of carbon dioxide.

Figure A-15 shows an example of heterogeneity across a fault plane. The area has layer-cake stratigraphy on either side of the fault. In the figure, the footwall and hanging wall boundaries are indicated by solid lines; the vertical exaggeration is a factor of five. The area that juxtaposes potentially conductive units is shaded, with the colored region showing the SGR (see below), which is one indication of sealing potential. Note that the SGR changes dramatically over the surface of the fault. It is often more important to determine if the fault is sealing or non-sealing in the area or areas that have a critical impact on the integrity of the seal (e.g., above or below structural spill points) than for the entire surface of the fault.

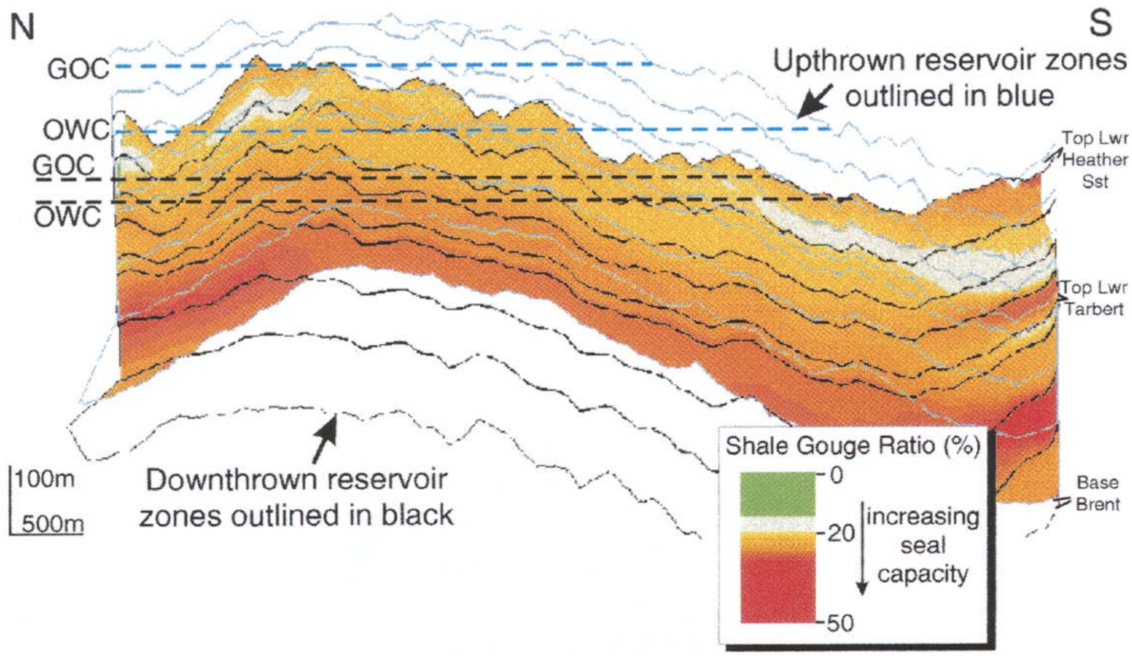


Figure A-15: An Isometric View of a Fault Plane.
GOC=Gas-Oil Contact, OWC=Oil Water Contact. From: Freeman et al. (1998); reproduced with permission from the Geological Society: London.

Shale Gouge Ratio

In Figure A-16, the fault crosses shale (gray) and sandstone (white) layers. As displacement occurs along the fault (*a* and *b*), portions of the shale layers are incorporated into the fault zone. As the displacement increases (*c*), the amount of shale along the fault thins. The direction of fault slip is indicated by arrows, and the fault plane is idealized as a dotted line.

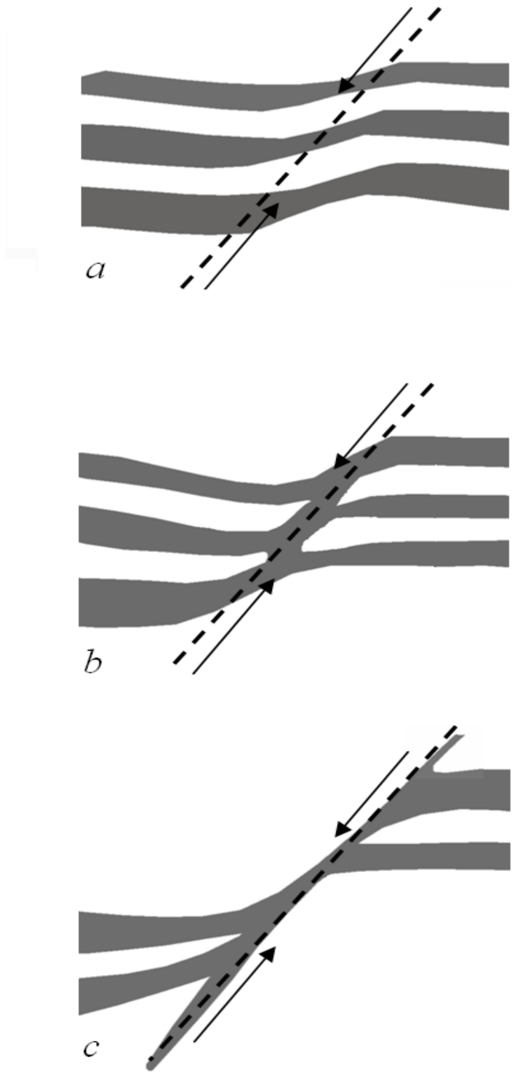


Figure A-16: Simplified Shale Smearing Along a Fault.
Modeled after Koledoye et al. (2003).

Pore Pressure Compartmentalization

Using this method, it is also possible to evaluate if sealing behavior changes along the fault (Figure A-17). In the figure, faults are interpreted in the seismic image in (A), then mapped as lines onto the pore pressure determination (B). The color ramp is from low pressure (green) to high pressure (red). While the major fault (labeled with arrow Y and Z) at right compartmentalizes pressure, indicating that it may be sealing, the fault at left (labeled with arrow X), does not separate regions of different pressure, suggesting that it may not be sealing. The apparent non-compartmentalization of high pressure near the tip of the Z arrow may be due to poor resolution of the pressure data. Vertical red lines above X and Z are assumed to be wells.

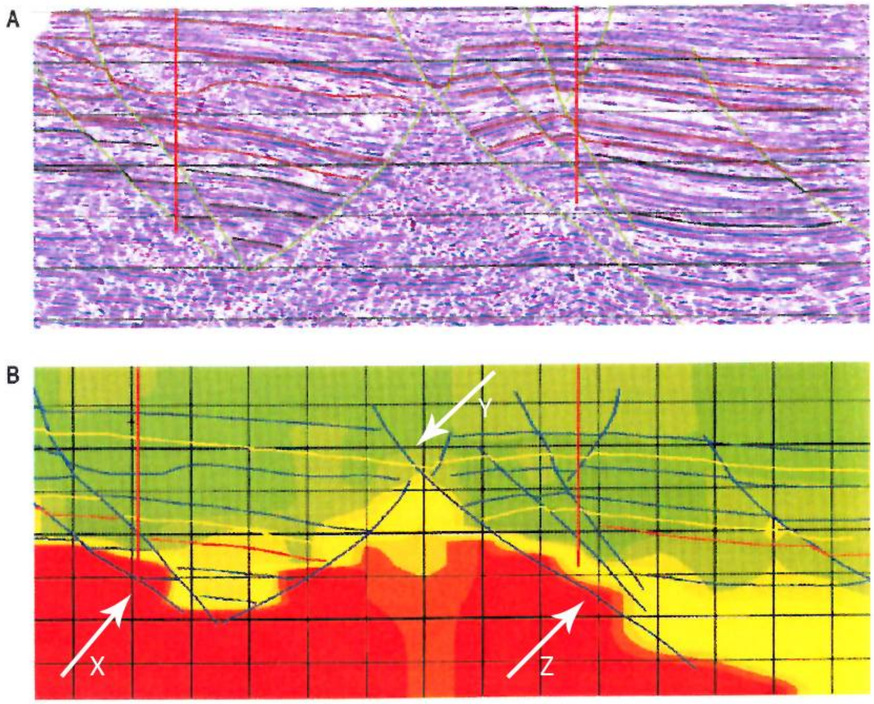


Figure A-17: Sealing Capacity from Seismic Pore Pressure Images.
From: Huffman (2002); © AAPG, 2002. Reprinted by permission of the AAPG, whose permission is required for further use.

Case Studies and Applications

This section provides example applications of geomechanical characterization studies for helping to predict any potential impacts of carbon dioxide injection on fault stability and confining zone integrity as required by the Class VI Rule at 40 CFR 146.83(a)(2).

Fault Stability Case Studies

Chiaramonte et al. (2008) evaluated the fault slip potential of the injection zone for the Teapot Dome oil field to determine the risk of leakage through the fault. The authors also conducted a critical pressure perturbation sensitivity analysis to understand possible impacts of horizontal stress estimates (S_{Hmax} and S_{hmin}) and faulting environments on the probability of fault slip potential. Their study illustrates the potential for using geomechanical modeling to estimate the pore pressure required for a fault to slip during a GS project.

Gibson-Poole et al. (2008) summarized a geomechanical assessment of a basin-scale carbon dioxide geological storage system in southeast Australia. Using data and information regarding the site's rock strength, in situ stresses and fault orientation, Gibson-Poole et al. (2008) estimated the maximum sustainable pore pressure and risk of fault reactivation. Results showed large variability due to data uncertainties. The authors recommended additional work (e.g., laboratory testing of tensile and compressive core strength) to reduce uncertainties and constrain the geomechanical model.

Rutqvist et al. (2007) demonstrated the use of two numerical modeling approaches for analyzing geomechanical fault slip (i.e., continuum stress-strain analysis and discrete fault analysis) coupled with fluid flow to estimate the maximum sustainable injection pressure during geological sequestration of carbon dioxide. The results of these two numerical approaches were compared to conventional analytical fault-slip analysis. The authors concluded that the numerical methods provided a more accurate estimation of the maximum sustainable carbon dioxide injection pressure than the conventional analytical method because the numerical models can better account for the spatial evolution of both in situ stresses and fluid pressure.

Confining Zone Integrity Case Studies

Haug et al. (2007) described a geomechanical characterization of a potential carbon dioxide injection site at an existing oil and gas field in Alberta, Canada, which included determination of the principal stresses (S_v, S_{Hmax}, S_{hmin}) and discussion of laboratory testing determinations of rock strength and deformation behavior. The study also included a sensitivity analysis regarding potential success for carbon dioxide containment based on data variability. The authors concluded that laboratory triaxial tests should be conducted to confirm the accuracy of the correlations.

Smith et al. (2009) described the program components of geomechanical testing and modeling of reservoir and confining zone integrity for a carbon dioxide sequestration project at an existing oil and gas field in Alberta, Canada. This work described the overall geomechanical workflow process and provided specific examples of log-derived rock strength and elastic properties, cores used for geomechanical testing, stress versus strain data measured on cores, linear Mohr-Coulomb failure envelopes, rock strength measurements, and uniaxial pore volume compressibility tests. In situ stresses, formation pressures and mechanical properties were input into a finite-differences-based geomechanical simulator to predict conditions leading to deformation of reservoir and confining zone, induced stresses, and to assess the propensity for fault reactivation and movements.

Orlic (2009) discussed the impacts of geomechanical changes in a reservoir associated with pressure depletion and rock compression during hydrocarbon production. Computational modeling examples were used to illustrate the mechanical impact of carbon dioxide injection on confining zone integrity, fault stability, and well integrity. This study illustrates the use of computational modeling for predicting effects of carbon dioxide injection on containment capacity of the reservoir, taking into account previous stresses from depletion.

Rutqvist and Tsang (2002) demonstrated the use of computational modeling to study the geomechanical effects of injecting carbon dioxide into a hypothetical sandstone formation. The authors provided discussion of the rock and fluid input parameters and simulation results assuming a homogeneous confining zone without intersecting fracture zone, and the effects of a vertical fracture zone in the confining zone. The analysis provided a better understanding of possible mechanisms affecting geomechanical changes associated with carbon dioxide injection processes.

A6. Information to Support Geophysical Characterization

To support the requirement at 40 CFR 146.82(a)(3)(iii) to submit data on the injection and confining zone(s), this section provides background information on available geophysical methods that owner or operator may use, including seismic, gravity, magnetic, and electrical/EM methods. This section supplements the information provided in Section 2.3.10 of the guidance, which discusses geophysical characterization.

Geophysical methods gather information about subsurface features in lieu of physically sampling the region of interest. Depending on the scale and resolution of the investigation, geophysical methods may help to provide the required information on the stratigraphy, structure, extent, thickness, porosity, and permeability of subsurface units to be submitted to the UIC Program Director with a Class VI injection well permit application [40 CFR 146.82(a)(1)–(21)]. There are four main types of geophysical methods: seismic, gravity, magnetic, and electrical/EM. These methods can image a large volume of the subsurface without penetrations (i.e., wells or boreholes). These methods can provide good spatial coverage of a project area and may be especially useful in regions where subsurface geology is heterogeneous and/or wells are sparse. Geophysical methods are widely used for subsurface exploration and characterization in the hydrocarbon industry, archeology, engineering, and other fields.

Methods used to characterize sites for carbon dioxide storage will not differ substantially from methods used to characterize subsurface geology for other purposes. The choice of storage formation (e.g., depleted reservoir, coal seam, saline formation, etc.) will not likely strongly influence the suitability of geophysical techniques. Site-specific considerations such as depth, geologic complexity, and overlying lithologies are more likely to influence the choice of methodology. Two notable exceptions to this generalization are seismic methods, for which this technology may be hampered in depleted gas reservoirs, and gravity methods, which work especially well in most brine-filled formations.

The need to characterize features at depth is likely to be the most uniformly limiting factor in selecting an appropriate geophysical method for site characterization. Most carbon dioxide is likely to be stored at a depth of at least 800–1000 m, depending on site-specific conditions, and resolution at depth varies greatly among techniques and among different deployment techniques within the same method. Geophysical methods used primarily to image the shallow subsurface (e.g., ground penetrating radar (GPR), shallow seismic refraction, etc.) are not discussed in this section.

Overview of Geophysical Techniques

Data gathered with geophysical techniques may aid in the creation of geologic maps and cross sections that illustrate the regional geology, hydrogeology, and geologic structure. Table 2-1 of the guidance summarizes the types of data produced by the various methods.

The different geophysical methods vary in quality, the surface and subsurface environments in which they can be used, and the types of data they produce. For example, unlike other geophysical methods, seismic data may allow estimates of pore pressure in the injection formation, confining zone(s), and other zones.

Lithology and rock properties cannot be determined solely using geophysical data. Data gathered from geophysical surveys can indicate certain lithologies but are not conclusive. Information from stratigraphic wells, stratigraphic columns, or other sources is required to be submitted to the UIC Program Director with a Class VI injection well permit application. Such information can help to confidently assign rock types and properties to formations imaged using geophysical methods. Some of the required materials (e.g., maps and cross sections, available field data such as well logs) may help in interpreting geophysical data [40 CFR 146.82(a)].

Regardless of the geophysical method type, aerial, surface, and borehole deployments of each method are typically available. There are common advantages and disadvantages to each. Aerial surveys can cover large areas at low cost, they require no site preparation, but they often produce surveys of lower resolution than those produced by surface or borehole methods. Surface methods offer higher resolution in most situations and still offer coverage over a large areal extent. However, cost may be high, especially in areas with topographic relief, infrastructure, and/or environmentally sensitive cultural areas. Borehole methods often offer the highest resolution and can also often be acquired at a low cost. However, they do not image a large volume of the subsurface and they depend upon subsurface penetrations that cross the formations of interest. For all survey types, increasing the density of measurements, sources, or receivers will generally increase the quality of the survey but will also increase cost.

Seismic Methods

A seismic survey uses seismic waves to produce 2D sections or 3D images of the subsurface. Both seismic reflection and seismic refraction techniques are available. Refraction techniques are generally used for imaging shallow features (less than 100 m) and are less useful than reflection techniques for interpreting complex geologic structures. The remainder of this section focuses on reflection techniques. More information on refraction techniques is available in *An Introduction to Geophysical Exploration* (Kearey et al., 2002).

Seismic reflection techniques measure the time it takes for seismic waves emitted from a source to bounce off a subsurface reflector and be detected at a geophone. This method is by far the most established, commonly deployed, varied, and advanced of the geophysical methods. More detailed information on seismic methods and processing is available from numerous sources, including introductory guides such as: *A Handbook for Seismic Data Acquisition* (Evans, 1997), *Environmental Geology – A Handbook* (Knödel et al., 2007), and *An Introduction to Geophysical Education* (Kearey et al., 2002).

Different source/receiver deployment configurations can be used to maximize data quality depending on terrain and other factors (see Short, 1992 for more details). Newer, fully portable (cableless) data acquisition systems are also available (Criss, 2007) and may be used in regions with surface infrastructure and/or rough terrain.

Seismic reflection systems are recognized as having the highest resolution of all geophysical imaging techniques in most situations (Benson and Myer, 2002). Seismic methods work best when characterizing simple, homogenous geologic settings where supplementary sources of data such as well logs, outcrop data, and other geophysical surveys are available. Increasing subsurface complexity may increase survey cost or decrease the resolution of survey results. Areas with accumulations of loose sediments such as thick sands or unconsolidated sandstones, conglomerates, well sorted gravels, or weathered horizons are challenging to image and may require more detailed consideration of seismic source and detector (see Short, 1992 or Knödel et al., 2007 for further information on selecting a proper seismic source). Seismic surveys are also complicated by noise contamination from roads, airports, railroads, mines, and other human activities that cause mechanical vibration.

Difficulty also increases when imaging through salts, basalts, coal seams, carbonates, and non-sedimentary units (Cooper, 2009; Hyne, 2001). Non-clastic rocks (i.e., metamorphic or igneous rocks) and coal seams cannot be imaged well. If such lithologies are present in the area of interest, seismic data may need to be supplemented with additional data. For example, if salt bodies are present, gravity data can be co-analyzed with seismic data to accurately determine their size and location (Nester and Padgett, 1992). Basalts pose a problem for seismic methods because traditional seismic approaches have resulted in severe energy scattering and wave interference. Some success has been reported in imaging basalts using multicomponent systems and wave component analysis (Sullivan et al., 2008). Carbonates often have minimal changes in seismic properties even when there are changes in texture, permeability, and porosity. High quality surveys, multicomponent methods, or other additional data collection steps may be needed to obtain sufficient accuracy and resolution in difficult environments.

Both surface and subsurface seismic methods can use additional wave types to improve data quality. Most seismic data acquisition systems collect only p-wave (compressional wave) data unless otherwise specified, usually in two vibrational directions (called components). Other seismic wave types and components may also be collected to improve survey results. Special sources, receivers, and recording capacity are usually the only changes required to modify a seismic survey for additional wave types. Geophones that measure additional seismic components (such as direction of vibration) may also be added. The main disadvantage of these methods is that they increase processing time and are not as well-developed as standard approaches.

Wave choice depends largely on subsurface geology. P-waves remain the best option for imaging bulk changes such as porosity. However, p-waves are distorted by gases in rock. In such cases, shear waves (s-waves), which are not distorted by subsurface gases, can be used (Thompson, 2005). This may be advantageous when characterizing some depleted gas reservoirs for carbon dioxide storage. S-waves are also appropriate for heavily faulted or fractured sites due to their greater sensitivity to continuous features such as fractures. Stoneley waves can help to identify fractures and changes in permeability (Cheng, 1992). Because s-waves provide information in the waveform as well as in the arrival time of the wave, a smaller number of geophones may be needed to gather the same amount of information.

S-waves can also help improve seismic pore-pressure prediction. S-wave data can aid in determining which seismic velocity variations are due to variations in fluid content and which are due to variations in fluid pressure (Sayers et al., 2000). In complex areas such as shallow, grossly undercompacted sediments, zones of severe unloading with minimal effective stress, and areas near gas chimneys and clouds, s-wave data may also help improve results (Huffman, 2002; Thompson, 2005).

Seismic Deployments

Seismic data can be collected with many different source/receiver configurations. Deployment can be done on the surface, in boreholes, or in a combination of both. 2D and 3D seismic profiling are the leading options available for surface-based seismic imaging. 2D surveys produce "slices" of the subsurface while 3D surveys produce subsurface models that can be rotated and viewed from different perspectives. 2D seismic surveys are less expensive than 3D surveys because they require less site preparation, shooting time, and post-collection data processing. The chief disadvantage of 2D imaging is that, because it is collected in a line on the surface, it is difficult to determine the location of out-of-plane features. Therefore, 2D surveys are not optimal in settings where significant lateral heterogeneity is expected (e.g., areas with salt domes, intrusions, or where sedimentary layers are expected to thin or thicken). Application of 2D seismic profiling may also be problematic in faulted regions, where the choice of line orientation is more critical to capture faults. 3D surveys are preferable to 2D surveys when characterizing sites with complex or variable subsurface geology, where subsurface geology is not well constrained, where improved resolution or greater certainty in subsurface characterization is needed.

Both 2D and 3D seismic methods have been used at GS sites. 2D seismic surveys were used for site characterization and baseline data at the Sleipner project in the North Sea (Hellevang et al., 2005). The Weyburn project in Saskatchewan, Canada also used 2D seismic lines for site characterization and as baseline measurements (Wilson and Monea, 2004). 3D seismic surveys were used for both site characterization and as baseline data at the carbon dioxide storage by injection into a natural saline aquifer project at Ketzin, Germany (CO2SINK) and for site characterization at the Kallirachi oil field in Greece, which is being considered for EOR/carbon dioxide storage (Koukouzas et al., 2009).

A larger number of downhole seismic techniques are available. VSPs are the most common borehole seismic method. A VSP is conducted with one component located on the surface (usually the source) and the remaining component placed downhole. A VSP can be conducted in a vertical or deviated well to a depth of at least 3,000 m (Balch et al., 1982). The source may be directly adjacent to the borehole or, for an offset VSP, located at a fixed distance away. A VSP can resolve features 3–4.5 m in size or smaller.

A VSP can also help increase the resolution and accuracy of other seismic surveys. First, a VSP can provide an accurate determination of the seismic velocity within the area of interest (seismic refraction techniques can also provide this information in simple geologic settings). This determination can help with seismic migration and pore pressure estimation. A VSP can also help confirm the depth at which upgoing reflections are generated, which can be used to link geology derived from other bore logs to seismic attributes (Kearey et al., 2002).

Crosswell seismic methods deploy sources and receivers in different wells, producing a survey that images the plane between the wells. The Ketzin project used crosswell surveys and VSP surveys for site characterization and baseline monitoring data. Crosswell surveys between multiple wells can be used to produce a fence diagram. Equipment is generally deployed in monitoring wells located within 500 m of each other (Hoversten et al., 2002), although deployment down active injection wells is also possible (Daley et al., 2007).

Crosswell seismic surveys combine most of the advantages of VSP with additional lateral extent. Crosswell seismic profiling can achieve a maximum resolution of 3 m (Harris and Langan, 1997), which may provide data 10–100 times more detailed than surface seismic data (Martin et al., 2002). Crosswell seismic profiling may also be the best option available for imaging thin beds. The data can be used to fill the resolution gap between high-resolution well cores and 3D surface data (Washbourne and Bube, 1998) or to help correlate structures between well bores. However, because of the need for multiple wells, crosswell seismic profiling will not be suitable in areas that do not already have abundant subsurface penetrations. Furthermore, the distribution of wells will determine the potential planes for crosswell imaging. These orientations may not be optimal for imaging the relevant features. Crosswell imaging was used successfully for both site characterization and baseline monitoring at the Nagaoka pilot project in Japan, which injected and monitored 0.01 megatonne (Mt) of carbon dioxide.

The borehole microseismic method relies completely on subsurface deployment and uses passive seismic energy. A string of geophones is deployed down a monitoring well and used to sense seismic events, typically on the order of M -3 to -1. Microseismic events can be detected up to 1 km from the well on average (Downie et al., 2009). The period of data collection is variable and depends upon the frequency of seismic events, but typically lasts from several weeks to several months. This is disadvantageous compared to other seismic methods that collect data over a period of hours. Generally, the greater number of microseismic events, the more accurate the result.

After collection, the hypocenters of the seismic events are projected onto a subsurface map to image fracture networks, faults, and other regions actively undergoing strain or deformation. The quality of the geologic model used to transform the time data and locate each hypocenter largely controls the accuracy of the result (Warpinski et al., 2009).

Processing of Seismic Data

Post-collection processing techniques provide control over the final quality of the survey and its applicability to the project site characterization. In some cases, old data may even be re-processed with newer techniques to uncover additional information. Choice of processing techniques will largely depend on site-specific factors other than the type of carbon dioxide storage reservoir being investigated. For example, certain types of processing (such as pre-stack migration) are more appropriate in regions where steep faults or other features are anticipated (such as near salt domes). Seismic processing techniques are immensely varied; the following is an overview. For more detailed information, a number of handbooks on seismic processing are available (e.g., Upadhyay, 2004).

If information about faults or other discontinuities in the subsurface is desired, special processing techniques can be used to mine the data for this information. Seismic crustal anisotropy processing can be used in areas where aligned fractures, joints, or fluid inclusions recur in the subsurface at a distance smaller than the wavelength of the seismic wave. As the wave passes through such a region, it is split into two waves with different polarization and velocities (Crampin and Lovell, 1991), in a manner similar to the effects of diffraction gratings on light waves. Studying the split waves can reveal information about the magnitude, consistency, and orientation of recurring subsurface features. Alternatively, p-wave data can be processed with a technique called p-wave amplitude variation with offset and azimuth (abbreviated pAVAZ or pAVOA) (Gray et al., 2002) to reveal information about fracture and pore orientations. However, these techniques are not fully developed. These techniques may have the potential to be adapted to image cleats and other discontinuities common in coal seams or columnar joint in basaltic flows if either type of formation is used as a potential carbon dioxide reservoir.

Coherence processing can be used to detect faults. This method suppresses continuous features and highlights discontinuities, such as faults, within seismic sections. Although discontinuities in high-quality seismic data are often indicative of faults and lithologic breaks, discontinuities in low-quality seismic data may be due to a range of data collection and processing errors. As a result, coherence is very sensitive to the quality of input seismic data and is not suitable for low-quality surveys.

Other advanced processing techniques, such as difference analysis with data normalization (DADN) (Onishi et al., 2009) are also available.

Pore Pressure Interpretation

Seismic data can be processed to remotely determine subsurface pore pressures. This is accomplished using the relationship between pore pressure and effective stress:

pore pressure = total stress (i.e., overburden stress) – effective stress

Any seismic data that yield an accurate velocity for the seismic wave in the subsurface can be used to approximate effective stress. However, not all seismic data meet this criterion because accurate velocity values are not needed to image the subsurface. Ensuring that seismic data can also be used for pore pressure prediction may not greatly increase the survey cost, but it does require planning.

Once accurate velocity data have been obtained, numerous methods are available to convert velocity to pore pressure. These methods tend to work best in developed basins filled with shales and sands. In regions with high sedimentation rates like the Gulf of Mexico, tectonically complex regions, or regions with abundant carbonates, the transforms to convert velocity to pressure may introduce significant error. (See Sayers et al., 2005; Young and Lepley, 2005; and Sayers et al., 2000 for more information.)

The overburden pressure in the area of interest is needed for accurate pore-pressure determination. The overburden pressure is closely related to the density of the overlying material and can be determined from well density logs. Gravity measurements can also be used to estimate the overburden pressure (Huffman, 2002). This is especially advantageous in areas with complex geology (e.g., regions with salt domes or other intrusive structures) where individual boreholes are likely to miss significant features.

Under optimal conditions, pore pressure analysis can resolve pressure data for strata 30–60 m thick at medium depth in clastic basins with relatively simple stratigraphy (Huffman, 2002). Pressure information can also be used to help determine the integrity of sealing layers and the sealing behavior of faults (Huffman, 2002; Sayers et al., 2002). Additionally, if pore pressure appears compartmentalized by a fault in a 3D subsurface pressure map, this may support the interpretation that the fault is sealing. Subsurface pressure data may also help to inform estimates of risks associated with induced seismicity and estimates of total storage capacity, both of which require estimates of subsurface pressure.

The main disadvantages to this technique are the extensive data processing and interpretation, which may introduce large errors, and the need for basin-specific correction factors during velocity processing. Saline formations and depleted reservoirs are the storage formations of interest where a potential Class VI injection well applicant would be most likely to utilize this technique.

Additional Seismic Data Analysis - Seismic Stratigraphy

Seismic stratigraphy identifies stratigraphic units based on their seismic characteristics. Because seismic reflections follow large-scale bedding, the geometry of the reflections allows the delineation of features such as unconformities, depositional sequences, and unit thicknesses. Seismic reflections will not indicate facies shifts, but can show fluid changes or diagenetic changes (Emery and Myers, 1996). The principles of seismic stratigraphy are presented in a classic paper by Vail et al. (1977).

Stratigraphic features identified in seismic surveys can be integrated with lithologic data from cores, well logs, and other data to allow interpretation of depositional environments. Lithologies and other characteristics identified at wells and boreholes can be correlated to seismic attributes, which can then be used to predict subsurface properties at other locations through the use of neural networks, regression, or other methods. Stratigraphic features identified in this manner may help in identifying features (e.g., barriers, channels, fans) that might affect storage capacity and migration of carbon dioxide.

There are different processing and display options that can be employed for stratigraphic interpretation, and the choice of method will depend upon acquisition parameters, seismic sources, and site geology (Emery and Myers, 1996).

Gravity Methods

Gravity-based methods image differences in density among subsurface materials. Because density is related to gravity, changes in the distribution of fluids, cementation, and porosity of subsurface materials can be measured as changes in gravity. Gravity data can be collected from land-based stations, aerially, or directly from the subsurface using boreholes. Choice of deployment is usually controlled by factors such as desired resolution and site-specific geology and is not limited by choice of carbon dioxide storage formation type.

Gravity is measured with a gravimeter; information on how measurements are obtained can be found in Paterson and Reeves (1985). Figure A-18 is an example of a typical surface deployment pattern.

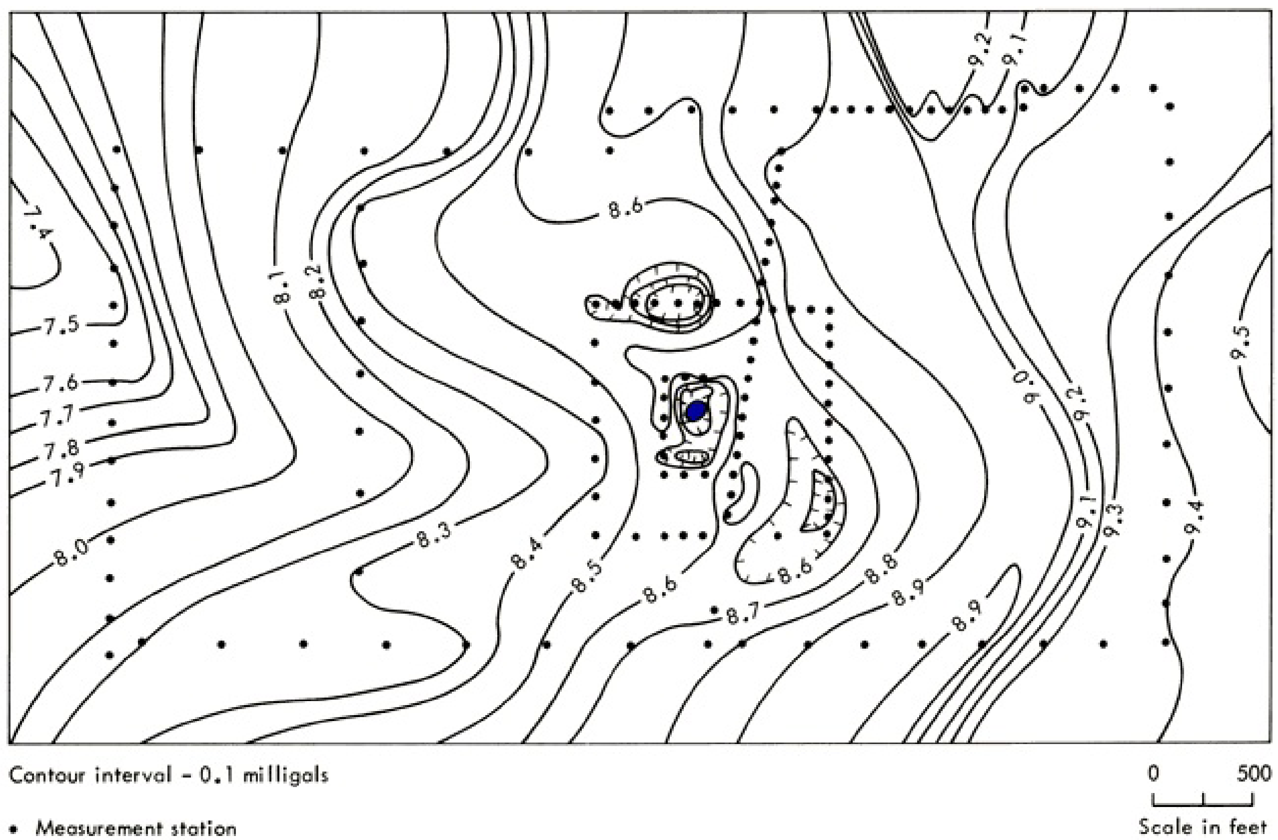


Figure A-18: A Gravity Map of an Area Ore Deposit and Mine.
From: Yarger and Jarjur (1972); Reproduced with permission from the Kansas Geological Survey.

Because detection of faults and structural features using gravity data depends upon contrasts in density, gravity methods work best in basins with varied lithologies. Salt domes and igneous intrusions are the easiest types of lithologic features to image because they usually have a high-density contrast with surrounding formations. Figure A-18 illustrates the gravity anomaly associated with an ore deposit and mine. Faults may be detected with gravity data if units with contrasting density or regions with different sedimentary thicknesses are juxtaposed. Small faults or faults with large displacement occurring in discrete steps are more difficult to detect with gravity data than large planar faults. Vertical faults are especially difficult to detect using surface gravity methods (Barbosa et al., 2007).

Because gravity measurements are not unique to specific lithologies, additional data from other types of geophysical surveys or other sources (e.g., boreholes, outcrops) can greatly improve the interpretation of gravity data (Jordan and Hare, 2002). One advantage relative to seismic data is that, because processing of gravity data is much more straightforward, it generally introduces much less interpretive error.

Aerial and Surface Gravity Methods

For aerial methods, data are typically collected along parallel lines in the area of interest. Closer spacing will generally increase resolution. For surface deployments, measurements are typically taken at discrete stations across the area of investigation. Broad gravity surveys may suffice for detecting large-scale changes in the thickness of basin fill and other basin-wide features, while more detailed surveys will be needed to detect finer features such as the distribution and thickness of specific formations.

Borehole Gravity Methods

Borehole surveys can be used to determine layer thickness and aid in determination of lithologic composition. Borehole gravity methods collect information from a larger subsurface volume than other types of borehole logs. This is useful for characterizing porosity and other formation parameters in carbonate and fractured reservoirs (LaFehr, 1992; Chapin and Ander, 1999) or other situations where poor borehole conditions, problematic casings, cementing problems, and well bore washouts are likely to affect the quality of other borehole formation-testing tools (LaFehr, 1992).

Borehole gravity surveys are conducted in a manner similar to borehole seismic surveys. A gravimeter is lowered down the borehole and measurements are taken as the device is raised, usually at set intervals between 3 m and 15 m (Herring, 1990). Borehole surveys have been conducted in wells 2,000 m deep (Seigel et al., 2009) and inclined up to 60 degrees (Seigel et al., 2009). Resolution is usually high. Special techniques (i.e., gravity gradiometry) are needed to characterize non-horizontal strata.

In regions that are laterally variable geologically, borehole gravity data may indicate features such as salt domes and reefs even if they do not intersect the borehole (LaFehr, 1992). As a rule of thumb, borehole gravity surveys can detect anomalies as far away as one to two times the height of the body in question. For example, a sandstone lens 50 m high could be detected 100 m from the well bore under good conditions (Herring, 1992). When using a single well, however, it is only possible to know the radial distance from the well of a feature and not the direction.

Electrical/Electromagnetic Geophysical Methods

Electrical and EM methods use the conductive properties of subsurface materials to infer fluid distribution, stratigraphy, and/or structural information. Data can be collected aerially, surficially, or from the subsurface. Electrical/EM methods can use either natural electric fields or a controlled source (man-made). Deployment of survey equipment may either be temporary (for one survey) or permanent (e.g., installed during well construction).

Electrical methods transmit a pulse of electrical energy into the subsurface using electrodes or other means; changes in properties such as galvanic potential that are registered when the signal arrives at a receiver are used to infer subsurface resistivity, which is then mapped and interpreted. EM methods measure the induction effect (generation of current and electric fields) in the subsurface by another EM field or electric current (Jordan and Hare, 2002). Depending upon the method, results can be presented either as a surface map or cross section. Figure A-19 provides an example of the end result from an EM survey.

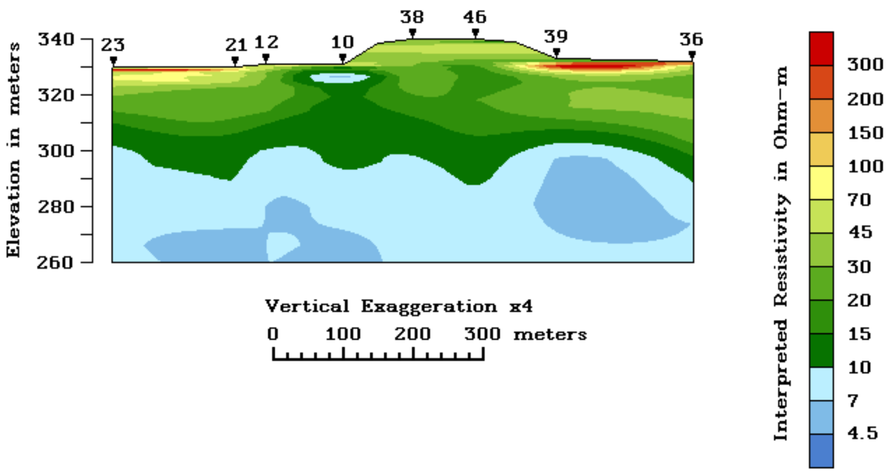


Figure A-19: A Subsurface Cross Section of Electromagnetic Resistivity Data.
From: Lucius and Bisdorf (1997).

Fluid saturation and composition are the two most important factors controlling the conductivity/resistivity in the subsurface and, accordingly, the response to electric and EM fields. Therefore, electrical and EM methods are most sensitive to fluid composition, distribution, and saturation and less responsive to lithologic or structural changes (Wynn, 2003). Detailed determination of subsurface lithologies or structural features is usually only possible when the flow and distribution of formation fluids are controlled by lithology and structure. For example, fractures and faults are generally considered significant for electric/EM studies in low permeability and low porosity formations, where they can act as the primary pathways for conductive fluids (Orange, 1992). Accordingly, electrical/EM data are more likely to be used to characterize saline formations and depleted reservoirs than other types of potential carbon dioxide storage formations. Interpretation of electrical data is primarily qualitative and generally attempts to explain the shape of an anomaly in terms of fluid flow direction and magnitude (Orange, 1992). Values such as flow volume and composition cannot typically be quantified.

Deployment method is more strongly influenced by the desired resolution than the type of carbon dioxide storage formation. Most surface methods for electrical data collection yield poor results compared to subsurface methods because surface conditions are highly heterogeneous and tend to attenuate the signal (Wilt et al., 1995). Near-surface changes in saturation (e.g., from rainstorms) can also greatly affect survey results, although this is more problematic for time-lapse monitoring than site characterization.

For subsurface deployments, the survey depth is typically two to three times the length of the dipole used to generate the current (Jordan and Hare, 2002). Resolution is usually 5–20% of the electrode depth (Jordan and Hare, 2002). Resolution is low for most electrical/EM methods compared to seismic methods. However, the depth and breadth of electrical/EM surveys can provide valuable information on the regional geologic framework at low cost (Orange, 1992).

Highly conductive and magnetic rocks may introduce error into electric/EM methods (Jordan and Hare, 2002). Additional care should be taken if magnetite, iron-rich sands, graphite, or other conductive and/or magnetic constituents are present (at levels as low as 1%) within the area of interest. For further information, Jordan and Hare (2002) and the U.S. Army Corps of Engineers (1995) provide a detailed discussion of electrical and EM methods.

Natural Source Electrical/Electromagnetic Methods

The self-potential (SP) method is an electrical technique that detects the current (in millivolts) generated by electrochemical reactions (i.e., oxidation/reduction reactions) in the subsurface (Orange, 1992). Measurements should not be taken within 500 m of power plants, substations, pipelines, telephone lines, or power lines (Jordan and Hare, 2002). The result is a surface map of electric potential. (see U.S. Army Corps of Engineers, 1995, for further details on SP surveys.)

Magnetotellurics is an EM method that measures resistivity in the subsurface based on the strength and wave impedance of naturally propagating low-frequency EM fields in the Earth (Orange, 1992). Data are usually displayed as a cross section. Magnetotelluric surveys can image 10 km or more into the subsurface (Orange, 1992), allowing deep structures to be identified. Rock types can also be inferred when resolution is high and an existing knowledge of regional stratigraphy is available.

Methods that use naturally occurring electric fields avoid the expense and logistics of choosing and operating a source. However, naturally occurring fields are unpredictable, and the total energy level of the field cannot be controlled (Orange, 1992).

Controlled Source Electrical/Electromagnetic Methods

Controlled source methods use external sources to generate electrical energy and direct it into the subsurface or to induce EM fields in the subsurface. These methods can image the subsurface up to 1–2 km deep (Orange, 1992) with low resolution. Electrical controlled-source methods use a variety of sources channeled into the subsurface using source and receiver electrodes (U.S. Army Corps of Engineers, 1995). Induced polarization (IP) and complex resistivity (CR) are subtypes of this method and are most often used in known hydrocarbon reservoirs (Orange, 1992).

Electrical methods can also be used in a crosswell configuration. One such technique is electrical resistance tomography (ERT). Deployment is similar to crosswell seismic imaging with a source of electric current in one well and a receiver in another. Resistivity changes on the order of 30%

can generally be detected, although under optimal conditions resistivity changes as little as 10% can be measured (Newmark et al., 2001). Figure A-20 presents an example permanent downhole ERT array used to characterize and monitor carbon dioxide injection into a depleted reservoir.

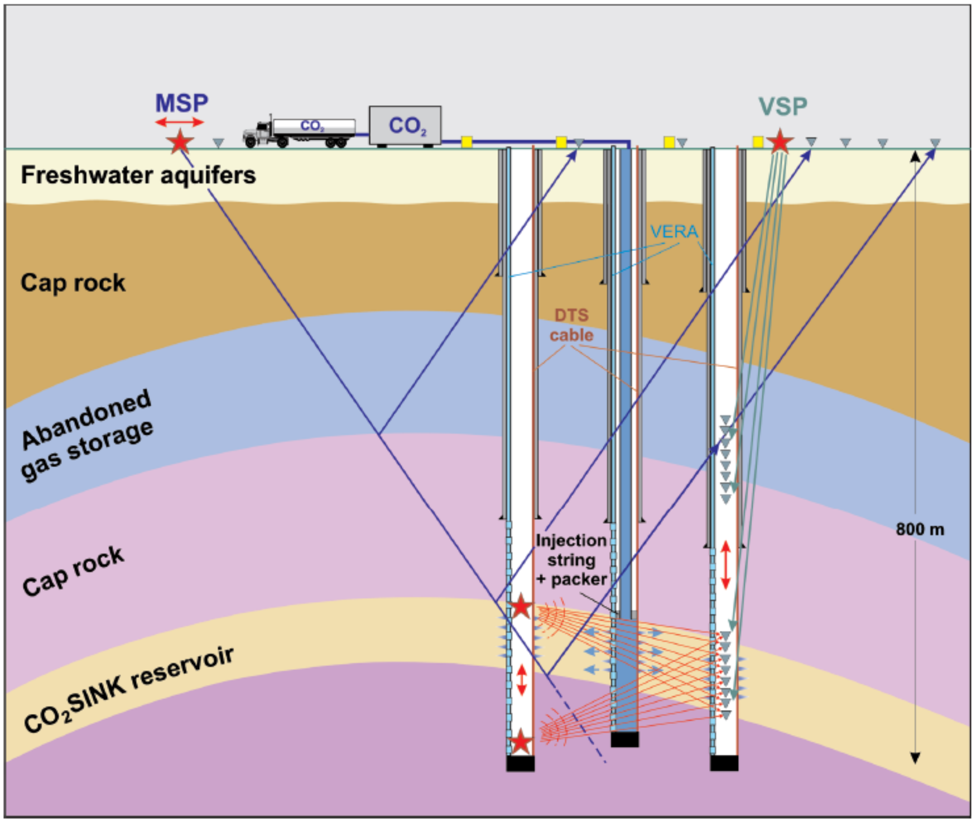


Figure A-20: Permanently Installed ERT Array at the CO2SINK Pilot Site at Ketzin.
The diagram uses blue boxes to represent geophones, while the red star is the source. VSP = Vertical Seismic Profile, DTS = Distributed Thermal Sensor, VERA = Vertical Electrical Resistance Array, MSP = Moving Source Profile. From: Forster et al. (2006); © AAPG 1992, reprinted by permission of the AAPG whose permission is required for further use.

Surface EM controlled-source methods use coils and/or grounded wires to generate an EM field on or above the surface. This field induces currents in the subsurface, which, in turn, generate their own EM fields. The induced subsurface EM fields are then quantified by the disturbance they create in other fields (frequency domain methods) or as they decay (time domain methods). Resistivity can be calculated through inversion and modeling of these measurements (Orange, 1992). EM methods can be used to detect changes down to 1 km or more (Orange, 1992; Jordan and Hare, 2002). Data can be collected aerially, although the maximum depth decreases to 100–200 m when using aerial data collection. Aerial data collection usually cannot resolve anomalies smaller than 50–100 m^2 (Jordan and Hare, 2002).

Controlled source audio-frequency magnetotellurics (CSAMT) is similar to the magnetotellurics method mentioned above, but the EM wave is generated and introduced into the ground by a dipole or pair of dipoles, usually 10-200 m in length (Jordan and Hare, 2002). A linear array of receivers located several kilometers away collects the signal from the subsurface. Data are displayed as a cross section. CSAMT is less affected by infrastructure-related noise than other electrical/EM depth-profiling methods.

Using a controlled source allows the operator to control the source strength and, to some degree, the signal-to-noise ratio. However, because the field is induced, the field geometry is determined and accounted for during processing. This increases the difficulty of the survey and may introduce processing errors. Also, determining the geometry of the field becomes increasingly difficult in geologically complex regions.

Processing of Electrical/Electromagnetic Data

Depending upon the exact deployment, electrical methods require various amounts of post-collection data processing. Advanced processing techniques are also available if high resolution in single or time-lapse studies is needed (Onishi et al., 2009). Processing methods are not affected by the type of carbon dioxide storage formation being investigated.

Magnetic Geophysical Methods

Magnetic methods use natural variations in the Earth's magnetic field to map features at the shallow, sedimentary, and basement levels. The magnetic field is affected by the distribution of iron-bearing minerals in subsurface formations. The distribution of iron-bearing minerals is usually controlled by the occurrence of igneous rocks, the prevalence of mineralization along faults, and the separation of detrital minerals during fluvial and other sedimentary processes.

The type of storage formation is not likely to influence the suitability of magnetic methods for site characterization purposes, although basalts may have a slight affinity for magnetic methods since igneous rocks can have a high content of potentially magnetic minerals.

Magnetic intensity surveys are usually collected aerially using a magnetometer, although ground-based surveys can also be collected using a portable magnetometer. Figure A-21 presents an example of the type of data an aerial survey can provide. Paterson and Reeves (1985) provide a detailed discussion of magnetic methods.

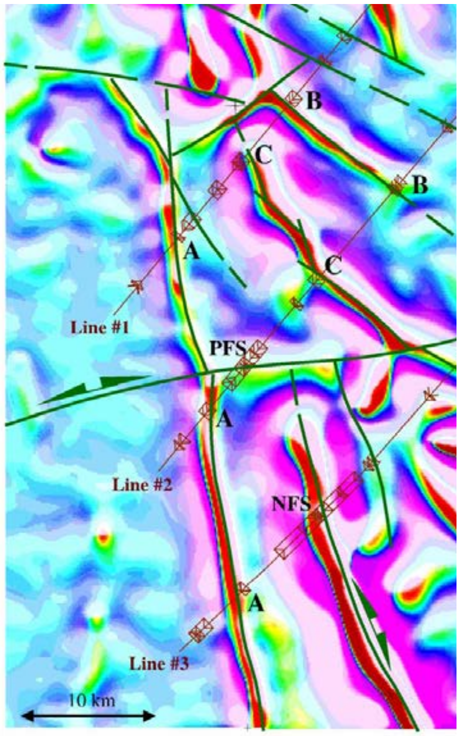


Figure A-21: An Aerial Gravity Map.
The data can then be interpreted for faults (the dashed and solid lines) and other structures. From: Goussev et al. (2004).

Faults and other structural features in both basement rocks and overlying sedimentary cover can be imaged, but formation characteristics are difficult to determine using magnetic data (Ugalde, undated). Faults can be identified either because displacement along the fault juxtaposes units with different magnetic signatures or, more commonly, because secondary mineralization of magnetite or demineralization along the fault plane alters the magnetic signal in the region of the fault. Information on the dip of faults can also be gathered in some cases. One common interpretive error in magnetic surveys is wrongly identifying paleochannels filled with detrital magnetite as faults. Therefore, extra care should be taken in interpreting regions with sandstones and other fluvial lithologies.

Because magnetic data are non-unique and do not represent specific lithologies, additional data from other types of geophysical surveys or other sources (boreholes, outcrops etc.) can improve magnetic data interpretation (Jordan and Hare, 2002). This approach was taken at the Weyburn Project in Saskatchewan. At the site, co-processing of low quality gravity and seismic data allowed positive identification of faults that were ambiguous using either data set alone (Goussev et al., 2004) during site characterization. This data interpretation approach may be a good solution for characterizing areas with vintage data sets such as oil and gas reservoirs.

Magnetic methods are sensitive to human infrastructure. As a result, they are not useful in populated or developed areas because buildings, pipes, and wires obscure the geologic signal. The one advantage to this sensitivity is that magnetic surveys may be used to find abandoned, cased wells. This can help in identifying abandoned wells that may need corrective action, as required at 40 CFR 146.84(c). See the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* for further details on locating abandoned wells and performing the required corrective action activities.

Processing of Magnetic Data

After collection, magnetic intensity data undergo processing. Processing methods are not influenced by the type of carbon dioxide reservoir under investigation. High frequency anomalies can be attributed to near-surface and shallow subsurface effects, intermediate frequency anomalies can be attributed to the composition of the sedimentary basins, and low-frequency anomalies can be ascribed to changes in the basement rocks. Most surveys collected today are of sufficient resolution to detect anomalies in all three ranges.

A7. Information to Support Demonstration of Storage Capacity

To support a demonstration that the site meets the requirement that the injection zone or zones are of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream per 40 CFR 146.83(a)(1), this section provides background on the concept of storage capacity and some of the methods that have been used to estimate storage capacity for different formation types. This section includes definitions of terms, references for information on various parameters, methods for estimating carbon dioxide storage capacity, and case studies. For additional information and recommendations, see Section 3.4 of the guidance, Demonstration of Storage Capacity.

Resources and Reserves

The concepts of resources and reserves are used to estimate the availability of mineral resources (e.g., in the oil and gas and mining fields). Similarly, the concepts of resources and reserves can be applied to carbon dioxide storage capacity. USDOE (2008a) makes a distinction between carbon dioxide resource estimates and carbon dioxide capacity estimates. A carbon dioxide resource estimate is defined as the volume of porous and permeable sedimentary rocks available for carbon dioxide storage and accessible to injected carbon dioxide via drilled and completed well bores. This assessment includes physical constraints, but it does not include economic or regulatory constraints. A carbon dioxide storage capacity estimate is an attempt to realistically include both the physical and economic constraints that determine the volume of rock available for storing carbon dioxide. The level of detail in storage capacity estimates depends on the scale and resolution of the assessment as illustrated in Figure A-22 (Bachu et al., 2007). Storage capacity estimates can be classified by degrees of certainty (Bachu et al., 2007; Bradshaw et al., 2007) as described below and illustrated in Figure A-22.

Theoretical Storage Capacity – This storage capacity estimate results in the least certainty. Bachu et al. (2007) describe it as representing the physical limit of what the geologic system can accept (e.g., entire pore space) or only the space from which the original fluids can be displaced (i.e., pore space minus the irreducible residual saturation of the initial fluid). The theoretical storage capacity typically represents a maximum upper limit to the capacity estimate; however, it is an unrealistic number as in practice there will always be physical, technical, and practical limitations that prevent full utilization of the theoretical storage capacity.

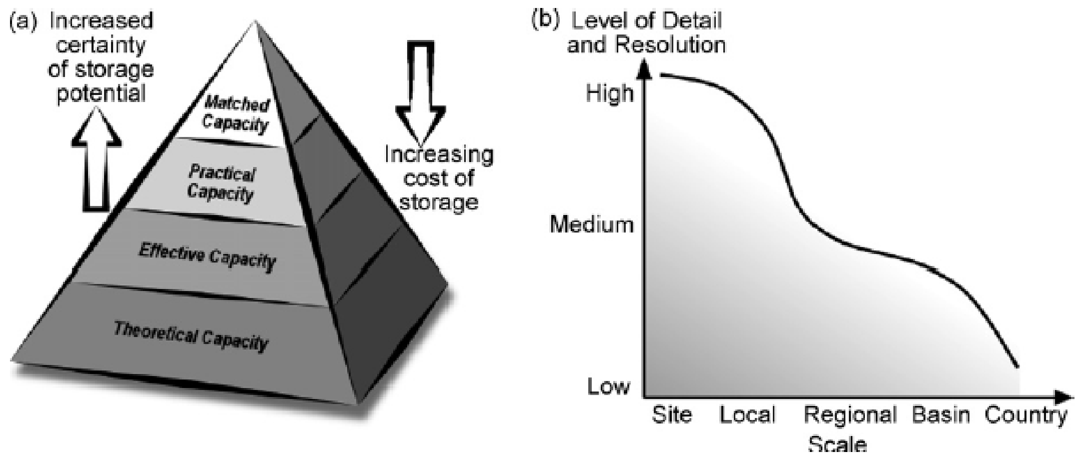


Figure A-22: Variation in Size and Resolution of Various Storage Capacities.
(a) resource pyramid and (b) data and assessment scales. From: Bachu et al. (2007); © Elsevier, reproduced with permission.

Effective Storage Capacity – This estimate is also known as "realistic capacity." Bachu et al. (2007) note that it is obtained by applying a range of technical (geological and engineering) cut-off limits to a storage capacity assessment, which usually changes with the acquisition of new data and/or knowledge.

Practical Storage Capacity – This estimate is also known as "viable capacity." Bachu et al. (2007) describe it as obtained by considering both technical and practical challenges to safe carbon dioxide geological storage. This estimate is prone to changes over the life of a GS project as technology, policy, regulations and/or economics change.

Matched Storage Capacity – This estimate yields the greatest certainty regarding carbon dioxide storage capacity. Bachu et al. (2007) describe it as a detailed matching of large stationary carbon dioxide sources with geological storage sites that are adequate in terms of capacity, injectivity and supply rate.

Additionally, USGS has released a report on risk-based capacity estimates, which differs from the above estimates in that it uses fully probabilistic methods to incorporate geologic uncertainty in calculations of storage potential (Brennan et al., 2010).

This section focuses on some methods that may be used to develop estimates of storage capacity for a GS project with the greatest certainty and highest level of detail.

Parameters and Data Interpretation

This section provides brief information on parameters that may be needed to estimate the volume (or mass) of carbon dioxide storage capacity, depending upon the method selected. Table A-3 provides a summary of the types of methods available for quantifying parameters, such as laboratory methods and field testing, and estimating or predictive tools. Porosity, permeability, and injectivity (flow rate) are discussed in the guidance (Sections 2.3.5 and 4.5.2) and in Section

A3 of this Appendix. Some recommended data sources for determining injection zone thickness, area, and background hydraulic gradient are discussed in Sections 2.3.1 and 2.3.3 of the guidance and Section A1 of this Appendix. Several of these parameters, such as capillary pressure, temperature, compressibility, water saturation, intrinsic and relative permeability, and porosity are also needed for the multiphase fluid modeling required for proposed Class VI injection well AoR delineations [40 CFR 146.84]. For more information on the required AoR modeling for a proposed Class VI injection well, see the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*.

Table A-3: Parameters and Methods for Quantifying Storage Capacity.

Parameter	Methods for Quantifying Parameters			Parameters for Estimating Storage Capacity		
	Labora-tory	Field	Estimation or Prediction	Static Method	Material Balance	Reservoir Simulation
Pressure	X	X	X		X	X
Fracture Pressure		X	X			X
Temperature		X	X			X
Compressibility	X		X			X
Porosity*	X	X		X		X
Permeability*	X	X	X			X
Relative Permeability*	X	X	X			X
Transmissibility	X	X	X			X
Interfacial Tension	X		X			X
Water Saturation	X	X		X		X
Wettability	X					X
Capillary Pressure	X	X	X			X
Viscosity	X	X	X			X
Density and Specific Gravity	X	X	X			X
Mobility and Mobility Ratio			X	X		
Capillary and Gravitational Numbers			X	X		
Injection Zone Thickness, Area and Background Hydraulic Gradient†	X	X	X	X		X
Number of Wells		X	X			X
Skin Factor		X	X			X
Diffusion Coefficient and Dispersivity			X			X
Sweep Efficiency			X	X		

* Covered in Section A3 of the Appendix and in Section 2.3.5 of the guidance.
† Covered in Sections 2.3.3 and 2.3.8 of the guidance.

Pressure

Formation pressure measurements are required by the Class VI Rule as part of the logging, sampling and testing required prior to injection well operation [40 CFR 146.87(c)]. Information on obtaining pore pressure measurements is provided in Section A4 of this Appendix. Additional information regarding types of pressure transducers is available in Harrison and Chauvel (2007) and from commercial manufacturers as well as in the *UIC Program Class VI Well Testing and Monitoring Guidance*.

Fracture Pressure

Field methods such as step rate tests (see Section 4.4 of the guidance) can provide the required calculated information about the fracture pressure of both the injection and the confining zone(s) [40 CFR 146.87(d)(1)] that will support injection pressure limits in the Class VI permit. As noted by USDOE (2008a), all geological formations will begin propagating fractures upon reaching a threshold pressure; this site-specific threshold-pressure constraint is an important consideration in estimating carbon dioxide storage capacity.

A step rate test is performed by first shutting-in the well long enough for the bottom hole pressure to reach equilibrium with the formation pressure. This can be done by using a downhole pressure gauge with a surface readout and watching the gauge until the pressure stabilizes. Theoretical calculations of the time required to reach equilibrium are also available. A fluid is then injected at a constant rate while the downhole pressure is measured. The injection rate is held constant for a period of time that depends on the formation permeability. A typical injection step would be 1 hour for low permeability formations (less than 5 mD) and ½ hour for permeable formations (greater than 10 mD) (USEPA, 1999). After one injection step is completed, the injection rate is raised and another step is conducted. The pressure increments should be great enough to yield measurable pressure differences in the well and should cover the entire planned injection range. Injection rate is plotted versus pressure. The plot should initially be linear. Injection steps are continued until at least two data points are gathered past the point where the plot shows deviations from the linear trend; the intersection point of the two curves is the fracture pressure. After the last injection step, the well is shut-in again and the instantaneous pressure is recorded.

Temperature

Temperature sensors include mechanical (obsolete), thermistors (semiconductor material and highly sensitive), and resistance temperature detectors (wide temperature range and excellent accuracy). Prensky (1992) has described the determination of formation temperature and temperature gradients by the two-point or multiple-point average temperature gradient, whereby a linear relationship is assumed between the ambient surface temperature and the bottomhole temperature. Regression techniques can be used to calculate geothermal gradients for large data sets (Speece et al., 1985). Information regarding local and regional thermal gradients can also be obtained from reports generated by academic institutions and government agencies such as Nuccio and Condon (1996). The reader is referred to Bachu and Haug (2005) and Harrison and Chauvel (2007) for additional discussion and examples.

Compressibility

Rock compressibility data for a given reservoir can be obtained from laboratory measurements on core samples. In situations where laboratory analysis is not practical, rock compressibility values can be estimated from porosity overburden pressure as described by Craft and Hawkins (1959). Harrell and Cronquist (2007) provide a substitute correlation for estimating rock compressibility that depends on rock properties. Other values of rock compressibility have been reported as case studies in the literature (e.g., Law and Bachu, 1996; Ross et al., 2009).

For carbon dioxide, equation-of-state models have been developed to predict carbon dioxide compressibility in multi-component two-phase systems (Firoozabadi et al., 1988). The compressibility of carbon dioxide can also be affected by SOx and NOx impurities, potentially affecting the estimated volume of carbon dioxide for storage; the reader is referred to Benson and Cook (2005) and Sass et al. (2005).

Transmissibility

In the field, vertical permeability (or transmissibility) can be estimated by transient tests generally classified as vertical interference testing or vertical pulse testing (Earlougher, 1977). For these types of tests, part of the well may be used for injection and part of the well may be used for pressure observation as illustrated in Figure A-23. Earlougher (1977) described several applications of vertical testing using type-curve matching methods. Additional discussion of pressure testing and analysis in gas injection wells is provided by Matthews and Russell (1967).

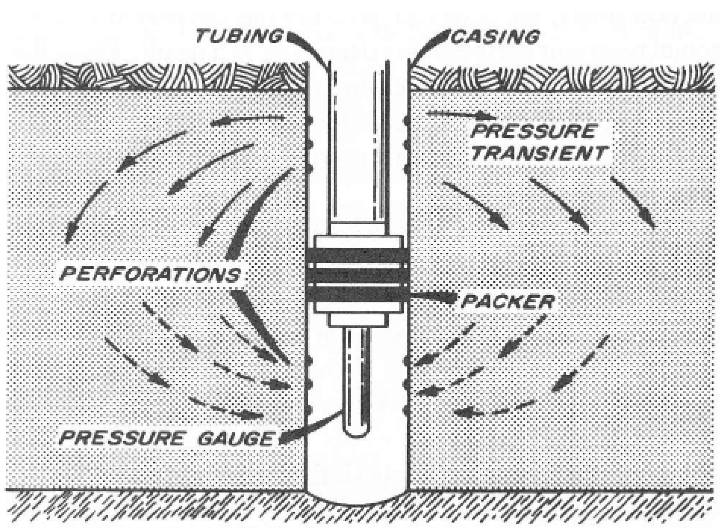


Figure A-23: Vertical Interference or Pulse Test.
From: Earlougher (1977); © SPE, 1977, reproduced with permission; further reproduction prohibited without permission.

Interfacial Tension

Knowledge regarding the IFT between carbon dioxide and brine at in situ conditions is needed for precise measurements of capillary pressure, which in turn impacts relative permeability

(Bachu and Bennion, 2008). IFT is the surface tension at the interface of two immiscible fluids. Surface tension can be measured by a variety of laboratory methods such as the Du Noüy Ring method, the Wilhelmy Plate method, the spinning drop method, the pendant drop method, and other techniques. For additional information, see Bachu and Bennion (2008), del Rio and Neumann (1997), and Nobakht et al. (2007).

IFT can also be estimated mathematically by an empirical power function of pressure, whereby the values of the coefficient and exponent depend on temperature and water salinity (Bachu and Bennion, 2009). Bachu and Bennion (2009) provide parameters for a range of temperature and salinity conditions representative of in situ carbon dioxide-brine systems.

Water Saturation

Water saturation (S_w) describes the fraction of water in a given pore space. It depends on particle size and interparticle porosity (Lucia, 1992). Water saturation is most often determined from resistivity log measurements combined with knowledge of porosity, water resistivity, and shale volume (Alberty, 1992b). Water saturation values range from 0 (completely dry) to 1 (completely saturated). For additional information, see Alberty (1992b). Water saturation can also be determined from cores, for example from capillary pressure testing and other laboratory methods that involve expelling and measuring the formation water or other fluids (Ringen et al., 2001).

Wettability

In a solid, porous medium in contact with two or more fluid phases, wettability is the ability of one of the fluid phases (the wetting phase) to contact the solid preferentially over other phase(s) (Donaldson and Tiab, 2003) (Figure A-24). Wettability has important consequences for the relative permeability and Pe (see below) of pore fluids. These two parameters, in turn, affect the sealing and storage capacities of subsurface units (Chiquet et al., 2007; Li et al., 2005).

Wettability can be observed directly in the laboratory by measuring the contact angle between the solid portions of the formation and formation fluids (Chiquet et al., 2007) or can be inferred using either the Amott method or the USBM (United States Bureau of Mines) test (Donaldson and Tiab, 2003). There are no established techniques for downhole field measurement of wettability.

Salinity, temperature, and pressure can all affect wettability (Donaldson and Tiab, 2003), and wettability measurements will be most applicable if they are taken under conditions that approximate those found within the formation of interest. Additionally, micromodels are currently being developed that will be able to predict changes in wetting phase behavior as reservoir conditions change (PNNL, 2010). These may be useful if the reproduction of reservoir conditions is not possible in the laboratory.

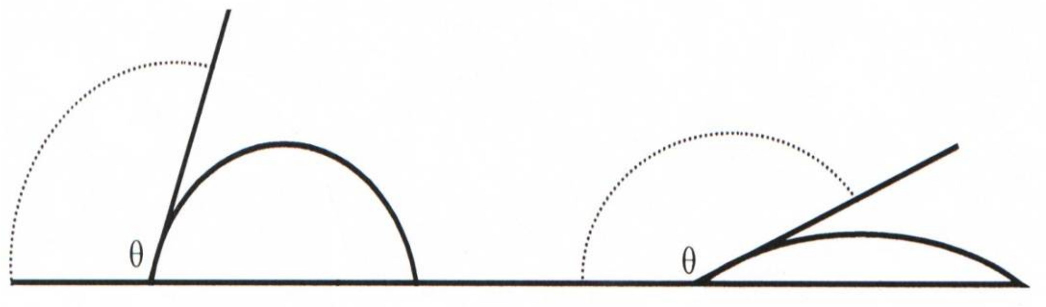


Figure A-24: A Diagram Demonstrating Wetting Angle.
The wetting angle is (180-θ).A fluid with a low wetting angle (at right) and a fluid with a moderate wetting angle (at left) on the same substrate. The fluid with the lower wetting angle would be the wetting phase if both fluids were present in the interconnected pore space of a solid made of the material upon which the wetting angle is being measured.

Capillary Pressure

Capillary pressure is the minimum pressure required for an immiscible non-wetting fluid to overcome capillary and interfacial forces and enter pore space containing the wetting fluid. For carbon dioxide injection into a saline formation, the non-wetting fluid is carbon dioxide and the wetting fluid is the native brine. Capillary pressure has been shown to be affected by IFT and pore-size characteristics, as well as in situ pressure, temperature, and water salinity (Bachu and Bennion, 2008; Wollenweber et al, 2010). Capillary pressure relationships for porous media are typically reported as a function of the wetting phase saturation, and the capillary pressure curves generated by laboratory testing can be used to estimate the irreducible wetting phase saturation of the carbon dioxide/brine/rock system. Mathematical models have also been developed to predict capillary pressure relationships (e.g., Van Genuchten, 1980). Figure A-25 shows capillary pressure curves used in a simulation of carbon dioxide storage in saline formations (Ide et al., 2007).

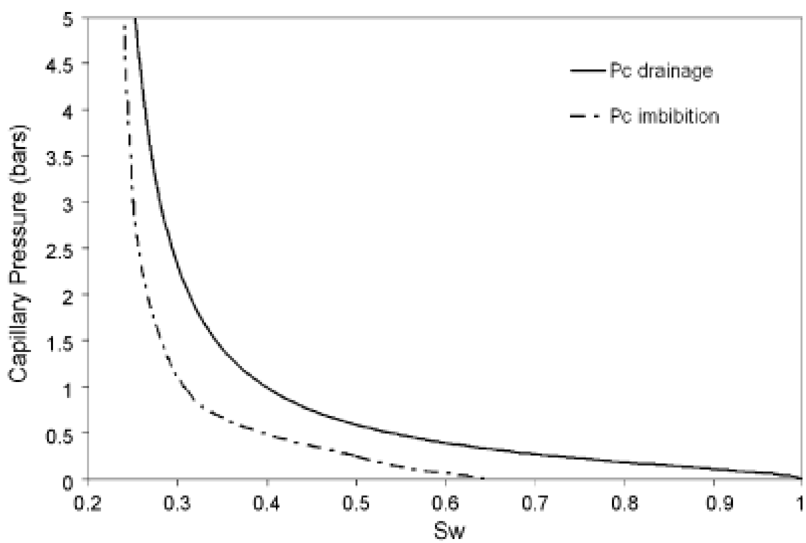


Figure A-25: Capillary Pressure (Drainage and Imbibitions) as a Function of Wetting Phase Saturation.
Generated using the Van Ganuchten Formulation. From: Ide et al. (2007); © Elsevier, reproduced with permission.

Reservoir capillary pressure relationships can be evaluated in the laboratory using the porous plate or centrifuge method (which uses actual or simulated fluids), or the mercury injection method (which simulates the wetting characteristics of the reservoir) (Vavra et al., 1992); descriptions are provided in Section A3.

Several techniques have been developed to measure capillary pressure in situ. Kuchuk et al. (2008) used a permanent downhole electrode array using time lapse resistivity in combination with pressure and flow readings to determine the capillary pressure and other properties of the formation downhole. Vinegar and Waxman (1984) mention the use of polarization logging measurements to determine pore size distribution. The capillary pressure is estimated from the pore size distribution. Others have used nuclear magnetism logging (NML) to estimate capillary pressure. NML has a very short effective range and returns a volume average of the capillary pressure. Freeman (1984) used wireline data consisting of pressure readings with water saturation and porosity data to estimate capillary pressure. Proett et al. (2003) proposed the use of data from a pump-out of drilling mud after drilling to determine capillary pressure. They measured pressure, flow, and fluid properties during the pump-out and used an algorithm to determine the capillary pressure.

Most of the available in situ methods determine the capillary pressure indirectly using data from downhole logs and algorithms based on certain assumptions. The accuracy of the methods likely depends on how closely the formation being tested resembles the assumptions made in developing the algorithm. These methods may not be as accurate as laboratory data, but generally can be done more quickly under in situ conditions.

Viscosity

Viscosity is a property of a fluid that measures resistance to shear stress. In the centimeter gram second (CGS) system, the unit of viscosity is the poise, which is 1 $g \cdot cm^{-1} \cdot s^{-1}$. The ratio of viscosity to density is called the kinematic viscosity, which has the units of stoke or $cm^2 s^{-1}$. Viscosity can be measured in the laboratory with various types of viscometers (e.g., u-tube, falling piston, oscillating, vibrational, rotational, bubble, and other types of viscometers). Close temperature control is essential for accurate measurements. ASTM International maintains standard methods for viscosity measurements (www.astm.org).

In situ, real-time direct measurements of viscosity can be collected at reservoir conditions using a wireline formation tester such as a tool described by O'Keefe et al. (2007). The tool measures the thermophysical properties of the fluid by the vibration of a mechanical resonator submersed in the flowline fluid, and the instrument measures viscosity in the range of 0.25 to 50 cP with a reported accuracy of ±10%.

Density and Specific Gravity

In the field, the in situ density of the formation fluid can be measured during open-hole sampling of reservoir fluids using a wireline formation tester (O'Keefe et al., 2007). The density of subsurface formations can be determined by formation density and combined neutron and density logs (Hancock, 1992; Section A7) and the borehole gravity meter (Herring, 1992).

Carbon dioxide density can be estimated by the Peng-Robison equation of state (Peng and Robinson, 1976) using available software such as the CMG Winprop module (Computer Modeling Group, Ltd., Canada) as described by Nobakht et al. (2007). Carbon dioxide density increases with depth (local pressure gradient) (Figure A-26) and decreases with increasing geothermal gradient (Kovscek, 2002). Brine density can be predicted at in situ temperature, salinity, and pressure conditions by several algorithms as discussed by Adams and Bachu (2002). Other algorithms for predicting density of carbon dioxide-brine mixtures are described by Hassanzadeh et al. (2008).

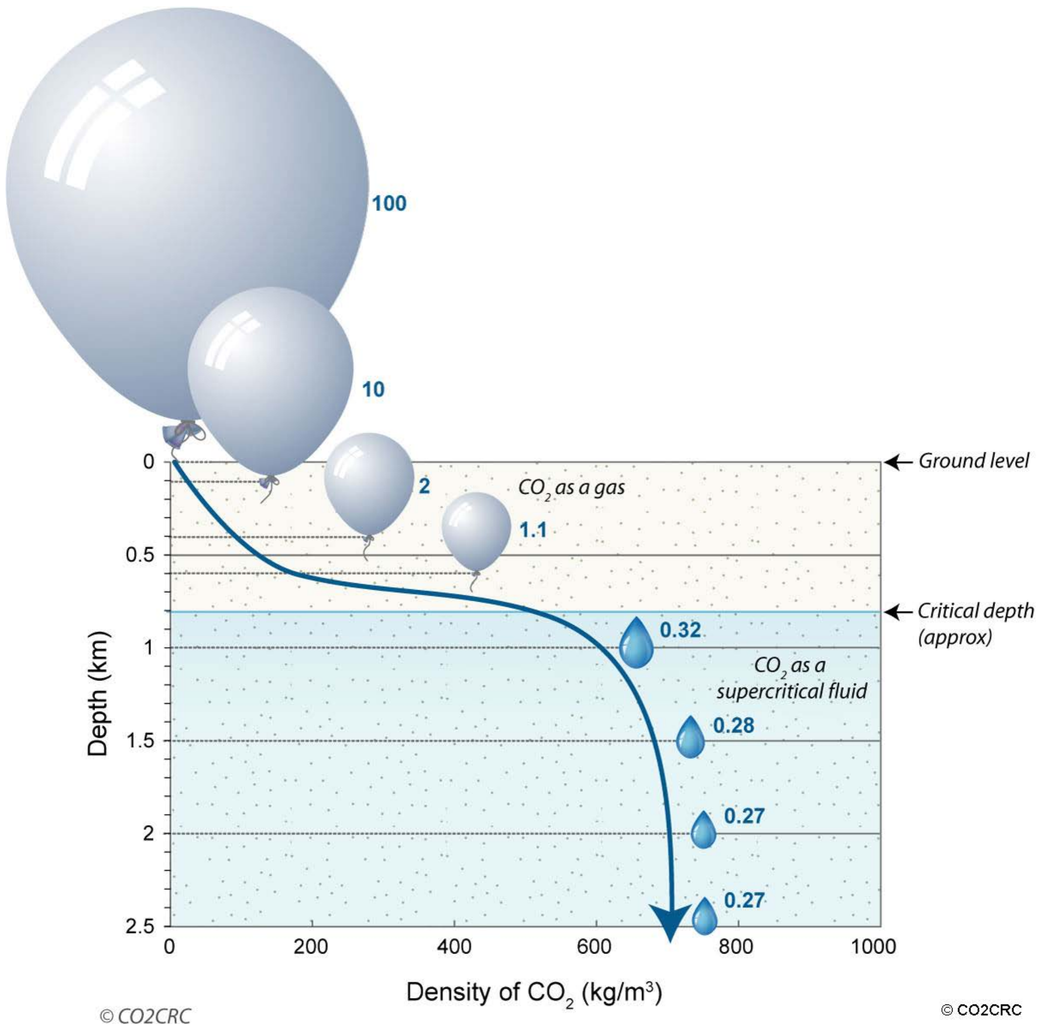


Figure A-26: Density of Carbon Dioxide as a Function of Depth.

Mobility and Mobility Ratio

The mobility of a phase is defined as its relative permeability divided by its viscosity (Warner, 2007; Kopp et al., 2009a; 2009b; Craig, 1980). Mobility combines a rock property, relative permeability (dependent only on the saturation of the two fluid phases and the capillary pressure)

(Bachu and Bennion, 2008), with a fluid property, viscosity. Mathematically, mobility is expressed as:

$$\boldsymbol{\lambda_i} = \frac{\boldsymbol{k_i}}{\boldsymbol{\mu_i}} \qquad \text{Equation 7}$$

where λ_i is the mobility of fluid phase *i*, k_i is the effective permeability of fluid phase *i*, and μ_i is the viscosity of fluid phase *i*. (Relative permeability is discussed in Section 2.3.5 of the guidance and in Section A3 of this Appendix.) Low-viscosity fluids generally have high mobility and high-viscosity fluids generally have low mobility. The mobility ratio (*M)* generally is defined as the mobility of the displacing phase (carbon dioxide for sequestration) divided by the mobility of the displaced phase (e.g., fluid in a saline formation).

M is considered to be either "favorable" or "unfavorable." A favorable mobility ratio is a low value ($M \leq 1$), which means that the displaced fluid (water) has a higher mobility than the displacing phase (carbon dioxide). An unfavorable mobility ratio ($M > 1$) means that the displacing fluid has a higher mobility than the displaced fluid. In practical terms, a favorable mobility ratio means that the displaced water phase can move more quickly through the reservoir rock than the displacing carbon dioxide phase. More importantly, an unfavorable or large *M* value tends to give rise to rapid migration of carbon dioxide along paths of least resistance. Typical values for *M* for reservoir conditions of interest in sequestration are 2–10.

Viscous fingering can cause carbon dioxide to bypass much of the pore space, depending on the heterogeneity and anisotropy of rock permeability, because supercritical carbon dioxide is much less viscous than water and oil. Benson and Cook (2005) noted that only some of the resident oil or water will be displaced during carbon dioxide injection because of the comparatively high mobility of carbon dioxide, thus leading to an average saturation of carbon dioxide in the range of 30–60% during storage in the reservoir.

Capillary and Gravitational Numbers

In addition to mobility, the displacement process will be driven by capillary and buoyancy forces. The capillary number (*Ca*) is defined as the ratio of capillary forces to viscous forces (Kopp et al., 2009a). As carbon dioxide migrates through a formation, some of it is retained in the pore space by capillary forces, known as residual carbon dioxide trapping.

The *Ca* is defined as the ratio of capillary forces to viscous forces and can be used to characterize the extent of carbon dioxide trapping in an injection zone. As carbon dioxide migrates through a formation, some of it is retained in the pore space by capillary forces, known as residual carbon dioxide trapping. Kopp et al. (2009a) examined the effect of *Ca* on storage capacity and concluded that a higher *Ca* is expected to be associated with a lower average carbon dioxide saturation. This expectation is based on the occurrence of stronger capillary forces associated with higher *Ca* values, thus leading to a smoother displacement front during the imbibition process, and resulting in a lower, non-wetting phase (carbon dioxide) saturation in the swept area behind the brine displacement front.

The Gravitational number (*Gr)* is defined as the ratio of the gravitational (buoyancy) forces to the viscous forces (Kopp et al., 2009a; Bryant and Lake, 2005, Chp 18). The type of fluid in the reservoir will influence the magnitude of the buoyancy forces that drive vertical flow of carbon dioxide in an injection zone (Benson and Cook, 2005). For example, the comparatively large density difference between carbon dioxide and formation water creates strong buoyancy forces that drive carbon dioxide upwards. In oil reservoirs, the density difference and buoyancy forces are less, particularly if oil and carbon dioxide are miscible. In gas reservoirs, carbon dioxide migrates downward because carbon dioxide is more dense than natural gas. *Gr* can therefore be used to predict the tendency of flow direction during the injection phase.

Number of Wells

Projects that employ multiple injection wells at a site can accelerate the volume of carbon dioxide injected into storage reservoirs. According to Michael et al. (2010), comparable carbon dioxide injection rates can be achieved in a low-permeability storage reservoir as in a high-permeability reservoir by increasing the number of injection wells. Bachu et al. (2007) and Gibson-Poole et al. (2005) also discussed the benefits of increasing the number of injection wells to improve injectivity in low-permeability rocks. However, if a storage reservoir already has a number of wells that penetrate the reservoir, then there may be a risk of leakage during carbon dioxide injection. For example, Gasda et al. (2004) studied clusters of wells that were previously drilled for hydrocarbon extraction in the Viking Formation, and they concluded that the number of wells that could potentially serve as leakage pathways during injection depends upon whether the injection well is located in an area with a high or low density of pre-existing wells.

Skin Factor

The skin effect or skin factor represents restricted entry into the formation associated with damaged formation near the well bore. In well bores where skin effects are a concern, injectivity can be enhanced by stimulating (e.g., by acid treatment) or by performing a workover (e.g., added perforations) of the injection well (Gidley, 1992; Osborne, 1992).

The concept of skin effect is illustrated in Figure A-27, which shows the pressure distribution from the well bore (bottomhole) flowing pressure, p_{wf}, to the reservoir pressure, p_R for ideal and actual conditions (Golan, 1992). The difference between actual and ideal conditions in the damaged near-well bore region corresponds with the pressure drop associated with the skin effect. For additional information, including estimation of the skin factor, see Golan (1992), Lancaster (1992), Lee (1992), and Lee (2007).

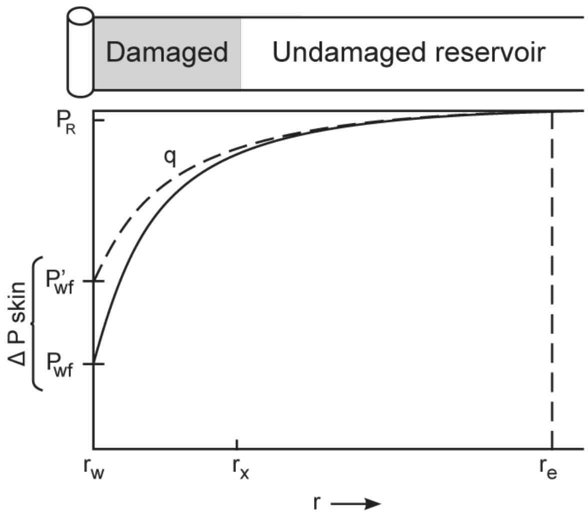


Figure A-27: A Schematic of the Skin Effect.
PR = Reservoir Pressure, Pwf = well bore (bottomhole) flowing pressure, P'wf = ideal well bore flowing pressure, ΔPskin = P'wf – Pwf, rw = well bore radius, ra = radius of skin zone, re = radius of drainage. q represents pressure profile under steady state conditions with no skin effect. From: Golan (1992); © AAPG 1992, by permission of the AAPG whose permission is required for further use.

Diffusion Coefficient and Dispersivity

Molecular diffusion is defined as the net transport of a molecule in a liquid or gas medium as a result of intermolecular collisions and driven by a gradient through the medium such as temperature, pressure, or concentration (Tucker and Nelken, 1990). The diffusion coefficient or diffusivity is defined as the ratio of the net mass flux per unit gradient, and the rate of diffusion is a function of the properties of the compound as well as the medium through which the compound moves (Tucker and Nelken, 1990). Dispersion is controlled by the intensity of turbulent mixing rather than molecular diffusion. Methods for estimating values of diffusion coefficient and dispersivity are summarized by Tucker and Nelken (1990).

Sweep Efficiency

Volumetric sweep efficiency E_V is a term commonly used in the petroleum industry to represent the ratio of the volume of fluid contacted by a displacing agent to the volume of fluid originally in place. Values of E_V range from 0 to 1 (or 0 to 100%) and are typically in the range of 40% to 60% for water flooding processes for hydrocarbon extraction from reservoirs (Lake, 1989). Volumetric sweep efficiency can be further defined as the product of areal sweep efficiency E_A and vertical sweep efficiency E_I whereby (Lake, 1989; Craig, 1980; Warner, 2007):

$$\boldsymbol{E_V = E_A E_I} \qquad \text{Equation 8}$$

Areal sweep efficiency E_A is generally used in the petroleum industry to represent the ratio of the area contacted by the displacing agent to the total area, and vertical sweep efficiency E_I is used to characterize the ratio of the cross-sectional area contacted by the displacing agent to the total cross-sectional area (Lake, 1989; Craig, 1980; Warner 2007). Several correlations have been developed and reported in the petroleum literature for estimating sweep efficiency through porous media for various well field injection patterns and simplifying assumptions (Craig, 1980).

Methods for Storage Capacity Estimation

Methods for estimating carbon dioxide storage capacity can be divided into static and dynamic models (USDOE, 2008a). Static models are typically used for estimating carbon dioxide storage capacity prior to injection, although static models can also be used for estimating storage after injection commences. Dynamic models are typically employed after injection commences. The application of static and dynamic models for estimating carbon dioxide storage capacity is based on methods routinely used for estimating petroleum reserves, ground water resources, underground natural gas storage, and in the UIC Program. Parameters typically used to calculate storage capacity are listed in Table A-3. Additional discussion regarding static and dynamic modeling methods for estimating carbon dioxide storage is provided below.

Static Models

Static models are typically used for estimating carbon dioxide storage capacity prior to the startup of injection. Static models, which include volumetric and compressibility methods, rely on parameters that are directly related to the geologic description of the area for injection such as porosity, area, thickness and compressibility (USDOE, 2008a and 2008b). Standardized methodologies for estimating carbon dioxide storage capacity in geological media (coal beds, oil and gas reservoirs, and deep saline formations) using static models have been adopted the Carbon Sequestration Leadership Forum (http://www.cslforum.org). These methodologies, as described by Bachu et al. (2007), are summarized below.

Coal Beds

The carbon dioxide storage capacity of a suitable coal bed can be estimated based on analogy with estimating the total gas in place (capacity) and reservoir deliverability (White et al., 2005). For a coal bed with gas already adsorbed by the coal, the initial gas in place (IGIP) can be calculated by the relation (Bachu et al., 2007; White et al., 2005):

$$\mathbf{IGIP} = \boldsymbol{A} \times \boldsymbol{h} \times \boldsymbol{n_C} \times \boldsymbol{G_C} \times (\mathbf{1} - \boldsymbol{f_a} - \boldsymbol{f_m}) \qquad \text{Equation 9}$$

where A is the area and h is the effective thickness of the coal zone, n_C is the bulk coal density (generally assumed to be 1.4 t/m^3), G_C is the coal gas content, and f_a and f_m are the ash and moisture weight content fractions of the coal, respectively. The coal gas adsorption capacity can be assumed to follow a pressure-dependent Langmuir isotherm in the form:

$$\boldsymbol{G_{CS}} = \boldsymbol{V_L} \frac{\boldsymbol{P}}{\boldsymbol{P} + \boldsymbol{P_L}} \qquad \text{Equation 10}$$

where G_{CS} is the gas content at saturation, P is the pressure, and V_L and P_L are Langmuir volume and pressure, respectively. These relations are based on the assumptions that coal has a high affinity for carbon dioxide, 100% saturation is achieved, and all of the coal is accessed by the injected carbon dioxide. To estimate the *effective* carbon dioxide storage capacity in coal beds, the analogy is drawn to the estimation of the producible gas in place (PGIP) from the IGIP with the relation:

$$\mathbf{PGIP} = \boldsymbol{R_f} \times \boldsymbol{C} \times \mathbf{IGIP} \qquad \text{Equation 11}$$

where R_f is the recovery factor and C is the completion factor (or effective contact area). The completion factor is an estimate of the coal thickness that will contribute to gas production or storage. It should be noted that there are limited field data for quantification of the recovery factor (Bachu et al., 2007).

Oil and Gas Reservoirs

Calculation of carbon dioxide storage capacity for depleted oil and gas reservoirs is based on the assumption that the same storage volume is available for injected carbon dioxide as was previously occupied by the extracted hydrocarbons (Bachu et al., 2007). This condition may be altered, for example, in the case of formation water invading a pressure-depleted reservoir. Another assumption is that carbon dioxide injection will continue until the pressure is restored to its original reservoir condition. As discussed previously, the re-pressurization of a depleted reservoir may be problematic with regard to the integrity of the reservoir and/or cap rock; thus, the maximum sustainable pore pressure may need to be lower than the original reservoir pressure.

An equation for calculating the carbon dioxide storage capacity in oil and gas reservoirs is based on the geometry of the reservoir (Bachu et al., 2007):

$$\boldsymbol{M_{CO_2t}} = \boldsymbol{\rho_{CO_2r}}\left[\boldsymbol{R_f A h}\emptyset(\mathbf{1} - \boldsymbol{S_w}) - \boldsymbol{V_{iw}} + \boldsymbol{V_{pw}}\right] \qquad \text{Equation 12}$$

where:

M_{CO2t} = theoretical mass storage capacity for carbon dioxide in a reservoir at in situ conditions [M]
ρ_{CO2r} = carbon dioxide density at reservoir conditions [ML^{-3}]
R_f = recovery factor [dimensionless]
A = reservoir area [L^2]
h = thickness [L]
ø = porosity [dimensionless]
S_w = water saturation [dimensionless]
V_{iw} = volume of injected water [L^3]
V_{pw} = volume of produced water [L^3]

Bachu et al. (2007) provide alternative relations that account for fluid compressibility in gas reservoirs:

$$\boldsymbol{M_{CO_2t}} = \boldsymbol{\rho_{CO_2r} R_f}(\mathbf{1} - \boldsymbol{F_{IG}}) \times \mathbf{OGIP} \times \left[\frac{(\boldsymbol{P_s Z_r T_r})}{\boldsymbol{P_r Z_s T_s}}\right] \qquad \text{Equation 13}$$

and for fluid compressibility in oil reservoirs:

$$\boldsymbol{M_{CO_2t}} = \boldsymbol{\rho_{CO_2r}} \times \left[\frac{\boldsymbol{R_f}\textbf{OOIP}}{\boldsymbol{B_f}} - \boldsymbol{V_{iw}} + \boldsymbol{V_{pw}}\right] \qquad \text{Equation 14}$$

where OGIP and OOIP represent the original gas and oil in place at surface conditions, F_{IG} is the fraction of injected gas, B_f is the formation volume factor that converts oil volume from standard conditions to in situ conditions, V_{iw} and V_{pw} are the volumes of injected and produced gas, P, T, and Z are pressure, temperature, and gas compressibility, respectively, and the subscripts r and s represent reservoir and surface conditions.

The effective storage capacity can be influenced by the historical operation of the oil and gas reservoir (i.e., pressure depletion and formation water influx), thus reducing the total available capacity for carbon dioxide storage. The effective carbon dioxide storage capacity can also be influenced by carbon dioxide mobility, fluid density differences, reservoir heterogeneity, and residual water saturation. These influences can be combined to represent an efficiency factor for estimating an effective storage capacity (Bachu et al., 2007; Doughty and Pruess, 2004):

$$\boldsymbol{M_{CO_2e} = C_m C_b C_h C_w C_a M_{CO_2t} \equiv C_e M_{CO_2t}} \qquad \text{Equation 15}$$

where M_{CO2e} is the effective reservoir carbon dioxide storage capacity, M_{CO2t} is the theoretical mass storage capacity of carbon dioxide in a reservoir at in situ conditions, and the coefficient C_e is a single effective capacity coefficient that incorporates the cumulative effects of the other coefficients represented by subscripts *m* for mobility, *b* for buoyancy, *h* for heterogeneity, *w* for water saturation, and *a* for formation strength. Currently, limited data are available for estimating values for C_e.

Deep Saline Formations

For deep saline formations, carbon dioxide storage capacity estimates can be developed for structural and stratigraphic traps, residual gas traps, solubility traps, mineral traps, and hydrodynamic traps (Bachu et al., 2007) as described below.

For *structural and stratigraphic traps*, the formation is initially saturated with water (instead of hydrocarbons), and the theoretical volume available for carbon dioxide storage, V_{CO2t}, can be calculated by the relation (Bachu et al., 2007):

$$\boldsymbol{V_{CO2t} = Ah\emptyset(1 - S_{wirr})} \qquad \text{Equation 16}$$

where A is the reservoir area, h is thickness, ϕ is porosity, and S_{wirr} is the irreducible water saturation. Similar to oil and gas reservoirs, the effective carbon dioxide storage volume, V_{CO2e}, can be estimated by:

$$\boldsymbol{V_{CO2e} = C_c V_{CO2t}} \qquad \text{Equation 17}$$

where C_c is a capacity coefficient that represents the effects of heterogeneity, buoyancy, and sweep efficiency, and it can be determined through numerical simulation and/or field study.

Okwen et al. (2010) developed a method for estimating carbon dioxide storage efficiency applicable to structural and stratigraphic trapping that can be characterized by carbon dioxide mobility, buoyancy forces, and residual saturation. The mass of carbon dioxide that corresponds to the effective storage volume can be estimated by multiplying V_{CO2e} by carbon dioxide density at storage temperature and pressure conditions.

Residual gas traps form within a saline formation when injected carbon dioxide migrates through the porous media and water moves back into the pore space. For example, during injection, carbon dioxide can migrate laterally and upward due to buoyancy forces. Once injection stops, carbon dioxide can continue to migrate, water enters the pore space, and residual, immobile carbon dioxide is left behind the plume (Juanes et al., 2006). Qi et al. (2009) proposed an injection strategy whereby carbon dioxide and brine are injected together and thus maximize storage efficiency in formations. The theoretical carbon dioxide storage volume of the residual gas traps can then be estimated by the relation (Bachu et al., 2007):

$$\boldsymbol{V_{CO2t}} = \Delta \boldsymbol{V_{trap}} \emptyset \boldsymbol{S_{CO2t}} \qquad \text{Equation 18}$$

where ΔV_{trap} represents the carbon dioxide-invaded rock volume and S_{CO2t} is the trapped carbon dioxide saturation. ΔV_{trap} and S_{CO2t} can be estimated through numerical simulations (e.g., Juanes et al., 2006). The mass of stored carbon dioxide can be estimated by multiplying the storage volume by carbon dioxide density at in situ conditions.

Solubility trapping of carbon dioxide is a relatively slow process and is assumed to become significant after cessation of injection (Bachu et al., 2007). Although dissolution of free-phase carbon dioxide occurs rapidly, and water in direct contact with injected carbon rapidly becomes saturated with carbon dioxide, the available contact area between free-phase carbon dioxide and unsaturated water is small, greatly limiting solubility trapping. When migration of carbon dioxide has stopped (thus reducing the influence of dispersion), then diffusion, which is very small, becomes the only mechanism enabling unsaturated water to contact carbon dioxide unless the water itself is moving. If a hydraulic gradient within the formation replaces the carbon dioxide-saturated water with unsaturated water, or the rock permeability and thickness are conducive to the development of convection within the pore system, then carbon dioxide will continue to dissolve into the unsaturated water that passes the contact area. The theoretical mass carbon dioxide storage capacity can be estimated using a simplified relation and average values for formation thickness, porosity, and carbon dioxide content in formation fluid as (Bachu et al., 2007):

$$\boldsymbol{M_{CO2t}} = \boldsymbol{Ah}\emptyset\left(\boldsymbol{\rho_S X_S^{CO2}} - \boldsymbol{\rho_0 X_0^{CO2}}\right) \qquad \text{Equation 19}$$

where ρ is the density of the formation water, X^{CO2} is the mass fraction carbon dioxide content in formation water, and the subscripts *0* and *S* represent initial and saturated carbon dioxide content, respectively. Similar to the relations for coal beds and oil and gas reservoirs, the mass carbon dioxide storage capacity can be estimated by multiplying the theoretical value by a coefficient that includes the effects of spreading and dissolution of carbon dioxide in the whole formation. However, for a site-specific application, the theoretical carbon dioxide storage capacity associated with solubility trapping should be assessed by numerical modeling (Bachu et al., 2007).

Mineral trapping of carbon dioxide depends on the chemical composition of the rock matrix and formation waters, in situ temperature and pressure conditions, the interface between the mineral grains and the formation water containing dissolved carbon dioxide, and the flow of fluids past the interface (Bachu et al., 2007). For site-specific applications, the amount and time frame of carbon dioxide storage associated with mineral trapping should be estimated by numerical modeling and supported, where possible, with laboratory testing and field data.

Hydrodynamic trapping of carbon dioxide is a combination of mechanisms (structural and stratigraphic trapping, dissolution, mineral precipitation, residual gas trapping) operating simultaneously, but at different rates, while an injected plume of carbon dioxide expands and migrates in a storage reservoir (Bachu et al., 2007). Carbon dioxide storage capacity associated with hydrodynamic trapping therefore needs to be evaluated at a specific point in time as the sum of the component mechanisms by numerical simulations.

Dynamic Models

Dynamic models are generally considered applicable for estimating carbon dioxide storage capacity after initiation of carbon dioxide injection (USDOE, 2008a). They would therefore be useful after receiving a permit to operate a Class VI injection well, as a way to monitor storage capacity over time. Dynamic models include decline curve analysis, material balance, and reservoir simulation.

Decline Curve Analysis

The decline curve analysis is a dynamic method for estimating subsurface storage volumes based on a simple exponential relation of injection rate and time (USDOE, 2008a):

$$\boldsymbol{q_{CO2} = q_{CO2i}e^{-Dt}} \qquad \text{Equation 20}$$

where q_{CO2} is the carbon dioxide injection rate and the subscript i denotes the initial injection rate, D is a decline coefficient that represents flow characteristics of the formation, and t represents time. Carbon dioxide storage capacity, G_{CO2}, can be estimated by the relation:

$$\boldsymbol{G_{CO2} = \frac{(q_{CO2i} - q_{CO2})}{D}} \qquad \text{Equation 21}$$

where the decline coefficient D is determined from the exponential decline equation for a given injection rate history. This decline curve analysis is generally considered applicable to individual wells or entire fields, provided the exponential trend exists. Additional information regarding theory and application of decline curve analysis techniques is provided in Arps (1962), Campbell and Campbell (1978), and Li and Horne (2003). This relation can be used to estimate carbon dioxide storage capacity likely to be attained with continued injection.

Material Balance

The material balance method for estimating carbon dioxide storage capacity is based on the relationship between cumulative carbon dioxide injection and the corresponding pore pressure as a function of time (USDOE, 2008a). The relation is analogous to the p/z plots used in gas reservoirs and underground gas storage reservoirs (e.g., Harrell and Cronquist, 2007), where z is the gas compressibility factor of carbon dioxide evaluated at pressure p. A straight line is expected on a plot of p/z versus cumulative carbon dioxide gas injection. The carbon dioxide storage capacity can be estimated from this plot by extrapolating the curve and determining the value of cumulative carbon dioxide gas injection that corresponds to the maximum p/z value at capacity pressure.

Reservoir Simulation

Reservoir simulation is considered the most advanced method for estimating carbon dioxide storage capacity, provided the input data adequately represent the injection formation and operating conditions (USDOE, 2008a). The purpose of simulation is to estimate field performance under one or more operational schemes (Batycky et al., 2007). For example, the simulation can be used to study actual field or pilot performance and thus improve estimates for carbon dioxide storage capacity. As discussed previously, reservoir simulation can be also used to develop estimates of specific carbon dioxide storage trapping mechanisms (e.g., hydrodynamic trapping). Reservoir simulation is the most resource-intensive method of estimating carbon dioxide storage. However, it requires the input of data at a scale and resolution appropriate for obtaining results at formation scale. Additional discussion regarding reservoir simulation is provided in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*.

A8. Information to Support Pre-Injection Logging and Testing

To support submittal of the well logs required at 40 CFR 146.87, this section describes various types of logs that can be used during formation testing. This information supplements Section 4.1 of the guidance.

Gamma ray logs measure the natural radioactivity emitted by radioactive isotopes (e.g., potassium, thorium, and uranium) in minerals. Gamma ray logs are the most common log run for stratigraphic correlation because they are relatively unambiguous and easy to interpret by a qualified analyst (Evenick, 2008) (Figure A-28). The intensity of radioactivity is measured by a scintillation counter in American Petroleum Institute (API) units (Evenick, 2008). Because clays tend to have higher concentrations of potassium and thorium than other minerals, gamma ray logs can provide information on the clay and mica content (or "shaliness") of the formation (Johnson and Pile, 2006). The log curve can also be compared to a section with 100% or 0% shale saturation to determine a "shale baseline" and calculate the percent of shale present in other regions of the log (Johnson and Pile, 2006).

The spectral gamma ray tool, an advanced version of the gamma ray tool, allows for the identification of gamma ray counts caused by specific elements. This allows for the removal of gamma ray counts caused by uranium, which is often deposited by formation fluids, although it is also found in some sandstones and carbonates (Johnson and Pile, 2006). Gamma ray logs are virtually unaffected by changes in porosity (Johnson and Pile, 2006).

Spontaneous potential (SP) logs show naturally occurring differences in electric potential (usually measured in millivolts, mV) due to salinity differences between the drilling mud and formation fluids, and between formation fluids in different units (Johnson and Pile, 2006). The SP response can be used to correlate formations between wells, determine permeability, and estimate formation fluid resistivity (Evenick, 2008; Alberty, 1992b; Hancock, 1992). Because SP logs reflect differences in electric potential, contrasts in permeability and salinity between formations are critical (see Figure A-28). Although not good for identifying general lithology, SP logs can help in differentiating shales from carbonates or sandstones, and they work best when shale layers separate more permeable formations (Evenick, 2008; Johnson and Pile, 2006). Hancock (1992) describes other conditions where SP logs are not applicable or difficult to interpret.

The SP response typically varies by lithology and can be used to correlate formations between wells, determine permeability, and estimate formation fluid resistivity (Alberty, 1992b; Hancock, 1992). Because SP logs reflect differences in electric potential, contrasts in permeability and salinity between formations are critical (see Figure A-28). SP logs are influenced by the presence of impermeable limestones and work best when shale layers separate more permeable formations (Johnson and Pile, 2006). Hancock (1992) describes other conditions where SP logs are not applicable or difficult to interpret.

SP logs can be challenging to correlate because they are not good indicators of lithologic boundaries (Evenick, 2008). With the advent of other more specialized and better resolved techniques, the role of SP logs has been gradually diminished (Blackbourn, 1990).

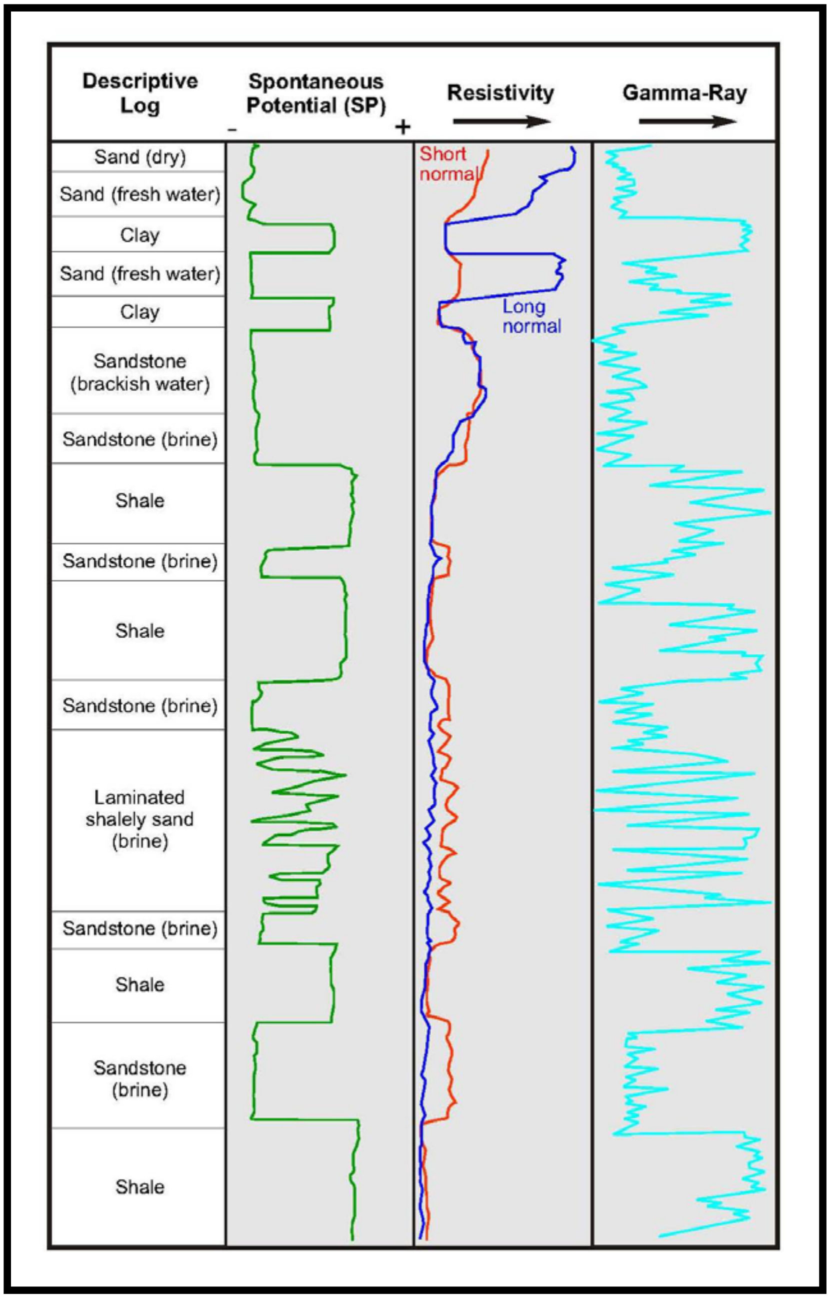


Figure A-28: Example of Geophysical Well Logs.

Caliper logs show the measured diameter of the borehole. A caliper log can be used as a crude lithologic indicator by comparing the caliper reading to the size of the drill bit, as shown in Table A-4. Different rock and sediment types show different responses on the caliper log, depending on properties such as permeability and level of consolidation. Hancock (1992) describes the various responses that indicate specific lithologies. In general, shales, coals, and bentonites tend to wash out with drilling (Evenick, 2008).

Table A-4: Interpreting Borehole Condition from Caliper Readings.

	Well Bore Larger than Expected	Well Bore as Expected	Well Bore Smaller than Expected
Indicated by	Caliper > Bit size	Caliper = Bit size	Caliper < Bit size
Possible Rock Characteristics	Soft or Fractured	Hard / Unfractured	Permeable
Possible Cause	Wash Out		Mud-cake Accumulation

Porosity Logs

Porosity logs are a class of geophysical logs that indirectly measure formation porosity, and include density, neutron, sonic, and magnetic resonance logs, which are individually described below. Typically, multiple logs are run simultaneously, and the results from the multiple logs can be interpreted to estimate porosity and formation lithology (AAPG, 2004). All of these logs would not necessarily need to be run to comply with the Class VI Rule porosity logging requirements. Rather, a suite of porosity logs may be run based on site conditions, owner or operator preferences, and as approved by the UIC Program Director.

- ***Sonic logs*** record the sound wave transit time between a source and receiver(s) through the rock formation. The transit time depends on the lithology and porosity of the formation, so it is necessary to determine or estimate lithology to measure porosity from a sonic log. Lithology may be known through core analysis, interpretation of other logs, or interpretation of sonic logs simultaneously with other porosity logs. For shale-free lithologies, the transit time is frequently related to porosity and mineral fractions. Estimates of porosity provided by sonic logs are categorized as primary porosities which excludes vugs and fractures that can be important in many carbonate sequences. Additionally, the presence of hydrocarbons in a formation will increase the interval transit time, and this effect is corrected for prior to estimating porosity (AAPG, 2004); owners or operators of GS projects in depleted reservoirs should bear this in mind when selecting porosity logs;
- ***Density logs*** measure the bulk density of the formation, including the densities of the rock and the pore fluid. The logs reflect changes in the rock composition, the porosity, and the contained fluids. The logging device consists of a gamma ray source and two detectors; this arrangement allows the results to be compensated for variable rugosity (roughness) and mud-cake thickness (Johnson and Pile, 2006). Porosity determination requires an average value for matrix density which may vary both between and within formations. Bulk densities from logs and laboratory-measured core porosities can be used to establish correlations between density and porosity for a particular interval. An example with density log included as a component of a porosity log is presented in Figure A-29;
- ***Neutron logs*** measure the hydrogen concentration in both pore fluids and in chemically bound water. In shale-free formations, hydrogen atoms are present primarily in the water phase, and neutron logs therefore measure aqueous fluid-filled porosity. Low measurement results from the neutron logger correspond to larger porosity values.

Similar to density logs and sonic logs, neutron log responses are dependent on formation lithology. Additionally, the presence of gas within the pores affects the neutron log response and also needs to be considered in selecting appropriate logs. The neutron log measure of porosity is overestimated in shales because hydrogen atoms are present within the clay structure in addition to pore water. An example neutron porosity log included as a component of a porosity log is presented in Figure A-29; and

- ***Nuclear magnetic resonance*** (NMR) logs measure the free precession of proton nuclear magnetic moments in the earth's magnetic field. Hydrogen protons in solids or bound to surfaces show differences in responses compared to bulk fluids in pore space. Therefore, these logs can be used to determine residual water saturation, the effective porosity, permeability, pore size distribution, and residual oil saturation. Compared to the other porosity logging techniques discussed below, NMR logging porosity estimates are insensitive to formation lithology type, and therefore the NMR log may be run alone as a porosity log.

As noted above, the response of sonic logs, density logs, and neutron logs depend not only on the porosity of the formation, but also the lithology. Common lithologies that may be encountered include sandstone, limestone, dolomite, anhydrite, and salt. Accurately calculating porosity from the measurement response requires that the lithology at each depth be known or estimated based on core analyses or other available information (see Sections 2.3.4 and 4.2). However, both lithology and porosity can be inferred if at least two of the above-mentioned logs are run and interpreted concurrently. This is possible using established relationships for the response from several logging tools. See AAPG (2004) for detailed information regarding porosity log measurement combinations and interpretation.

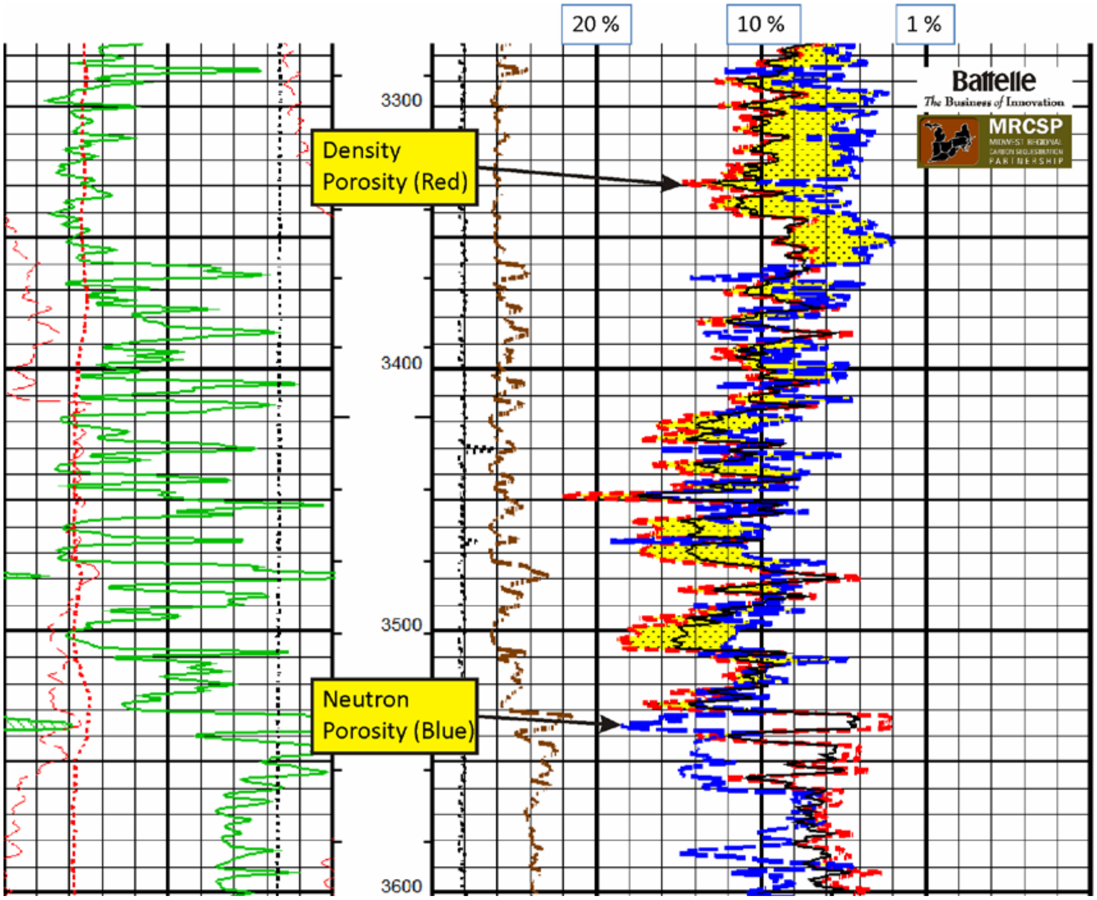


Figure A-29: Example Porosity Log, Including Density (Red) and Neutron (Blue) Logs, for the Cincinnati Arch Validation Test Well.
From: Battelle Memorial Institute.

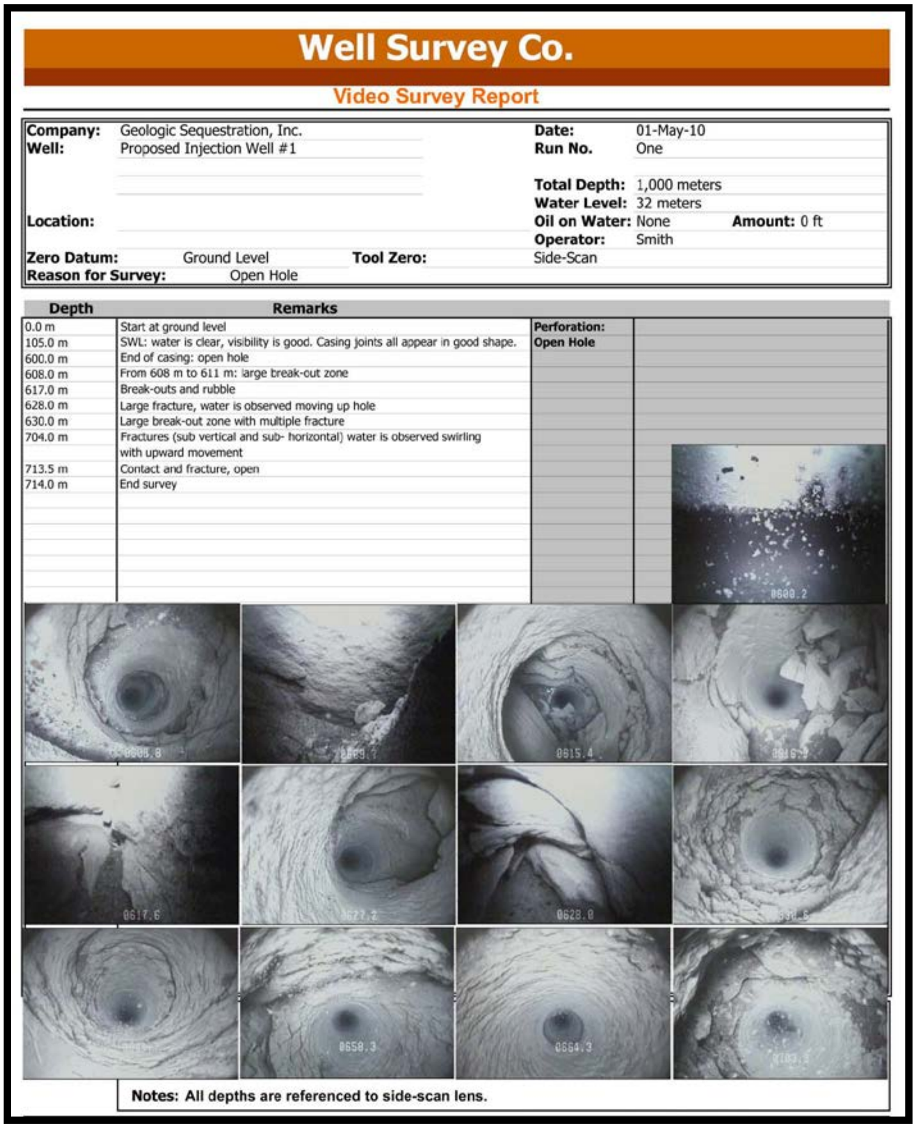
Fracture Finder Logs

Several types of logs may be used for fracture detection, including sonic logs and a number of borehole imaging logs (Telford et al., 1990; AAPG, 1994). Not all logs discussed below must be run to comply with the Class VI Rule fracture finder logging requirements. Rather, a single type of fracture finder log may be run based on site conditions and operator preferences, and as approved by the UIC Program Director.

- ***Sonic logs,*** described above, can also be used for fracture detection. The logging tool provides a sonic signal, and the resulting log is a vertical graph of the amplitude and travel time of the reflected signal. A decrease in amplitude where sonic travel time is constant may indicate open fractures (Telford et al., 1990). As described above, sonic logs measure primary porosity, which excludes fractures. However, used with either neutron or density logs, both of which provide an estimate of the total porosity, sonic logs would yield an estimate of the proportion of vugs and fractures as secondary porosity;
- ***Borehole televiewers,*** also termed acoustic borehole images, make use of reflected sonic waves. The recorded sonic amplitude and travel time are assigned colors to create an image. The resulting logs are color-relief images of the borehole wall, based on acoustic

travel time and amplitude. Low-amplitude, high travel-time features, including fractures, are typically assigned dark colors. As with sonic fracture finder logs, shales and other features that result in a low sonic amplitude are considered during log interpretation;

- ***Electrical borehole imaging logs*** operate under a similar principle as acoustic imaging logs. Because this is an electrical log, the test is conducted in boreholes filled with a conductive drilling fluid. Measured resistivity values are assigned colors to develop an image. The resulting log is a color-relief image of the resistivity of the borehole wall. Low-resistivity features, including shales and fluid-filled fractures, are typically displayed as dark colors; and
- ***Borehole video imaging logs*** have become more common in recent years and may be used to detect fractures. A video log is conducted by lowering a video camera into the well. The video is seen in real time and recorded at the surface, allowing for detailed focus on features of interest. Video logs can be conducted in liquid-filled or open boreholes, as long as the borehole fluids are relatively clear. Fractures are evident on borehole video logs (Figure A-30).



Well Survey Co.

Video Survey Report

Company: Geologic Sequestration, Inc.
Well: Proposed Injection Well #1
Location:
Date: 01-May-10
Run No. One
Total Depth: 1,000 meters
Water Level: 32 meters
Oil on Water: None **Amount:** 0 ft
Operator: Smith
Zero Datum: Ground Level **Tool Zero:** Side-Scan
Reason for Survey: Open Hole

Depth	Remarks
0.0 m	Start at ground level
105.0 m	SWL: water is clear, visibility is good. Casing joints all appear in good shape.
600.0 m	End of casing: open hole
608.0 m	From 608 m to 611 m: large break-out zone
617.0 m	Break-outs and rubble
628.0 m	Large fracture, water is observed moving up hole
630.0 m	Large break-out zone with multiple fracture
704.0 m	Fractures (sub vertical and sub- horizontal) water is observed swirling with upward movement
713.5 m	Contact and fracture, open
714.0 m	End survey

Perforation:
Open Hole

Notes: All depths are referenced to side-scan lens.

Figure A-30: Example of Borehole Video Imaging Log Showing Formation Fractures.

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