United States Environmental Protection Agency

Geologic Sequestration of Carbon Dioxide

Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells

Office of Water (4606M) EPA 816-P-13-004 December 2013

Disclaimer

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

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

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

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

Note that this document only addresses issues covered by EPA’s authorities under the SDWA. Other EPA authorities, such as Clean Air Act (CAA) 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

The *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells* are now codified in the U.S. Code of Federal Regulations [40 CFR 146.81 *et seq*.]. These requirements are often collectively 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 that are protective of underground sources of drinking water (USDWs). EPA developed the Class VI Rule to ensure that USDWs are sufficiently protected during all phases of geologic sequestration (GS) operations. The Class VI requirements are built upon the existing UIC regulatory framework and tailored to the unique nature of GS. This guidance is part of a series of technical guidance documents that EPA is developing to support owners or operators of Class VI wells and the UIC Program permitting authorities in the implementation of the Class VI Rule. The Class VI Rule and related documents are available at
http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm.

Carbon dioxide is currently injected into some oil and gas reservoirs for the purpose of enhancing the recovery of oil and gas. Injection wells used for enhanced oil recovery (EOR) and enhanced gas recovery (EGR)—collectively referred to as enhanced recovery or ER wells—are regulated as Class II wells under the UIC Program. EPA anticipates, however, that carbon dioxide injection for the purpose of GS may also occur in depleting or depleted oil and gas reservoirs. The Agency believes that if the business model for a well or group of wells changes from an ER-focused activity to one that maximizes carbon dioxide injection volumes and permanent storage, then the risk of endangerment to USDWs is likely to increase and such wells may need to be re-permitted as Class VI wells [75 FR 77230, 77244, December 10, 2010].

This *Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells* provides information regarding the transition of a Class II well to a Class VI well. This information includes the factors specified in the Class VI Rule at 40 CFR 144.19 that inform when re-permitting must occur. This guidance also provides information regarding Class VI regulations that may be of interest to owners or operators of Class II wells and Class II UIC Program Directors.

Owners or operators of Class II wells that are injecting carbon dioxide for the primary purpose of long-term storage into an oil or gas reservoir must apply for and obtain a Class VI permit where there is an increased risk to USDWs compared to traditional Class II operations using carbon dioxide [40 CFR 144.19(a)]. EPA recognizes that there may be some carbon dioxide trapped in the subsurface at ER operations; however, if the Class VI UIC Program Director has determined that there is no increased risk to USDWs, then these operations would continue to be permitted under the Class II requirements. EPA has identified factors for owners or operators and Class VI UIC Program Directors to consider when determining if risks to USDWs have increased [40 CFR 144.19(b)]. No single factor should be relied on to make a determination of injection purpose and potential risk. Rather, all available factors should be considered in determining the appropriate well class for a carbon dioxide injection well in an oil or gas reservoir.

Once a determination has been made that a Class VI permit is needed to continue injection, a number of requirements must be fulfilled, both at the time of re-permitting and during future operations. The owner or operator must demonstrate that the proposed injection well is appropriately constructed and operable as a Class VI well and will not endanger USDWs [40 CFR 146.81(c)]. The Class VI Rule describes the requirements that must be met in order to grandfather existing Class II wells to Class VI wells, including a demonstration that the wells meet the requirements at 40 CFR 146.86(a). This guidance document describes a number of requirements an owner or operator must follow including well construction and operation, GS site testing and monitoring, post-injection site care (PISC) and emergency and remedial response, among other requirements. In addition, a Class VI well owner or operator must adhere to more comprehensive operating requirements than those required for Class II wells, as specified at 40 CFR 146.88. Mechanical integrity testing requirements for Class VI wells at 40 CFR 146.89 are more rigorous than those for Class II wells. Some testing and monitoring procedures are unique to Class VI wells, such as plume and pressure front tracking [40 CFR 146.90(g)]. PISC [40 CFR 146.93] and emergency and remedial response [40 CFR 146.94] requirements are also unique to Class VI wells. These combined requirements provide protection for USDWs and are tailored to the longer timeframes and greater injection volumes expected at GS operations.

Under the Class VI Rule, new aquifer exemptions will not be granted for Class VI wells. However, some Class II wells currently operate with aquifer exemptions; as a result, when these Class II wells are re-permitted for GS, the Class VI Rule allows owners or operators to request an expansion of the areal extent of a previously existing aquifer exemption [40 CFR 144.7(d)]. To do this, the owner or operator must define the new expanded area for the aquifer exemption, per 40 CFR 144.7, and show that the new area meets the criteria for exempted aquifers given at 40 CFR 146.4. These criteria serve to ensure that the exempted area is not used as a drinking water source and is not likely to be used as a drinking water source in the future. This guidance document outlines the process by which this expansion may be requested, evaluated, approved or disapproved.

Table of Contents

List of Figures

Table

Acronyms and Abbreviations

AoR	Area of Review
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BOPD	Barrels of Oil per Day
CFR	Code of Federal Regulations
DOE	United States Department of Energy
EGR	Enhanced Gas Recovery
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	United States Environmental Protection Agency
EPRI	Electrical Power Research Institute
ER	Enhanced Recovery
FR	Federal Register
GS	Geologic Sequestration
mg/L	Milligram per Liter
MI	Mechanical Integrity
MIT	Mechanical Integrity Test
MPa	Megapascals
NETL	National Energy Technology Laboratory
OGJ	Oil and Gas Journal
pH	Potential for Hydrogen Ion Concentration
PDFs	Probability Density Functions
PISC	Post-Injection Site Care
PRA	Probabilistic Risk Assessment
psig	Pounds per Square Inch Gauge
SACROC	Scurry Area Canyon Reef Operators Committee
SDWA	Safe Drinking Water Act
SDWIS	Safe Drinking Water Information System
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	United States Geological Survey
WAG	Water Alternating Gas

Definitions

Key to definition sources:

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

Administrator means the Administrator of the United States Environmental Protection Agency, or an authorized representative. [1]

Annulus means the space between the well casing and the wall of the borehole; the space between concentric strings of casing; the space between casing and tubing. [2]

Aquifer exemption refers to a special exemption that removes an aquifer or part of an aquifer from SDWA protection when certain requirements (at 40 CFR 146.4) are met to demonstrate that the exempted aquifer does not currently serve as a source of drinking water and has no real potential to be used as a drinking water source in the future.[3]

Area of Review (AoR) means the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review 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. [4]

Brine refers to water that has a quantity of salt, especially sodium chloride, dissolved in it. Large quantities of brine are often produced along with oil and gas.[5]

Carbon dioxide plume means the extent underground, in three dimensions, of an injected carbon dioxide stream.[4]

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process. This subpart [subpart H of 40 CFR 146] does not apply to any carbon dioxide stream that meets the definition of a hazardous waste as defined by RCRA under 40 CFR part 261.[4]

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

Cement means material used to support and seal the well casing to the rock formations exposed in the borehole. Cement also protects the casing from corrosion and prevents movement of injectate up the borehole. The composition of the cement may vary based on the well type and purpose; cement may contain latex, mineral blends, or epoxy.[2]

Class I wells means technologically sophisticated wells that inject wastes into deep, isolated rock formations below the lowermost USDW. Class I wells may inject hazardous waste, non-hazardous industrial waste, or municipal wastewater.[5]

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

Class III wells means wells that inject fluids associated with solution mining of minerals. Mining practices that use Class III wells include, but are not limited to, salt solution mining, in situ leaching of uranium, and sulfur mining using the Frasch process.[5]

Class V wells means wells not included in Classes I to IV and Class VI. Class V wells inject non-hazardous fluids into or above a USDW and are typically shallow, on-site disposal systems; however, this class also includes some deeper injection operations. There are approximately 20 subtypes of Class V wells.[5]

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

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).[3]

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).[4]

Corrective action means the use of Director-approved methods to assure that wells within the area of review do not serve as conduits for the movement of fluids into underground sources of drinking water (USDWs).[4]

Corrosive means having the ability to wear away a material by chemical action. Carbon dioxide mixed with water, for example, forms carbonic acid, which can corrode well materials.[2]

Enhanced Gas Recovery (EGR) means the process of injecting a gas (i.e., carbon dioxide) into a gas-bearing formation to displace available gas to allow it to be produced.[3]

Enhanced Oil Recovery (EOR) means the process of injecting carbon dioxide into an oil reservoir to thin (decrease the viscosity of) extractable oil, which is then available for recovery.[3]

Enhanced Recovery means either enhanced oil recovery or enhanced gas recovery.[3]

Fluid means any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas or other form or state.[1]

Formation or geological formation means a layer of rock that is made up of a certain type of rock or a combination of types.[2]

Geologic dome refers to a geologic formation that is round or oval in shape and resembles an inverted bowl. A geologic dome consists of an anticline that plunges in all directions.[3]

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.[4]

Geologic sequestration project means an injection well or wells used to emplace a carbon dioxide stream beneath the lowermost formation containing a USDW; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at 40 CFR 146.95; or, wells used for geologic sequestration of carbon dioxide that have received an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to 40 CFR 146.4 and 144.7(d). It includes the subsurface three-dimensional extent of the carbon dioxide plume, associated area of elevated pressure, and displaced fluids, as well as the surface area above that delineated region.[4]

Geophysical surveys refers to the use of geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic 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.[3]

Injectate means the fluids injected. For the purposes of the Class VI Rule, this is also known as the carbon dioxide stream.[2]

Injection depth waivers refer to the provisions at 40 CFR 146.95 that allow owners or operators to seek a waiver from the Class VI injection depth requirements for GS to allow injection into non-USDW formations while ensuring that USDWs are protected from endangerment.[3]

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 geologic sequestration project.[4]

Injectivity refers to the efficiency of displacement of an injected fluid into porous rock, both within the rock (micro-displacement efficiency) as well as from the perspective of total pore space (sweep efficiency).[3]

Lithology means the description of rocks, based on color, mineral composition, and grain size.[5]

Logging means the measurement of physical properties in or around the well.[3]

Mechanical integrity (MI) means the absence of significant leakage within the injection tubing, casing, or packer (known as internal mechanical integrity), or outside of the casing (known as external mechanical integrity).[2]

Mechanical integrity test (MIT) refers to a test performed on a well to confirm that a well maintains internal and external mechanical integrity. MITs are a means of measuring the adequacy of the construction of an injection well and a way to detect problems within the well system.[2]

Miscible refers to a term used to describe phases that can be combined to form a homogenous mixture. Immiscible phases cannot be combined to form a homogenous mixture.[3]

Model means a representation or simulation of a phenomenon or process that is difficult to observe directly or that occurs over long time frames. Models that support GS can predict the flow of carbon dioxide within the subsurface, accounting for the properties and fluid content of the subsurface formations and the effects of injection parameters.[2]

Multiphase flow refers to flow in which two or more distinct phases are present (e.g., liquid, gas, supercritical fluid).[3]

Packer means a mechanical device that seals the outside of the tubing to the inside of the long string casing, isolating an annular space.[2]

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.[3]

Portland cement refers to a hydraulic cement made by reacting a pulverized calcium silicate hydrate material (C-S-H), which in turn is made by heating limestone and clay in a kiln, with water to create a calcium silicate hydrate and other reaction products.[3]

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.[4]

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.[4]

Primacy (primary enforcement responsibility) means the authority to implement the UIC Program. To receive primacy, a state, territory, or tribe must demonstrate to EPA that its UIC program is *at least as stringent* as the federal standards; the state, territory, or tribal UIC requirements may be more stringent than the federal requirements. (For Class II, states must demonstrate that their programs *are effective* in preventing pollution of USDWs.) EPA may grant primacy for all or part of the UIC Program, e.g., for certain classes of injection wells.[5]

Site closure means the point/time, as determined by the 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.[4]

Supercritical fluid: A fluid above its critical temperature (31.1^{o}C for carbon dioxide) and critical pressure (73.8 bar for carbon dioxide).[5]

Total dissolved solids (TDS) refers to the measurement, usually in mg/L, for the amount of all inorganic and organic substances suspended in liquid as molecules, ions, or granules. For injection operations, TDS typically refers to the saline (i.e., salt) content of water-saturated underground formations.[2]

Transmissive fault or fracture means a fault or fracture that has sufficient permeability and vertical extent to allow fluids to move between formations.[4]

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

Underground Injection Control 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 wells injection. This includes setting the federal minimum requirements for construction, operation, permitting, and closure of underground injection wells.[3]

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.[5]

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.[1]

Water alternating gas refers to an enhanced oil recovery technique used to increase oil yields from a reservoir that involves alternating between periods of water and gas (i.e., carbon dioxide) injection.[3]

Waterflooding refers to a secondary recovery technique using the injection of water.[3]

Well bore refers to the hole that remains throughout a geologic (rock) formation after a well is drilled.[3]

Wireline refers to a wire or cable used to lower tools and instruments into a well.[3]

Workover refers to any maintenance activity performed on a well that involves ceasing injection or production and removing the wellhead.[3]

1 Introduction

The Underground Injection Control (UIC) Program of the United States Environmental Protection Agency (EPA) is responsible for establishing regulations for the construction, operation, permitting and closure of injection wells through which fluids are placed underground. EPA's regulations, at Title 40 of the Code of Federal Regulations (CFR) Parts 144 through 148, establish six classes of injection wells, based on the type of injection activity and types of fluids injected. Class II injection wells (formally defined at 40 CFR 144.6) are wells into which fluids associated with oil and gas production are injected, including carbon dioxide injected for the purpose of enhanced recovery (ER). The EPA rule *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* [40 CFR 146.81 *et seq*.], referred to in this document as the Class VI Rule, created a new UIC injection well category, Class VI, specifically for the injection of carbon dioxide for the purpose of geologic sequestration (GS).

Carbon dioxide is currently injected into some oil and gas reservoirs for the purpose of increasing or enhancing the recovery of oil and gas. Injection wells used for enhanced oil recovery (EOR) or enhanced gas recovery (EGR) are collectively referred to as ER wells. ER wells have traditionally been regulated under the UIC Program as Class II wells. The Class VI Rule requires that owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI GS permit when there is an increased risk of endangerment to underground sources of drinking water (USDWs) compared to Class II operations [40 CFR 144.19(a)].

EPA recognizes that it is very likely that some carbon dioxide will be trapped in the subsurface as part of ER operations; however, if there is no increased risk to USDWs, then these operations would continue to be permitted under Class II requirements. Traditional EOR projects are not affected by the Class VI rulemaking and will continue to be permitted under Class II requirements. The Class VI Rule lists several factors that the UIC Program Director must consider to determine if risks to USDWs have increased and a Class VI permit is required [40 CFR 144.19(b)].

This document is designed to provide guidance to injection well owners or operators and UIC Program Directors regarding when Class II operations must be re-permitted as Class VI wells. This document is part of a series of technical guidance documents intended to provide information and possible approaches for addressing various aspects of permitting and operating a Class VI injection well. The Class VI 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. Cross-linkages between guidance documents are noted in the text where appropriate. These additional UIC Program GS guidance documents can be found at http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm.

1.1 Comparison of Class II and Class VI UIC Regulations

When an injection well operation transitions from a Class II to a Class VI well, the well owner or operator must comply with all Class VI requirements. There are, however, certain components of Class II well construction that may be grandfathered into the Class VI Program at the discretion of the Class VI UIC Program Director [40 CFR 146.81(c)]. While the Class II requirements are designed specifically to protect USDWs from injection activities conducted for ER and brine disposal, the Class VI Rule is designed to protect USDWs from carbon dioxide injection associated with GS projects. The Class VI requirements build on existing UIC requirements, including those for Class II, and are tailored for the unique circumstances of GS through additional requirements, such as post-injection site care (PISC).

The nature and risks of carbon dioxide injection for long-term storage into Class VI wells are different from those at Class II carbon dioxide injection wells used for EOR. For example, reservoir pressure conditions and injection rates and volumes will be different between Class II and Class VI. Additionally, the corrosivity of carbon dioxide in the presence of water necessitates additional protective measures that are not required of Class II owners or operators.

A summary comparison of Class II and Class VI requirements is provided in Table 1, and a more detailed comparison is provided in Appendix I. The Class VI requirements are more comprehensive and specific than the Class II requirements. For instance, the area of review (AoR) delineation requires sophisticated modeling for Class VI [40 CFR 146.84(c)(1)], whereas the AoR for Class II operations may be delineated using a fixed radius or a radial calculation, although an owner or operator may use more sophisticated modeling depending on the Class II operation [40 CFR 146.6]. Well construction standards are more specific for Class VI, and more frequent mechanical integrity (MI) testing of the Class VI wells is required [40 CFR 146.89 and 40 CFR 146.90(e)]. Additionally, monitoring of ground water quality and tracking the fate of the injectate and induced pressure front are required under the Class VI Program [40 CFR 146.90(d)], but not the Class II program. Post-injection monitoring is also required only under the Class VI Program [40 CFR 146.93(b)]. Multiple Class II wells within a single field may be permitted on a field-basis through the use of a single "area permit." Area permits are not allowed for Class VI wells; instead, each Class VI well in a given field or site must be permitted individually [40 CFR 144.33(a)(5)].

The Class VI Program is implemented under Section 1422 of the Safe Drinking Water Act (SDWA), which mandates that states seeking primary enforcement responsibility (primacy) meet all minimum federal requirements for protection of USDWs by developing and implementing a UIC Program with requirements that meet the minimum federal requirements. Class II Programs, however may be implemented under Section 1422 or Section 1425 of the SDWA. Programs implemented under Section 1425 are required to demonstrate an effective Class II Program for preventing underground injection that endangers USDWs. (Class II Programs implemented under Section 1422 must have Class II regulations that are at least as stringent as the federal Class II regulations.)

The more comprehensive and specific requirements of the Class VI Program (as compared to the Class II Program requirements) reflect the unique potential risks posed to USDWs by GS. EPA anticipates that the injection pressures and injected carbon dioxide volumes will be greater for commercial-scale GS projects than for ER projects, resulting in larger project areas, increased project duration, and, therefore, a greater potential for risk of endangerment to USDWs.

Table 1. Comparison of Requirements for Class II and Class VI Wells.

Requirement Type	Class VI Regulatory Citations	Class II Requirements (Summary) and Regulatory Citations	Significant Differences between Class II and Class VI Requirements
Required Class VI permit information	40 CFR 146.82	Information is required on the local geology. The UIC Program Director may consider information including maps and cross sections of the regional geology, including the AoR; the planned formation testing program, construction, operating and monitoring procedures; and a demonstration of financial responsibility to close the well. (40 CFR 146.24)	Class VI regulations require information on baseline geochemistry and seismic history. Class VI requirements include several project-specific plans not required for Class II (e.g., post-injection site care and site closure and comprehensive Emergency and Remedial Response Plans). Class VI requirements include periodic updates to certain plans.
Minimum criteria for siting	40 CFR 146.83	Demonstrate the presence of injection and confining zones. Confining zone must be free of known open faults or fractures within the AoR. (40 CFR 146.22)	Class VI regulations permit the UIC Program Director to require characterization of additional confining zones.
Area of review and corrective action	40 CFR 146.84	Define the AoR as a fixed radius of at least ¼ mile or based on the zone of endangering influence (calculate by a formula). (40 CFR 146.6) For new wells, identify status of corrective action on improperly completed or plugged wells in the AoR. (40 CFR 146.24(c)(6))	Class VI regulations require computational modeling for AoR and periodic reevaluation of the AoR and Corrective Action Plan. Class VI regulations require the use of carbon dioxide-compatible materials for corrective action. Class VI regulations permit phased corrective action.
Financial responsibility	40 CFR 146.85	Demonstrate and maintain financial responsibility to close, plug, or abandon the well. (40 CFR 146.24(a)(9))	Class VI regulations have requirements for financial responsibility to address corrective action, post-injection site care and site closure and emergency and remedial response. Class VI regulations have requirements for allowable instruments.

Requirement Type	Class VI Regulatory Citations	Class II Requirements (Summary) and Regulatory Citations	Significant Differences between Class II and Class VI Requirements
Injection well construction	40 CFR 146.86	Wells must be constructed to prevent movement of fluids into or between USDWs. Casing and cementing must be designed for the life expectancy of the well. (40 CFR 146.22)	Class VI regulations specify the depths of casing strings and cementing to the surface*. Class VI regulations require compatibility of well materials with fluids with which they would come into contact.
Logging, sampling and testing prior to injection well operation	40 CFR 146.87	Class II and Class VI regulations include similar requirements for logging, sampling and testing (40 CFR 146.22 (f)).	Class VI regulations require cores to be taken and a log analyst's report to be submitted*. Class VI regulations require tests to verify the hydrogeologic characteristics of the injection zone (e.g., pressure fall-off test and pump test or injectivity tests) *. Class VI regulations require the owner or operator to provide the UIC Program Director the opportunity to witness all logging and testing for a Class VI well.
Injection well operating requirements	40 CFR 146.88	Injection between the outermost casing protecting USDWs and the well bore is prohibited. (40 CFR 146.23(a)(2)) Injection pressures may not initiate or propagate fractures in the confining zone or cause injection or formation fluid movement into USDWs. (40 CFR 146.23(a)(1))	Class VI regulations include a pressure limitation. Class VI regulations include a requirement to install continuous recording devices, alarms and surface or down-hole shut-off systems or other safety devices. Class VI regulations require specific procedures if a loss of mechanical integrity is discovered or a shutdown (i.e., down-hole or at the surface) is triggered.
Mechanical integrity testing	40 CFR 146.89	Conduct internal and external MITs at least once every five years. (40 CFR 146.23(b)(3))	Class VI regulations require continuous monitoring to demonstrate internal mechanical integrity. Class VI regulations require annual external mechanical integrity testing.

Requirement Type	Class VI Regulatory Citations	Class II Requirements (Summary) and Regulatory Citations	Significant Differences between Class II and Class VI Requirements
Testing and monitoring requirements	40 CFR 146.90	Monitor injected fluids. Observe injection pressure, flow rate and cumulative volume on a daily, weekly or monthly basis, depending on the type of operation. (40 CFR 146.23(b)(1-2))	Class VI regulations require: • Continuously monitoring of injected fluids, injection pressure, flow rate and cumulative volume; • Plume and pressure front tracking; • Surface air monitoring and soil monitoring, at the UIC Program Director's discretion; and • Corrosion monitoring and ground water quality monitoring.
Reporting requirements	40 CFR 146.91	Submit annual monitoring report. (40 CFR 146.23(c))	Class VI require: • Semi-annual monitoring report; • Electronic reporting; and • Record-keeping.
Injection well plugging	40 CFR 146.92	Well must be plugged in a manner which will not allow the movement of fluids either into or between a USDW. (40 CFR 146.10(a)(1))	Class VI regulations require compatibility of the plugging material with fluids with which the plugs may be expected to come into contact. Class VI regulations specify pre-plugging activities, notice of intent to plug and a plugging report.
Post-injection site care and site closure	40 CFR 146.93	None.	Class VI regulations require post-injection site care or monitoring; no such requirements exist for Class II.
Emergency and remedial response	40 CFR 146.94	Submit contingency plans to cope with well failures so as to prevent migration of fluids into a USDW. (40 CFR 146.24(b)(4))	Class VI regulations address other potential risks in the AoR, such as risks from the pressure front.

*Pursuant to requirements at 40 CFR 146.81(c), owners or operators seeking to convert existing wells to Class VI geologic sequestration wells must demonstrate to the UIC Program Director that the wells were engineered and constructed to meet the requirements at 40 CFR 146.86(a) and ensure protection of USDWs, in lieu of requirements at 40 CFR 146.86(b) and 146.87(a). See Section 4 of this guidance for additional information on requirements for transitioning wells.

1.2 Re-permitting of Class II Wells

As noted above, owners or operators of existing Class II injection wells that inject carbon dioxide into an oil or gas reservoir for the primary purpose of long-term storage of carbon dioxide must apply for and secure a Class VI permit when there is an increased risk to USDWs compared to Class II operations [40 CFR 144.19(a)]. The Class VI UIC Program Director must determine, based on review of information provided by the owner or operator and the factors at

40 CFR 144.19(b), when there is an increased risk to USDWs (see Section 3). EPA anticipates that such an evaluation may be initiated by an owner or operator, suggested by a Class II UIC Program Director based on an evaluation of the factors at 40 CFR 144.19, or may be requested by the Class VI Program Director as a result of periodic evaluations of information on wells in mature oil and gas fields in the context of the factors at 40 CFR 144.19. Several options are available to facilitate the request for and evaluation of site-specific information (e.g., monitoring data) about Class II ER operations that is needed to evaluate the factors at 40 CFR 144.19(b):

- 40 CFR 144.17 provides either the Class II or Class VI UIC Program Director with the authority to require that a Class II owner or operator "conduct monitoring, and provide other information as is deemed necessary to determine whether the owner or operator has acted or is acting in compliance with Part C of the SDWA or its implementing regulations." This could include requesting information needed to determine whether the injection may lead to an increased risk to USDWs relative to Class II operations.

- 40 CFR 144.51(h) requires permittees to provide "any information which the Director may request to…determine compliance with [a] permit." This gives the Class II UIC Program Director the authority to include Class II permit provisions to gather information that may be needed in the future to determine whether the project meets the definition of a Class II well or whether re-permitting as a Class VI well is necessary.

- 40 CFR 144.52(a)(9) gives the Class II permit writer authority to "impose on a case-by-case basis such additional conditions as are necessary to prevent the migration of fluids into underground sources of drinking water." This may include the Class II UIC Program Director requesting monitoring or other information needed to support an evaluation of the factors at 40 CFR 144.19(b) on behalf of the Class VI UIC Program Director. If the Class II owner or operator plans to eventually transition to GS, the Class II UIC Program Director may use authority at 40 CFR 144.52(a)(9) to guide the monitoring and reporting conditions of the Class II permit to allow collection of necessary information.

The review of site-specific information and evaluation of the factors at 40 CFR 144.19(b) by the Class VI UIC Program Director may take place in consultation with the Class II UIC Program Director and the owner or operator. Consultation and coordination between Class II and Class VI permitting authorities may be needed, particularly where they are with different organizations (e.g., where two different state agencies have Class II and Class VI primacy or where the state has Class II Program primacy and the Class VI Program is directly implemented by EPA) or when permitting of Class II and Class VI wells in a state is under different authorities (e.g., the state has primacy for Class II wells under SDWA Section 1425 and Class VI wells under SDWA Section 1422). EPA recommends that states work across agencies, with EPA regional staff and with owners or operators as appropriate to facilitate the transfer of relevant information about a site and ensure that all existing data about a site and an owner or operator are available to the Class VI permit writer.

Following a determination that the well must be re-permitted as a Class VI well, the owner or operator of a re-permitted injection well must meet all Class VI requirements. However, under

40 CFR 146.81(c), the UIC Program Director has the option to grandfather the construction of existing wells to be re-permitted as Class VI if the owner or operator demonstrates to the UIC Program Director that the wells were engineered and constructed to meet the requirements at 40 CFR 146.86(a) and ensure protection of USDWs, in lieu of requirements at 40 CFR 146.86(b) and 146.87(a). See Section 4 of this document and the *UIC Program Class VI Well Construction Guidance* for additional information on grandfathering of Class II wells. Prior to the re-permitting of an existing Class II well, the owner or operator must submit, and the UIC Program Director must consider, all of the permit information at 40 CFR 146.82(a) and (c).

EPA recognizes that some GS project owners or operators may plan to eventually produce the injected carbon dioxide from the injection zone (e.g., to sell it for ER). However, these projects require a Class VI permit. The appropriate injection well class is based on the injection activity and its risk to USDWs, and a Class VI permit is needed to address the potential risk associated with high pressures that will exist in the subsurface during injection and in the early months or years of carbon dioxide withdrawal. Because the high injection rates and pressures associated with GS will cause movement of the carbon dioxide plume—even if the planned withdrawal would occur a few years after injection ceases—a Class VI permit (and the required operational- and post-injection phase monitoring) is needed to address potential risks of USDW endangerment. Injecting carbon dioxide under a Class VI permit will not preclude future withdrawal of the carbon dioxide.

Following re-permitting as a Class VI well, the owner or operator will be subject to all of the operational, testing and monitoring, reporting, injection well plugging and PISC and site closure requirements set forth in 40 CFR 146 Subpart H. For additional information on permitting Class VI wells, see the *UIC Program Class VI Implementation Manual for State Directors.*

1.3 Organization of this Guidance Document

The remaining sections of this guidance document are organized as follows:

- **Section 2, Background on Enhanced Oil and Gas Recovery in the U.S.**, presents background information on carbon dioxide ER operations, potential risks to USDWs, and the phases of a traditional ER project transitioning to GS.

- **Section 3, Factors for Identification of the Need for a Class VI Permit**, describes the factors at 40 CFR 144.19 to be considered by owners or operators and the Class VI UIC Program Director when determining whether a Class VI permit is required for carbon dioxide injection wells currently permitted as Class II wells. These factors include: increase in reservoir pressure; increase in carbon dioxide injection rates; decrease in reservoir production rates; distance between injection zone and USDWs; suitability of Class II AoR delineation; quality of abandoned well plugs; anticipated recovery of injected carbon dioxide at cessation of injection; source and properties of injected carbon dioxide and possibly additional factors determined by the Class VI UIC Program Director.

- **Section 4, UIC Requirements for Wells Transitioning from Class II to Class VI**, describes well construction for Class II wells and additional Class VI requirements that owners or operators must meet following a determination that a Class II ER project will transition to a Class VI GS project [40 CFR 146.86 and the construction-related requirements at 40 CFR 146.87(a)]. These additional requirements include well construction requirements as well as operating-phase requirements and individual well permitting requirements for Class VI wells.

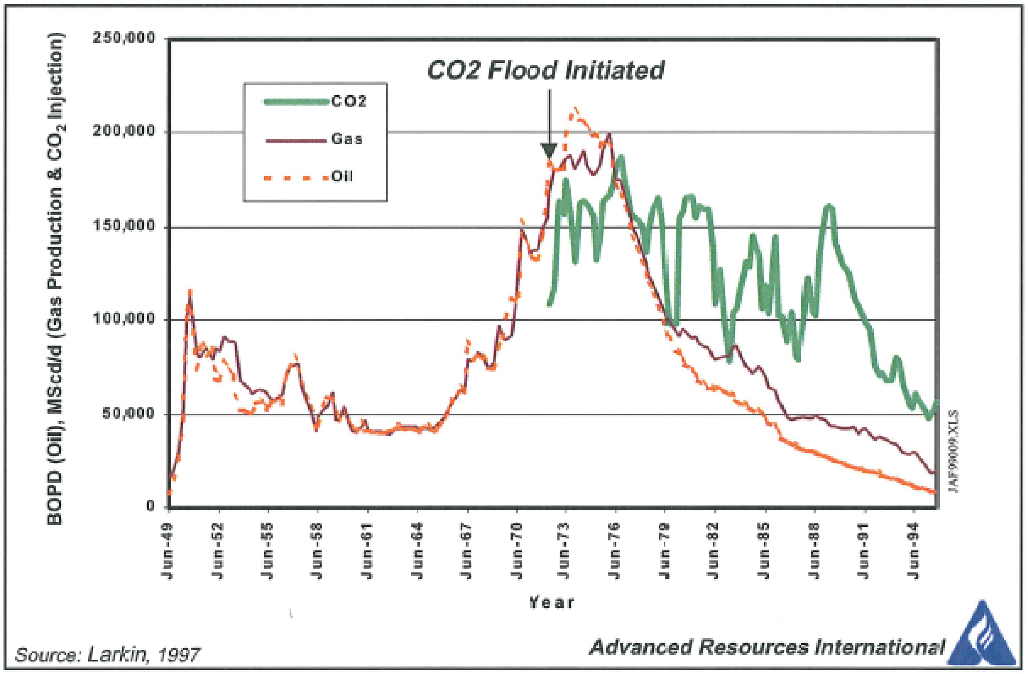
- **Section 5, Transitioning Wells and Aquifer Exemptions**, describes how owners or operators of Class II ER projects that currently operate under an aquifer exemption can apply to expand the areal extent of the aquifer exemption pursuant to the requirements of 40 CFR 144.7(d). The relationship between aquifer exemptions and injection depth waivers for GS projects is also briefly discussed.

2 Background on Enhanced Oil and Gas Recovery in the U.S.

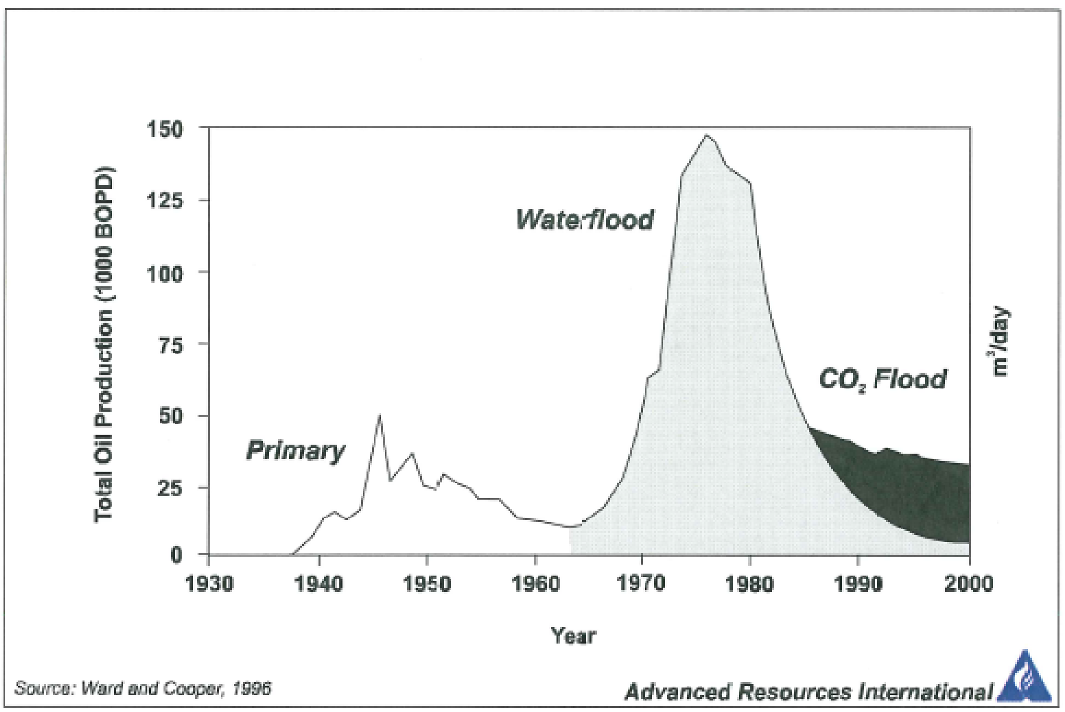
ER, which includes both EOR and EGR, refers to the injection of fluids into a reservoir to increase oil and/or gas production efficiency. ER is typically conducted at a reservoir after production yields have decreased from primary production—during primary oil production, no fluids are injected into the reservoir to enhance production. Fluids commonly used for ER include brine, fresh water, steam, nitrogen, alkali solutions, surfactant solutions, polymer solutions and supercritical carbon dioxide. EOR involves injecting carbon dioxide or another fluid into an oil reservoir to help mobilize the remaining oil and make it available for recovery; EGR refers to injecting a gas (e.g., carbon dioxide) into a gas-bearing formation to displace available gas to allow it to be produced. ER using supercritical carbon dioxide, sometimes also referred to as carbon dioxide flooding, has been successfully used at many production fields throughout the U.S. (and abroad) to increase recovery. For example, Figure 1 presents production data from two fields in the Permian Basin, Texas, showing increased oil production volumes following EOR with carbon dioxide.

Carbon dioxide EOR is the fastest-growing EOR technique in the U.S., producing 323,000 barrels of oil per day (BOPD) in 2004. This comprises about 6.5 percent of U.S. crude oil production (OGJ, 2008; EIA, 2009). The vast majority of worldwide carbon dioxide EOR is conducted in oil reservoirs in the U.S. Permian Basin, which extends through southwest Texas and southeast New Mexico. The majority of these projects are located in Texas, and the remaining projects are located in Mississippi, Wyoming, Michigan, Oklahoma, New Mexico, Utah, Louisiana, Kansas and Colorado (see Figure 2).

EPA believes many early GS projects may be sited in depleted, depleting, or active oil and gas reservoirs because these formations have been previously characterized for hydrocarbon recovery and likely already have suitable infrastructure (e.g., wells, pipelines, etc.). EPA expects that these early projects will support meeting near-term greenhouse gas mitigation goals and advance CCS technology development. Additionally, oil and gas fields now considered to be "depleted" may resume operation because of increased availability and decreased cost of anthropogenic carbon dioxide (NETL, 2010). Current Department of Energy (DOE) projections of areas where GS may occur in oil and gas reservoirs are included in Figure 2. Anticipated regions of interest primarily include Louisiana, Texas, Oklahoma, Kansas, New Mexico, Colorado, Wyoming, California, Montana, North Dakota, West Virginia and Ohio.



(a)



(b)

Figure 1. Graphs of Oil Production Rates during Primary Production, Waterflooding and ER with Carbon Dioxide (i.e., Carbon Dioxide Flooding) for (a) the SACROC Unit and (b) Denver Unit in the Permian Basin, Texas.
From: EPRI (1999).

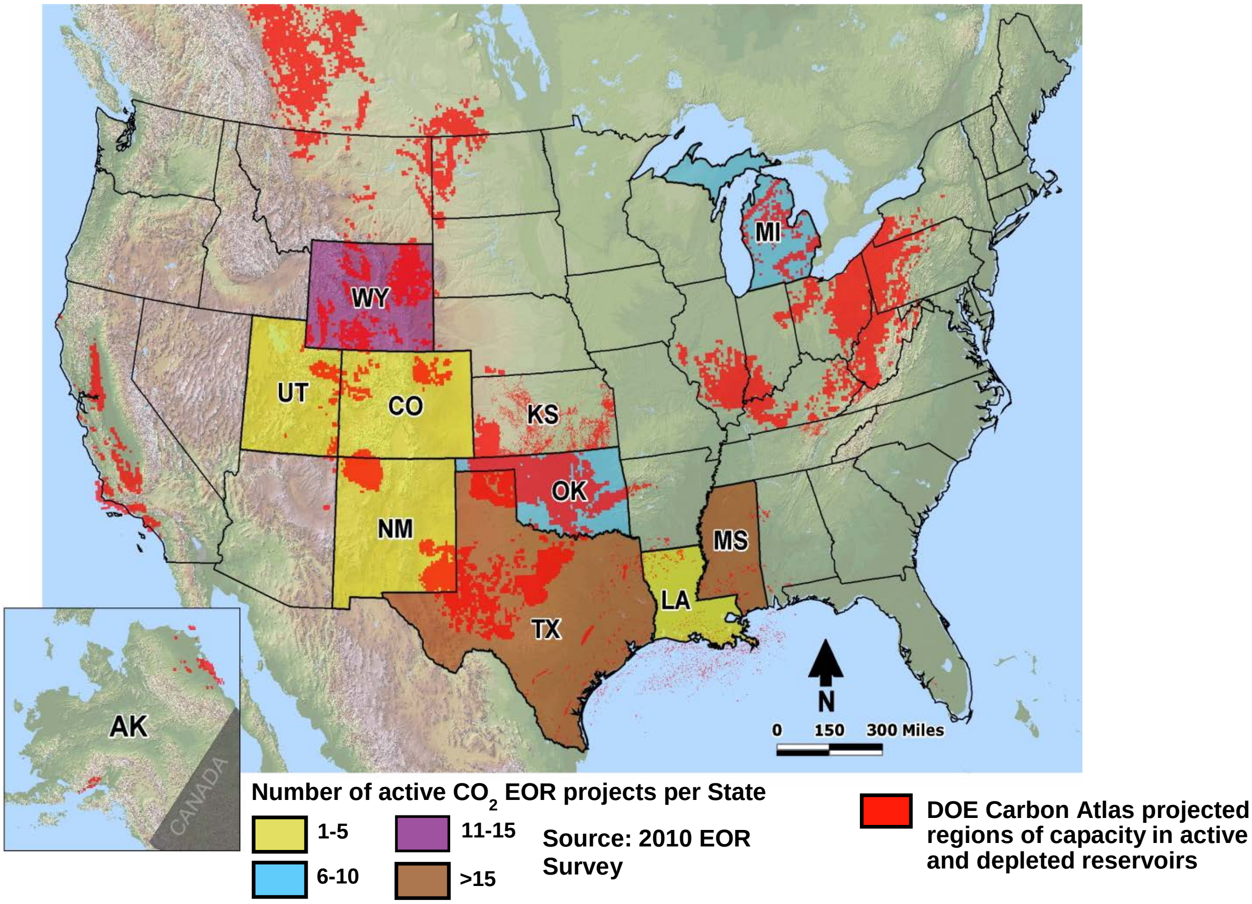


Figure 2. Number of Active Carbon Dioxide EOR Projects per State (as of 2008) and DOE Anticipated Regions for GS in Oil and Gas Reservoirs.
From: DOE (2010).

2.1 Carbon Dioxide Enhanced Recovery Operating Practices

EOR with carbon dioxide increases the rate of production via miscible displacement, through which the mobility of the residual oil in the reservoir is increased. The improved recovery is due primarily to elimination of surface tension between supercritical carbon dioxide and the liquid phase hydrocarbon in the reservoir. Secondary effects of the miscible carbon dioxide-oil interaction include increase in the specific volume of the oil phase and a reduction in viscosity, both of which improve mobility of the oil phase relative to the water phase and result in an increase in recoverable hydrocarbon. ER can also occur through immiscible displacement, in which the carbon dioxide displaces the oil as an immiscible fluid. Immiscible displacement occurs at shallower depths and lower pressures than miscible displacement. Figure 3a presents a schematic of a generalized carbon dioxide EOR project. Carbon dioxide, provided either from a pipeline or other conveyance or stored on-site, is compressed to a supercritical state (if necessary) and injected into the oil-producing formation (i.e., injection zone). Production wells in the vicinity of the carbon dioxide injection well extract a fluid mixture that may contain injection fluids (e.g., carbon dioxide, water) and formation fluids (e.g., water, oil, solids and natural gas). A series of above-ground separators are then used to separate out the carbon dioxide, which is commonly recycled and re-injected. Oil, natural gas, solids and water are also separated out. Depending on the volume of carbon dioxide being added to the system, the separated water, which is normally a brine (high in salts), is handled in one of two ways: either (1) it is re-injected through a Class II well into the reservoir from which it was originally produced, or (2) it is injected into a Class II disposal well into another reservoir that is pressure-isolated from the original reservoir of production. In the case of water-alternating-gas (WAG) operations (Figure 3b), the separated water may be re-injected for EOR purposes through the same injection well system as the carbon dioxide.

The carbon dioxide used for ER may come from natural geologic and/or anthropogenic sources. Representative compositions of carbon dioxide used for ER are given by Meyer (2007). Generally, the composition of carbon dioxide delivered to an ER site is greater than 95 percent carbon dioxide, with other constituents typically including nitrogen, methane and trace amounts of water. After mixing delivered carbon dioxide and recycled carbon dioxide, the injectate composition may vary from 92 percent to 97 percent carbon dioxide. Both the carbon dioxide delivered to the EOR or EGR site and the recycled carbon dioxide contain very low amounts of water vapor to control corrosion. Surface injection pressures for carbon dioxide injection in ER wells are often greater than 2,000 pounds per square inch-gauge (psig) or 138 bars. The maximum injection pressure is determined by the lower of two pressures, either the fracture gradient of the injection formation or confining formation, multiplied by a safety factor of less than 1.0. The surface and bottom hole operating injection pressures are always maintained below this regulatory limit. The actual injection pressures are determined for each well by a technical and economic calculation taking into account reservoir pressure, surface temperature, reservoir temperature, injectate composition, injection rate, reservoir maturity and the regulatory limit. A second, separate safety factor is then utilized to establish a desired routine operating injection pressure and a higher safety shutdown limit, which is also below the regulatory limit.

A primary challenge in EOR is preventing preferential flow, or channeling, of carbon dioxide through high-permeability lenses in the formation, which results in reduced reservoir sweep efficiency and excessive carbon dioxide cycling. To improve sweep efficiency, EOR fields are normally operated with WAG injection, where water and carbon dioxide injection are alternated cyclically (e.g., EPRI, 1999; Meyer, 2007; Jessen et al., 2005); see Figure 3b. Other options to maximize the efficiency and reservoir sweep of the EOR operation are the use of horizontal injection wells, the addition of chemical agents to increase viscosity and reduce viscous fingering, a significant increase in carbon dioxide injection volumes above normal injection rates and innovative well placement designs and targeting of specific zones (e.g., Jessen et al., 2005; ARI, 2006; Meyer, 2007). Carbon dioxide injection wells and oil production wells are sited in patterns frequently repeated throughout the site, designed to maximize oil recovery.

2.2 Potential Risks to USDWs from EOR

The injection of fluids, including carbon dioxide, underground poses potential risks to USDWs. In the context of the UIC Program, the term "risk" refers to the possibility for degradation of water quality in a USDW as it relates to the usability of that USDW as a drinking water source now or in the future. A USDW is considered to be "endangered" if an injection project has caused degradation of water quality. There are several ways in which such degradation might occur in a GS project:

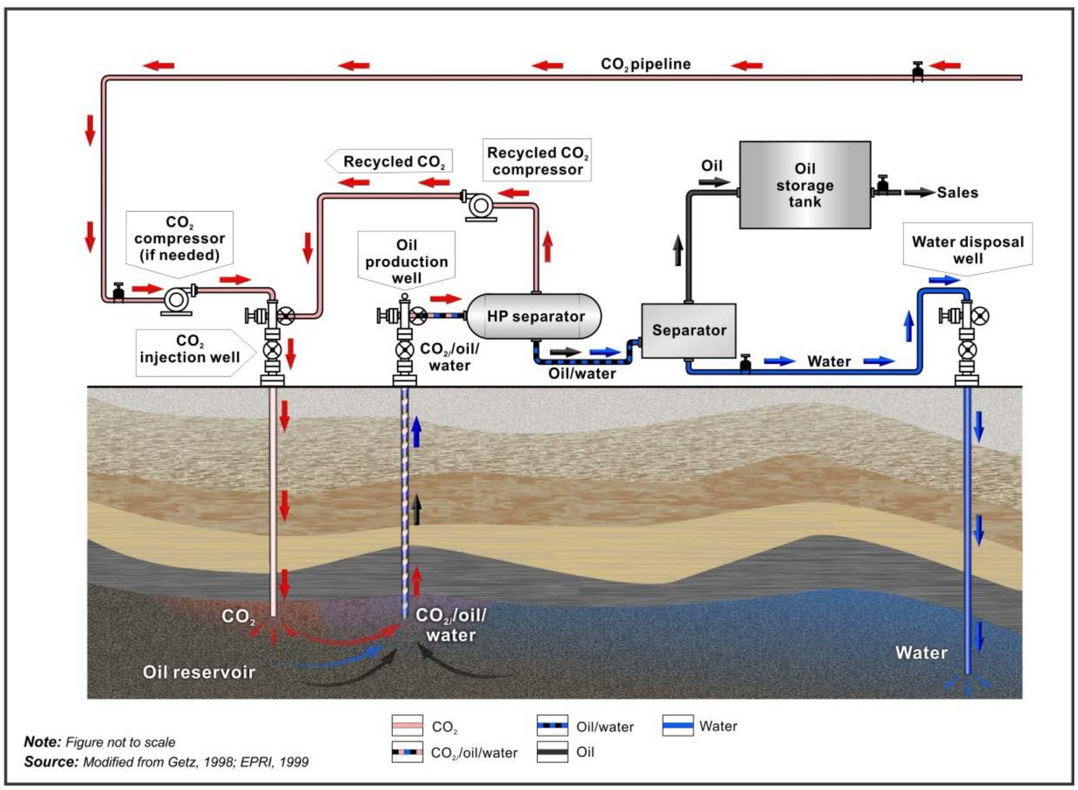
- Migration of carbon dioxide into a USDW, which may change geochemical characteristics of the USDW, including decreased pH and consequent leaching of natural minerals to release contaminants (e.g., lead and arsenic) into the USDW;

- Migration of drinking water contaminants transported in the injectate (e.g., hydrogen sulfide and mercury) into USDWs;

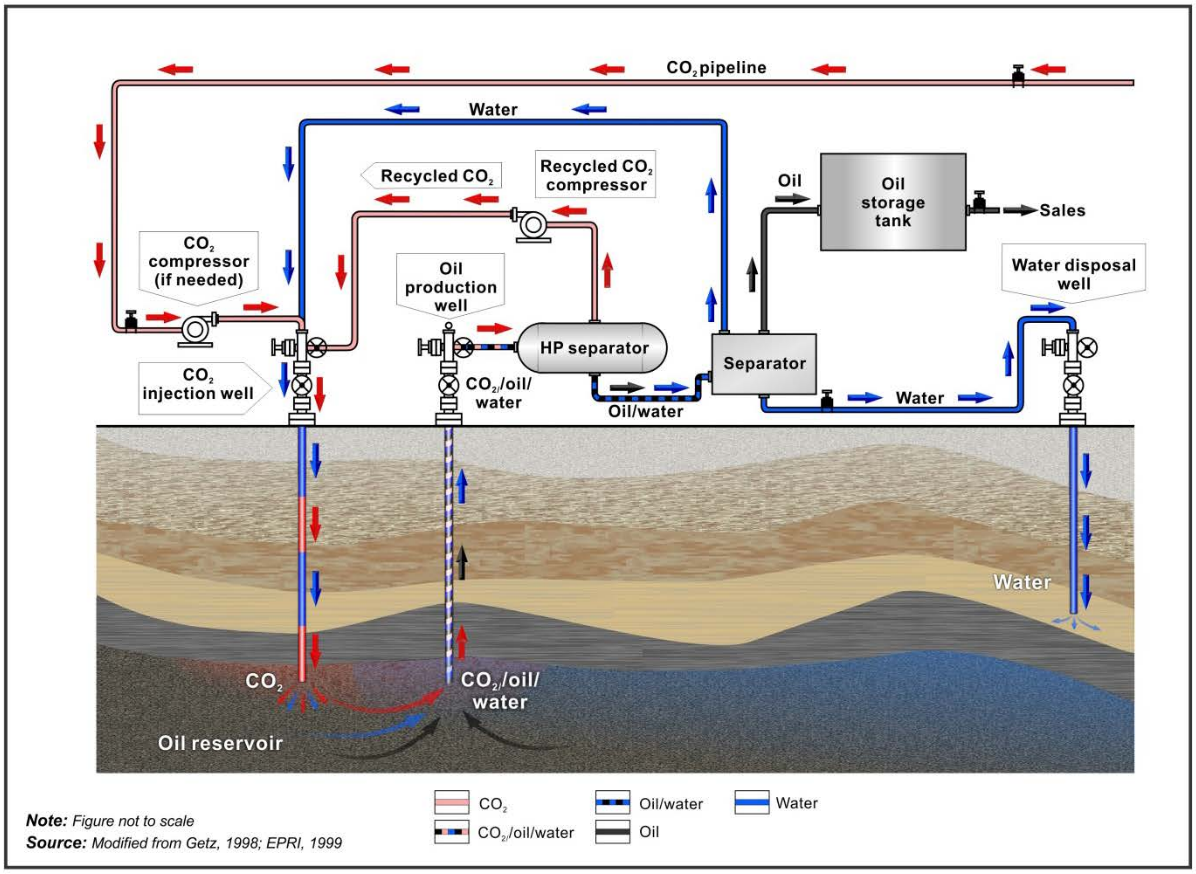
- Change in geochemistry of formation fluids that may cause leaching of drinking water contaminants (e.g., lead and arsenic), which may then migrate into the groundwater of USDWs, impairing drinking water quality; and/or

- Induced migration of non-potable, saline formation fluids from the injection zone, or overlying zones, into a USDW.

EPA designed the Class VI regulations to minimize risks to USDWs that may be posed by GS projects. If GS projects are properly operated in compliance with all Class VI regulations, EPA believes that risks to USDWs will be appropriately managed and USDWs will be protected.



(a)



(b)

Figure 3. Schematic of an EOR Project Showing Carbon Dioxide Injection, Production of Mixed Fluids, Separation and Carbon Dioxide Recycling (a) and a Water-Alternating-Gas Scenario (b).

2.3 Phases of a Hypothetical EOR Project Transitioning to a GS project

As described above, EPA anticipates that for wells injecting carbon dioxide in oil and gas reservoirs for GS, there may be an increased risk to USDWs compared to traditional Class II operations. Figure 4 presents an example of a risk diagram showing relative risk over the different phases of a generic carbon dioxide project. During primary oil production, no fluids are injected into the reservoir to enhance production. The oil and/or gas production rate declines during primary production as the remaining oil in place is more difficult to access and remove. In the example field, first waterflooding and then EOR are employed to increase production rates. Although injection of carbon dioxide increases production efficiency initially, production rates decrease over time. (This trend is shown for actual oil production fields in Figure 1.) In this example, as the owner or operator transitions the primary purpose of his/her project from EOR to GS, there is an increased risk to USDWs when compared to the ER operations, and therefore, the owner or operator should obtain a Class VI permit. During GS, carbon dioxide injection rates increase and fluid production rates continue to decline. At the point when the reservoir has received the maximum practical volume of carbon dioxide, injection ceases. The Class VI GS project continues during PISC and eventually ends with site closure.

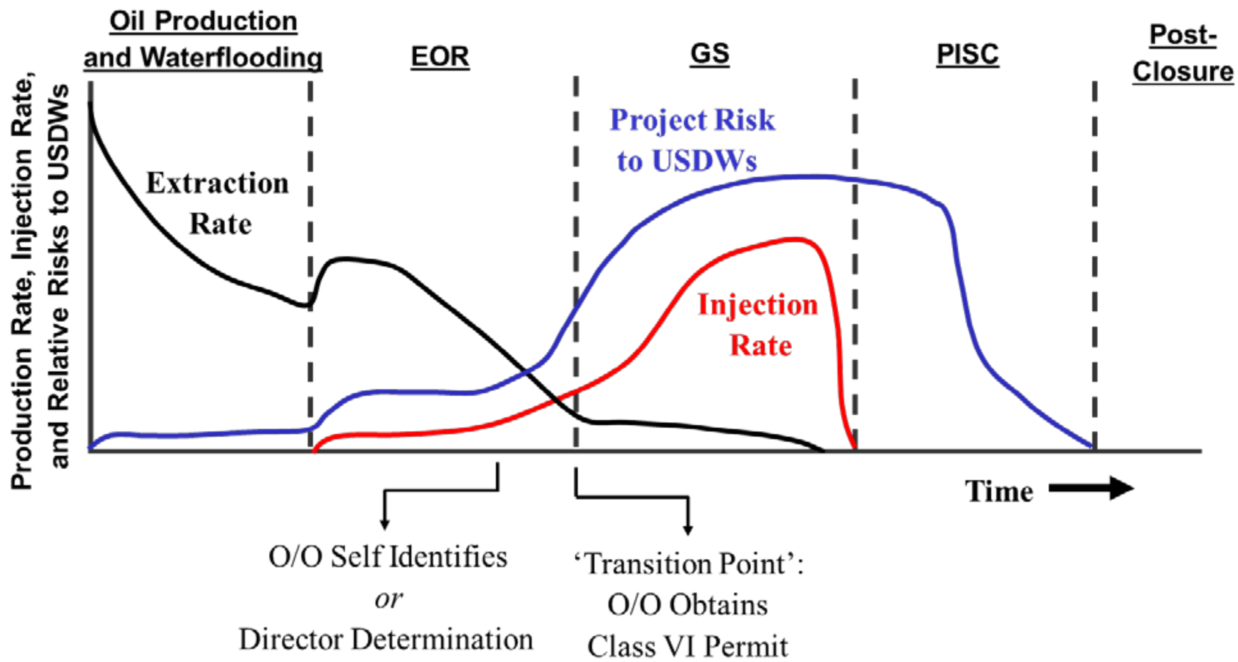


Figure 4. Phases of a Hypothetical Oil Production Project that Transitions to ER and Eventually GS, Illustrating Relative Risk.
From: Benson (2007).

3 Factors for Identifying the Need for a Class VI Permit

Owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI permit when there is an increased risk to USDWs compared to Class II operations [40 CFR 144.19(a)].

This guidance document discusses the "primary purpose" of the injection only as it relates to and supports an identification within EPA's UIC Program of the appropriate UIC well class under which a well injecting carbon dioxide must be permitted. The determination of primary purpose for the UIC well class evaluation may have little or no bearing on how the purpose of the well is defined for other regulatory programs or activities.

The determination of the need for a Class VI permit is based on risk to USDWs. In the Class VI Rule, EPA identified several factors that indicate a change in project operations that may increase risks to USDWs. These factors are to be considered by owners or operators and Class VI UIC Program Directors[1] when determining whether a Class VI permit is required for carbon dioxide injection in wells currently permitted as Class II wells. They may also be considered by owners or operators applying for a permit for a Class II well to inform business decisions prior to deciding whether to permit a well as a Class II or Class VI well. Considering these factors ahead of time may also ease the transition process at a later point in time. These factors are established in the Class VI Rule at 40 CFR 144.19(b), and include:

- Increase in reservoir pressure;
- Increase in carbon dioxide injection rates;
- Decrease in reservoir production rates;
- Distance between injection zone and USDWs;
- Suitability of Class II AoR delineation;
- Quality of abandoned well plugs;
- Anticipated recovery of injected carbon dioxide at cessation of injection;
- Source and properties of injected carbon dioxide; and
- Additional factors determined by the UIC Program Director.

EPA developed these factors to inform a determination regarding whether an increased risk to USDWs warrants re-permitting a project from Class II to Class VI. No single factor from this list should be independently relied upon to make determinations. Rather, all available factors should

[1] The decision to re-permit a Class II well as a Class VI well will benefit from consultation and coordination with the Class II UIC Program Director.

be considered in determining the appropriate well class for a carbon dioxide injection well in an oil and gas reservoir, to the extent possible given information available to the Class VI UIC Program Director. Specific factors are discussed in detail in this section.

EPA recognizes that Class II wells may not necessarily transition to Class VI. This may be because an evaluation of the above factors results in a determination that a Class VI permit is not needed, either because the owner or operator determines that he/she does not want to proceed with or continue carbon dioxide injection and decides to plug the well, or because a determination is made that the Class II well was not sited or constructed in a manner that allows for safe, long-term storage of large volumes of carbon dioxide as a Class VI injector.

EPA encourages owners or operators of ER operations considering a transition to GS to consult with both the Class II and the Class VI UIC Program Directors. Ongoing discussions between all parties will promote communication regarding the appropriate permit for each project and if necessary facilitate the transition from Class II to Class VI. Additionally, this communication may clarify what additional project-specific information (e.g., production rates or any plan for recovery of injectate at the cessation of injection) the Class VI UIC Program Director will need that may not be regularly required of or submitted by Class II owners or operators for Class II ER projects.

Although a formal risk assessment is not required by the Class VI Rule, owners or operators may choose to submit the results of a quantitative risk assessment to complement operational and monitoring data submitted to the Class VI UIC Program Director to inform the considerations at 40 CFR 144.19. One approach to risk assessment is to evaluate features, events and processes (FEPs) of an engineered system that may affect the system's behavior; this approach is used in assessing risks for various engineered systems and is discussed in the context of GS by the Carbon Sequestration Leadership Forum (CSLF, 2009). A database of FEPs can help in using this approach to identify issues for a system (e.g., http://www.quintessa.org/co2fepdb/). For owners or operators seeking to pursue a quantitative probabilistic risk assessment (PRA), the box on the next page provides some background on PRA methods and examples of methods that have been developed for and applied to GS. If a PRA is performed, EPA recommends that owners or operators submit information on their choice of method, information on their input data, including choice of probability density functions (PDFs) for input variables, and detailed information on output, including appropriate graphs and a narrative discussing the results along with any data submitted to the Class VI UIC Program Director.

The remaining sections describe each of the factors at 40 CFR 144.19(b) and provide guidance regarding how the Class VI UIC Program Director may evaluate them.

Probabilistic Risk Assessment

Probabilistic risk assessment (PRA) methods present a way to accommodate the uncertainty inherent in input variables for models evaluating risk (e.g., Nicot et al., 2006). This is especially important in geologic settings, which exhibit inherent variability in physical properties and may be prone to future seismic events with little predictability. PRAs attempt to capture the uncertainty associated with this variability through the use of probability density functions (PDFs). PDFs incorporate a statistical distribution that defines a range of reasonable values for a particular input parameter (i.e., intrinsic permeability) rather than a single "average" value (Deel et al., 2007). PDFs are defined by several statistical parameters, such as the median PDF value and variance. The choice of PDF for a particular parameter at a GS project should be based on available data regarding distribution of the parameter. A PRA may then be performed to estimate the probabilities of various risk exposure scenarios based on the assumed PDFs of the input variables.

In particular, a PRA may take advantage of required data on potential leakage pathways (e.g., faults and well bores), formation properties (e.g., permeability and thickness) and formation fluids (e.g., pressure, velocity and salinity) to demonstrate how this information translates into the likelihood of USDW endangerment. If an owner or operator wishes to perform a risk assessment, EPA recommends that they consider the current state of the science on probabilistic methods that have been developed for and applied to GS. Below are three examples:

- Walton et al. (2004) developed a statistical approach to GS performance and risk and applied it to the Weyburn project. Their model, **CQUESTRA-2** (CQ-2) (LeNeveu et al., 2006), is a semi-analytical model that can be used for both probabilistic and deterministic simulations. A deterministic simulation does not incorporate randomness or variability in input variables; it uses discrete input values and yields a reproducible output. A probabilistic simulation incorporates uncertainty in input through the use of PDFs, as described above. The probabilistic aspect of CQ-2 is handled using a Monte-Carlo (repeated random sampling) simulation plug-in for Microsoft Excel. Variability is expressed in PDFs for porosity, permeability, Darcy flow velocity, well component degradation, leakage processes and other parameters. The model Monte Carlo simulator samples the input variables from their PDFs and the modeling process is applied iteratively.
- Oldenburg et al. (2009) developed an approach termed the **Certification Framework** (CF). The CF uses deterministic models to obtain estimates of leakage from wells and faults. It uses a probabilistic approach to calculate the risk of carbon dioxide or brine reaching an environmental compartment (e.g., a USDW) via a fault or well by estimating: 1) the likelihood of the carbon dioxide reaching a leakage pathway and 2) the likelihood of the pathway intersecting the environmental compartment of concern.
- **The CO2-PEN model** (Stauffer et al., 2006; NETL, 2011) is a system-level model, which incorporates a number of aspects of a GS system. It is built on GoldSim, a commercially available modeling software product. It can be used to coordinate subprograms handling a variety of physical and chemical models, including reservoir simulators. Variables can be passed into and out of the subprograms from the system-level model and CO2-PENS can use Monte-Carlo simulation to develop probabilistic representations of variables of interest. CO2-PENS has been linked to a number of programs, including reactive flow models such as FEHM, TOUGHREACT, and FLOTRAN, as well as PHREEQ-C for geochemical simulations (NETL, 2011).

3.1 Reservoir Pressure, Injection Rate and Production Rate [40 CFR 144.19(b)(1-4)]

Reservoir pressure refers to the pressure of fluids within the oil and/or gas reservoir that constitutes the injection zone. During GS operations, injection zone pressure and carbon dioxide volumes will likely increase if carbon dioxide injection rates increase. Furthermore, the dissipation of reservoir pressure will decrease if fluid production from the reservoir decreases. Although pressure dissipation is likely and common in the early and middle stages of the productive life of a field, pressures may remain elevated even after carbon dioxide injection (and oil production) ceases. Owners or operators may also choose to maximize carbon dioxide storage by using “well pressure control,” a technique that effectively increases the pressure of the reservoir by decreasing production rates (e.g., Kovscek and Cakici, 2005).

Elevated pressure great enough to cause fluid movement past the confining zone or through another potential leakage pathway poses a primary risk factor to USDWs from injection because it may result in unintended fluid migration that endangers USDWs. Thus, monitoring data on the fluid pressure within the injection zone is a direct measure of the risks posed to USDWs by the injection project. Reservoir pressure within the injection zone that is increased and sustained at pressures greater than the routine operating pressure range of the ER project will stress the primary confining zone and well plugs to a greater degree than traditional ER (e.g., Klusman, 2003). Furthermore, active and abandoned well bores are much more numerous at oil and gas fields than at other potential GS sites and may be potential leakage pathways (Celia et al., 2004). An AoR evaluation pursuant to the Class VI requirements at 40 CFR 146.84 is necessary to identify abandoned wells and perform corrective action in accordance with necessary standards to prohibit fluid leakage.

Because of the possibility of elevated pressure, the Class VI UIC Program Director should also evaluate increased carbon dioxide injection and/or decreased hydrocarbon production rates in determining risks to USDWs, as listed at 40 CFR 144.19(b)(2-3), and discussed below.

Increase in Reservoir Pressure [40 CFR 144.19(b)(1)]

Reservoir pressure within the formation is measured from a well that is not injecting or withdrawing fluids for a period of at least several days prior to or at the time of measurement. Pressure is measured by monitoring instruments known as pressure transducers, or gauges, which are discussed in detail in the *UIC Program Class VI Well Testing and Monitoring Guidance*. Pressure measurements can be compared to historical pressure levels and fluctuations to gain further understanding of the baseline conditions. Trends over time of significantly increasing pressure for extended duration, (i.e., greater than six months to one year), considered in conjunction with other factors listed in this section, indicate that a Class VI permit may be required.

Specifically, increased pressures within the injection zone should be compared against the threshold pressure at which fluids are predicted to migrate from the injection zone to the lowermost USDW through a hypothetical open conduit. The pressure threshold within the injection zone that may cause fluid movement into a USDW ($P_{i,f}$) may be determined by the following equation:

$$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) \qquad [1]$$

Where P_u is the average fluid pressure within the lowermost USDW, ρ_i is the density of groundwater within the injection zone, g is a constant for the acceleration due to gravity, and z_u and z_i are the elevations of the USDW and injection zone, respectively, relative to a common datum (e.g., mean sea level). A pressure increase within the injection zone greater than $P_{i,f}$ indicates that the risk to USDWs has increased. Importantly, Eq-1 is only valid in cases where the injection zone is not overpressured relative to the lowermost USDW. Reservoirs that have been previously subjected to ER operations will, in most cases, meet this assumption. Further discussion of threshold pressure calculations are provided in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*.

It should be noted that the hypothetical open conduit assumption is presented as a conservative scenario. In an appropriately sited GS project with suitable corrective action, there should not be direct communication between the injection zone and a USDW through an open conduit. Alternative methods may be used to estimate the threshold pressure in overpressured formations. More detailed methods for assessment of the critical pressure may be used that account for salinity and temperature gradients (e.g., Nicot et al., 2006). Additional site-specific circumstances may influence the assumptions used in calculation of the critical threshold pressure, and the Class VI UIC Program Director may be consulted for evaluation of alternative assumptions and methodologies. An example of the anticipated increase in injection zone pressure with transition to GS is provided in Box 1. Reservoir pressure is commonly monitored during ER operations, but reporting (as a Class II well owner or operator) to the Class II UIC Program Director may not be required, as monitoring and reporting of reservoir pressure is not a Class II federal permit requirement [40 CFR 146.23]. However, pursuant to the requirements at 40 CFR 144.52(a)(9), the Class II UIC Program Director may request pressure data from Class II well owners or operators to evaluate risks to USDWs, especially in projects of dual purposes such as ER and GS. Additionally, on a project-specific basis, the Class VI UIC Program Director may request information pursuant to 40 CFR 144.17 to inform a transition decision. The amount, format and specific types of data requested are based on the UIC Program Director’s discretion and project details.

Box 1: Example of Determining Pressure Changes

This section presents examples of pressure changes in a hypothetical formation. The graphs presented are hypothetical examples, displaying pressure changes as influenced by projected injection and production rates. For actual projects, projected pressure changes may be estimated via analytical, semi-analytical, or numerical modeling techniques based on available site data (see e.g., Zhou et al., 2008, Nicot et al., 2008; Nordbotten et al, 2004; Doughty et al., 2007).

A simple hypothetical formation is presented in Figure 5. In this formation, a single large confining unit separates the injection zone and an overlying USDW. Initial hydraulic head (h_{int}), before any injection or production, is 1,700 meters (m) in the injection zone and 1,900 m in the USDW, corresponding to initial fluid pressures of 6.72 and 0.49 mega-Pascals (MPa), respectively. Initial pressures in the injection zone are great enough to force native fluids vertically upwards through a potential conduit (e.g., abandoned well bore) but not great enough to force fluid vertically upwards to the height of the USDW.

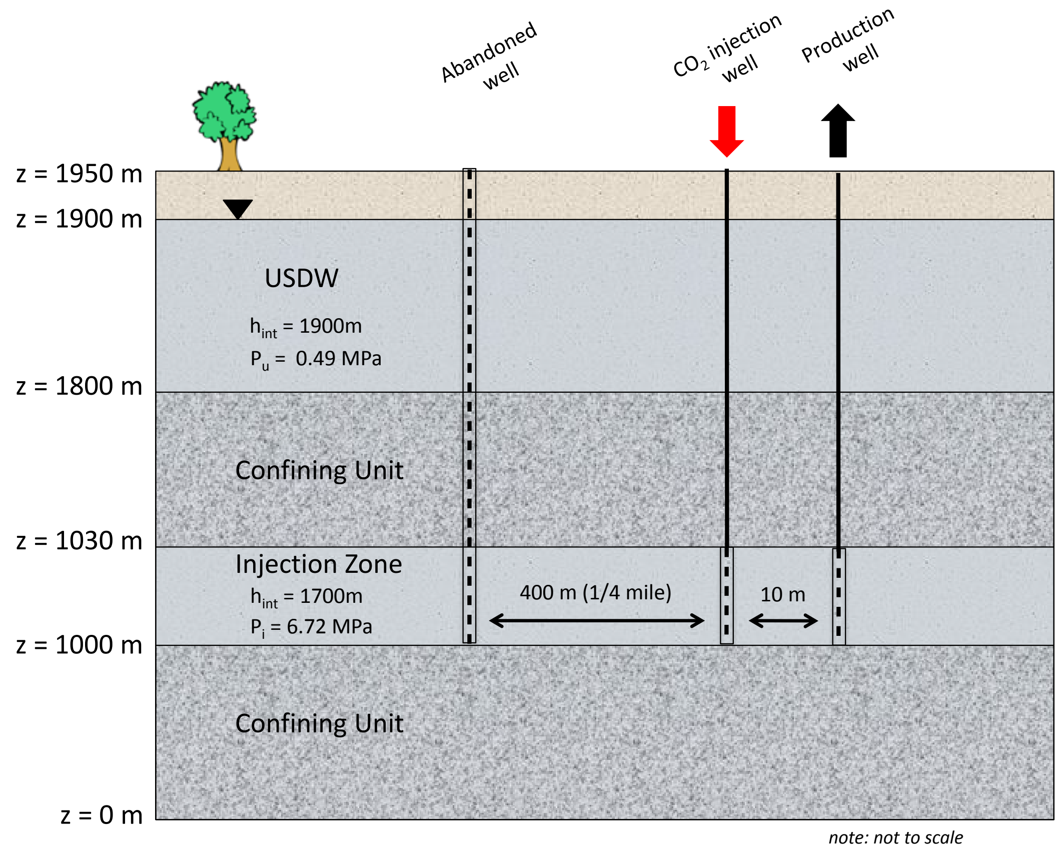


Figure 5. Hypothetical Carbon Dioxide Injection Project Schematic.

The perforated interval of the injection and production wells is depicted by dashed zones. The abandoned well is assumed to be uncased, and therefore open, along its entire depth.

Box 1, *continued*: Example of Determining Pressure Changes

Pressure (e.g., hydraulic head) in the injection zone is a function of injection and production rates, distance from injection and extraction wells, time after initiation of injection and production, as well as the aquifer properties of the injection zone.

For the present example exercise, four injection/production scenarios are evaluated:

- Scenario 1: Oil production without carbon dioxide injection.
- Scenario 2: Oil production with low carbon dioxide injection.
- Scenario 3: Oil production with high carbon dioxide injection.
- Scenario 4: Carbon dioxide injection without oil production.

Specific injection and extraction rates for each of these scenarios are presented in the following table:

	Injection Rate m^3/d	Production Rate m^3/d
Scenario 1	0	3000
Scenario 2	3000	3000
Scenario 3	4000	1000
Scenario 4	4000	0

The scenarios are designed such that Scenario 1 is strictly oil production, and Scenario 4 is strictly GS, while Scenario 2 and Scenario 3 represent ER projects that are transitioning to GS and therefore must be evaluated for the necessity of a Class VI permit. In the example, injection zone pressure increases from Scenario 1 to Scenario 4.

When pressure in the injection zone increases such that hydraulic heads within the injection zone are greater than hydraulic heads in the lowermost USDW, fluids in the injection zone could potentially be pushed into the USDW via an artificial penetration, fault, or fracture system. The pressure threshold that defines risk of fluid flow from the injection zone to the lowermost USDW is calculated with Equation 1. For this example, the injection zone threshold pressure ($P_{i,f}$) is 8.68 MPa. Pressure increases will be greatest at the injection well and decrease exponentially as distance from the injection well (r) increases. In the example, it is assumed that adequate protections exist at the injection well to preclude fluid movement through or around the well bore, and the artificial penetration at a distance of 400 meters (approximately 1/4 mile) from the injection well is the relevant measurement point for pressure increase.

Box 1, *continued*: Example of Determining Pressure Changes

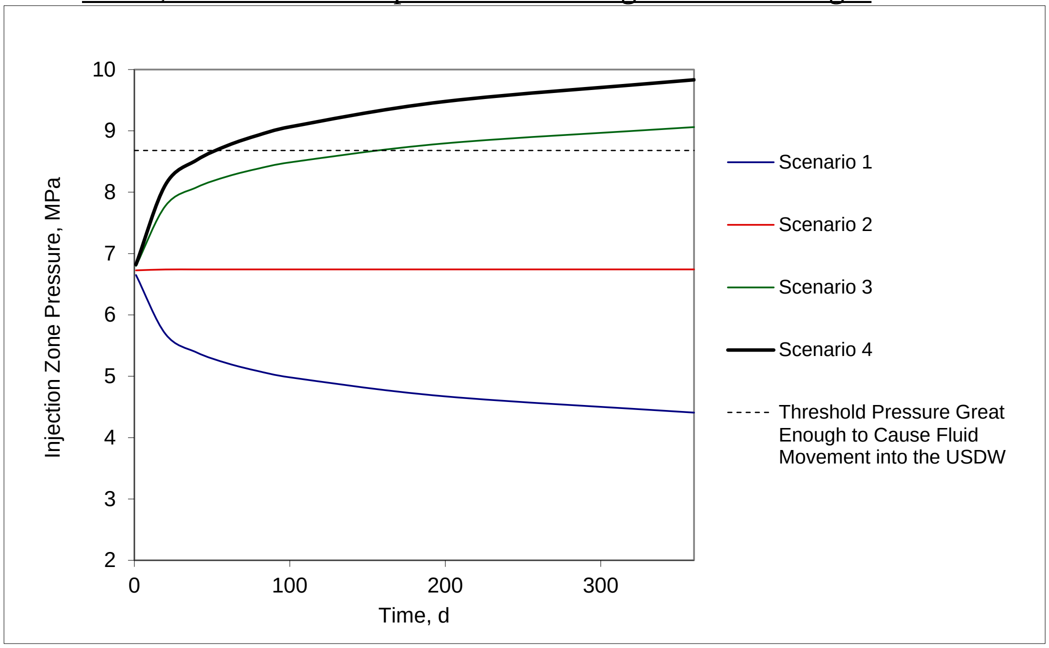


Figure 6. Predicted Change in Injection Zone Pressure with Injection and Extraction at the Abandoned Well.

Hypothetical values of pressure at the artificial penetration as a function of time for each of the four scenarios are presented in Figure 6. For Scenario 1, with production and no injection, injection zone pressure decreases, therefore decreasing risk of efflux of fluids out of the injection zone. For Scenario 2, injection and production rates are equal, and pressure in the injection zone remains nearly constant at levels only slightly above initial conditions. In Scenario 3, injection rates are greater than production rates, and injection zone pressure reaches the threshold level of 8.68 MPa at about 150 days. In Scenario 4, without any production, the threshold pressure is reached within 80 days after the start of injection. Therefore, for Scenarios 3 and 4, there is risk for efflux of native fluids into the overlying USDW, whereas for Scenarios 1 and 2 this is not the case.

Increase in Carbon Dioxide Injection Rates [40 CFR 144.19(b)(2)]

As discussed above, increased carbon dioxide injection rates may be used to increase the volume of carbon dioxide sequestered. Such an increase may indicate an increased risk to USDWs compared to Class II operations. Increased carbon dioxide injection rates are one of the key determinants of reservoir pressure and also result in an increased volume of carbon dioxide in the subsurface. Injection rates have the greatest influence on reservoir pressure in the region nearest the well bore, with decreasing influence further from the injection well.

Carbon dioxide injection rates are measured with a flow metering device (see the *UIC Program Class VI Well Testing and Monitoring Guidance*). For evaluation as a criterion, injection rates should be considered from an individual well or on a project basis by manifold monitoring. Monitoring of injection flow rates and pressures is required on at least a monthly basis for Class II ER wells [40 CFR 146.23]. Anticipated injection rates and pressures (average and daily maximum) are required information for authorization of a Class II permit [40 CFR 146.24]. Proposed injection rates and/or pressures are provided with the Class II permit application and are typically incorporated as operating conditions of the Class II permit. Any increase above those levels would be a violation of the Class II permit. When compared to historical data, injection rate increases for an extended time period may indicate increased risk to USDWs. Thresholds for the amount and duration of increase will be site-specific and based on historical operating records as well as the injection rate specified in the Class II permit. Taken in concert with other factors, injection rate increases may indicate the need for a Class VI permit.

Decrease in Reservoir Production Rates [40 CFR 144.19(b)(3)]

Owners or operators may elect to decrease reservoir production rates to maximize carbon dioxide storage. For example, produced fluids from EOR operations are typically a mixture of brine, hydrocarbons and carbon dioxide. As the efficiency of the EOR operation decreases over time, the amount of hydrocarbons in the produced fluids decreases. Production well pressure control has been described as a possible way to increase carbon dioxide storage at EOR facilities. This involves reduction of production rates when carbon dioxide levels in the produced fluid become high (Kovscek and Cakici, 2005).

Production rates may be measured with a flow metering device and may be evaluated on an individual well basis or from a manifold point for a group of production wells. Reservoir production rates are measured during ER operations, but reporting to the Class II UIC Program Director may not be required, as monitoring and reporting of reservoir pressure is not a Class II federal permit requirement. Thus, injection and production rates may be the best indicator of how reservoir pressure is changing. In cases where the Class VI UIC Program Director does not have access to reservoir production data, he/she may request these data from the Class II UIC Program Director or the owner or operator pursuant to requirements at 40 CFR 144.17.

When the sum of total fluid production (i.e., the total volume of brine, hydrocarbons and carbon dioxide produced) is less than the total fluid injection for a significant period of time, there will be increased reservoir pressure, potentially increasing the risk to USDWs (see Box 2). The amount of the pressure change will be based on several factors, as discussed above, including the change in injection and production volumes relative to the total pore volume of the storage reservoir/injection zone. If production rates decline significantly for an extended period of time (e.g., six months to one year) and reservoir injection rates are steady or increasing, this may indicate that a Class VI permit is required. Decisions regarding whether a Class VI permit is needed would be made considering the potential for decreasing production rates which leads to elevated pressure that may pose a risk to USDWs, along with other factors, including modification of operational parameters or other mitigation measures.

Distance Between Injection Zone and USDWs [40 CFR 144.19(b)(4)]

The distance between the injection zone and the lowermost USDW is a primary determinant of the risk to USDWs posed by the injection operation. Increased distance between the injection zone and lowermost USDW allows for a larger pressure increase within the injection zone before USDWs might become endangered. This is demonstrated by Equation 1 (see page 14), which shows that as the term representing the distance between the injection zone and lowermost USDW (z_u - z_i) increases, the threshold pressure, that would result in possible fluid migration into a USDW through a hypothetical open conduit ($P_{i,f}$), increases. Similarly, if fluid leakage does occur through the confining zone, greater distance between the injection zone and lowermost USDW will allow for increased trapping of mobilized fluids before reaching the USDW. A greater vertical distance also increases the likelihood that there will be additional zones between the injection zone and the lowermost USDW that are available for monitoring.

In certain circumstances, the distance between the injection zone and the lowermost USDW may be adequate for the permitted Class II ER operation, but not necessarily adequate for a proposed GS project in the same location. If pressures within the injection zone increase beyond those allowed for the Class II operation, the possibility exists for greater vertical fluid migration and increased risks to USDWs. Furthermore, increased fluid injection rates may result in lateral fluid movement to areas where the distance between the injection zone and the lowermost USDW is not known.

The locations and depths of all USDWs are required information for a Class II permit application [40 CFR 146.24]. However, Class II requirements will likely not be sufficient for a carbon dioxide operation transitioning to GS if the distance to the lowermost USDW is small, allowing for the possibility of fluid leakage into the USDW. If the owner or operator or the Class VI UIC Program Director determines, from consideration of other factors, that a Class VI permit may eventually be required for the project, the distance between the injection zone and the lowermost USDW should be considered in determining when the Class VI permit is required.

Box 2: Example of Pressure Increase with Reduction in Production Rates

Reduction of fluid production rates, with steady or increasing carbon dioxide injection rates, will result in increased fluid pressure within the injection zone. For the simple hypothetical example shown in Box 1, Scenario 2, when injection and production rates are similar for the injection and extraction wells, reservoir pressure remains approximately constant. However, if production rates for Scenario 2 were to decrease, reservoir pressures are expected to increase. The change in reservoir pressure with a decrease in production rates from 3000 m^3/d to 500 m^3/d after 360 days was evaluated. As can be seen, in the hypothetical graph of pressure increase (Figure 7), at 700 days total, or 340 days after reduction of the fluid production rate, pressure has increased above the threshold necessary for fluids to flow from the injection zone into the USDW at the abandoned well (8.68 MPa).

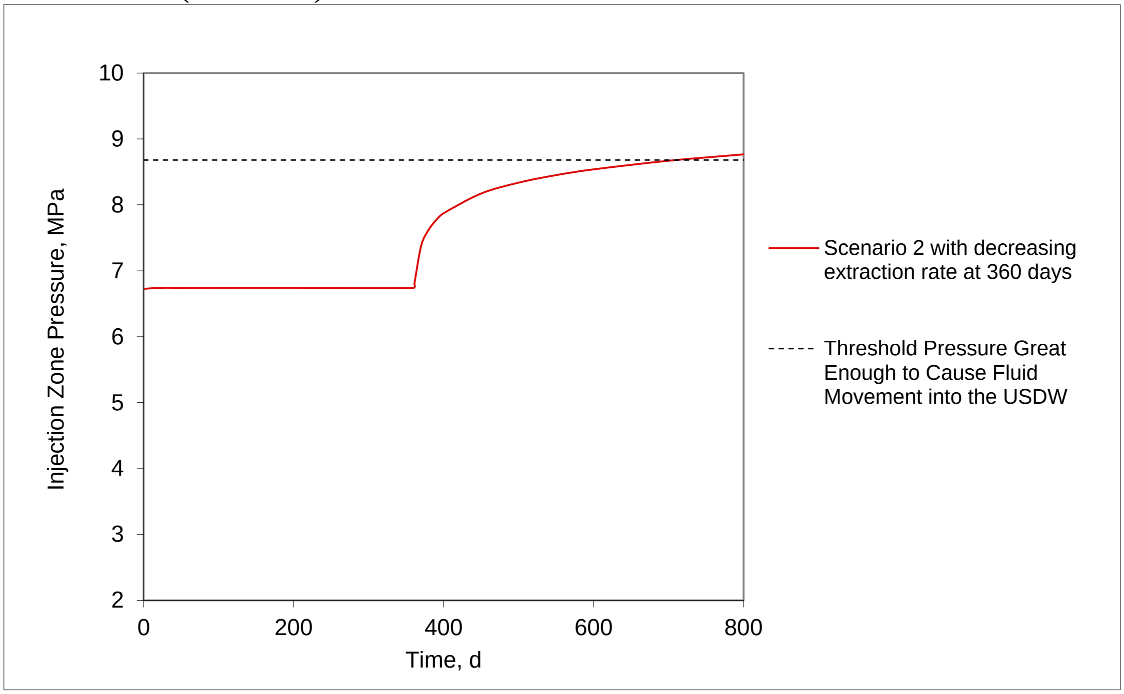


Figure 7. Graph of Predicted Change in Reservoir Pressure for Scenario 2 (see Box 1), with a Decrease in Reservoir Production Rate at 360 Days.

3.2 Suitability of Class II Area of Review Delineation [40 CFR 144.19(b)(5)]

The AoR is the area around the injection well that may be affected by injection and that must be reviewed for the presence of artificial penetrations (i.e., wells) or other conduits for fluid movement. A key difference between Class II and Class VI requirements is the process for delineating the AoR (see Appendix I). The AoR for Class II wells is defined as either a fixed radius of 1/4 mile, or by a simple radial calculation based on the Theis formula [40 CFR 146.6].

For Class VI wells, the AoR must be delineated using sophisticated computational modeling that accounts for multiphase flow of carbon dioxide and native fluids and takes into account any geologic heterogeneities, other discontinuities, data quality and their possible impact on model predictions [40 CFR 146.84]. A Class VI AoR may be much larger than that for a Class II well, and it may be non-circular. For more information regarding AoR delineation for Class VI wells, see the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance.*

For a project transitioning from ER to GS, the original Class II AoR delineation may no longer be adequate. For example, elevated pressure and/or fluid migration may occur outside of the Class II delineated AoR. This is demonstrated by the hypothetical example provided in Box 1 (on pages 21 to 23) and Box 2 (on page 26). The artificial penetration in this hypothetical example is located 1/4 mile (approximately 400 meters) from the injection well and could, therefore, be at the outermost boundary of a Class II AoR delineation. As shown in Figure 7, as operational parameters at the project change to more closely represent GS rather than ER, reservoir pressure at artificial penetrations in the AoR may increase to levels that may cause fluid movement into a USDW. In these cases, the AoR should be re-delineated to include any area that exhibits this elevated pressure. Under these circumstances, a Class VI permit may be required for continued injection well operation.

Any monitoring data that indicate the presence of carbon dioxide or the pressure front (elevated pressure great enough to cause fluid movement into the lowermost USDW) beyond the Class II AoR is evidence that the AoR does not meet the Class VI requirements. Furthermore, relatively simple analytical modeling or more sophisticated computational modeling may be needed to estimate whether the Class II AoR delineation is adequate in comparison to AoR requirements under the Class VI Rule. EOR operations routinely use sophisticated computational modeling and uncertainty analysis to plan and evaluate the project, and this modeling may be used to assess the adequacy of the current AoR delineation.

Carbon dioxide plume and pressure front monitoring and modeling data are routinely collected and analyzed at ER operations as part of typical monitoring activities to ensure proper operation of the injection well. Reporting the results of this type of monitoring, though, is not required under Class II federal permit requirements. In cases where the Class VI UIC Program Director does not have access to these data, he/she may request these data from the Class II UIC Program Director or the owner or operator pursuant to requirements at 40 CFR 144.17.

3.3 Quality of Abandoned Well Plugs [40 CFR 144.19(b)(6)]

The quality of abandoned well plugs and well construction are key determinants of the risk to USDWs posed by the injection operation. To prevent fluid movement, abandoned wells should include a cement plug through the primary confining zone and/or across the injection zone-confining zone contact. The cement plug should have sufficient integrity to contain separate-phase carbon dioxide and elevated pressures. Abandoned wells should also have been constructed with an adequate quantity of cement that is sufficiently bonded to the casing to prevent the upward migration of fluids between the casing and the borehole. In the absence of an adequate plug across the confining zone, cross-migration may occur where fluids enter a permeable zone below the lowermost USDW and then migrate upward from that zone. Class VI regulations require that abandoned wells be plugged using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream [40 CFR 146.84(d)]. This could warrant the use of enhanced plugging techniques, including possibly the use of specialty cements. For further information regarding locating and assessing abandoned well plugs, see the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance.*

In approving a Class II permit application, the Class II UIC Program Director is required to consider the status of corrective action on wells within the AoR [40 CFR 146.24], including: (1) the type and number of plugs to be used; (2) the placement of each plug including the elevation of the top and bottom; (3) the type, grade and quantity of cement to be used; and (4) the method of emplacement of the plugs. This information should, therefore, be available to the Class VI UIC Program Director and may be provided in abandoned well plugging records and/or plug field testing. If the owner or operator or the Class VI UIC Program Director determine from consideration of other factors that the project may be transitioning to GS and a Class VI permit is required, the quality of abandoned well plugs should be considered.

3.4 Anticipated Plan for Recovery of Injected Carbon Dioxide at Cessation of Injection for ER [40 CFR 144.19(b)(7)]

For current ER operations, owners or operators may attempt to recover as much carbon dioxide from the subsurface as possible for recycling and use in future projects at other sites since carbon dioxide is currently a valuable commodity and an important investment at ER projects. Recovery of carbon dioxide, to the extent possible, at the end of an ER project incidentally decreases risk to USDWs because reservoir pressure is lowered and the carbon dioxide volume left in place decreases. However, owners or operators may plug and abandon an ER project without removing any carbon dioxide under Class II requirements.

Because the objective of GS is to maximize carbon dioxide storage, owners or operators will typically leave the injected carbon dioxide in place after injection.[2] Therefore, fluid pressures in the injection zone will likely remain elevated above pre-injection levels for some period of time, and a large volume of carbon dioxide will remain in the subsurface. Separate phase carbon dioxide left in place poses a risk to USDWs because if the storage project has not been appropriately sited and operated, carbon dioxide may leak upward through leakage pathways (such as improperly abandoned wells or transmissive faults or fractures) due to buoyancy, or cause upward or downward movement of formation fluids due to elevated pressure. For example, modeling calculations indicate that accumulation of supercritical carbon dioxide at a thickness of

[2] Even if the owner or operator plans to produce some or all of the carbon dioxide eventually, a Class VI permit is required for GS projects where needed to address the potential risk to USDWs due to increased pore pressure associated with GS.

20 meters at the injection zone-confining zone interface is sufficient to cause leakage into microcracks or crevices in the confining zone as small as 2 microns in diameter (Saripalli and McGrail, 2002). Note that leakage into microcracks or crevices in the confining zone may not necessarily lead to endangerment of USDWs, as several processes may lead to attenuation of the carbon dioxide leakage above the injection zone/confining zone interface.

Owners or operators are not required to submit an anticipated plan for recovery of carbon dioxide at the end of a project to the UIC Program Director since reporting of this information is not a Class II federal permit requirement [40 CFR 146.23]. However, in cases where the Class VI UIC Program Director does not have access to this data, he/she can request these data from the Class II UIC Program Director who may obtain them pursuant to 40 CFR 146.10(c), 144.12, or 144.52(b)(1) or from the owner or operator pursuant to requirements at 40 CFR 144.17. If the anticipated plan for the end of the project changes from recovery of carbon dioxide to maximizing carbon dioxide storage, this indicates that the primary purpose of the project is GS. Given this, risks to USDWs will remain after injection ceases, and therefore, post-injection monitoring and site care should be required. For these reasons, a Class VI permit may be required.

3.5 Source and Properties of Injected Carbon Dioxide [40 CFR 144.19(b)(8)]

As previously discussed, carbon dioxide used in ER projects may be anthropogenic in origin (e.g., from a natural gas processing plant, fertilizer production plant, or coal-fired power plant) or may come from natural underground geologic sources. Currently, the majority of carbon dioxide used in ER is from natural sources. The chemical composition of the carbon dioxide injectate, including the percent of carbon dioxide, depends on the source. Fluid properties (e.g., viscosity, density and potential acidity and corrosivity when mixed with water) and concomitant risks to USDWs are influenced by the chemical composition of the injectate. For example, sulfur dioxide may be an impurity in anthropogenic carbon dioxide streams from coal-fired power plants. Several studies have suggested that sulfur dioxide in the injected carbon dioxide stream may result in lower pH in the injection zone than if pure carbon dioxide is injected (Xu et al., 2007; Knauss et al., 2005). The lower pH may mobilize drinking water contaminants (e.g., arsenic or lead). If levels of drinking water contaminants within the injectate (such as mercury or hydrogen sulfide) increase with a change in carbon dioxide source, this may pose a risk to USDWs.

The source of the injected fluid, along with an analysis of its chemical and physical characteristics, is required information that the Class II UIC Program Director considers for approval of a Class II permit application [40 CFR 146.24]. Furthermore, Class II owners or operators are required to report on the properties of the injectate at a time interval frequent enough to represent its characteristics [40 CFR 146.23]. Likewise, owners or operators must submit analyses of the carbon dioxide injectate when applying for a Class VI permit [40 CFR 146.82(a)(7)(iv)] and are required to submit analyses of the injectate at an appropriate time interval [40 CFR 146.90(a)]. Thus, these data may be considered by the Class VI UIC Program Director to inform a re-permitting decision.

3.6 Additional Factors Determined by the UIC Program Director [40 CFR 144.19(b)(9)]

The Class VI UIC Program Director may specify additional factors that are tailored to the information available to him/her based on regional or state requirements and site-specific geologic and operational conditions. Examples of additional factors include, but are not limited to:

- Migration of carbon dioxide into regions known to exhibit faults, fractures, or additional migration pathways;

- Evidence of surface leakage of carbon dioxide or constituents mobilized by the injection process; and

- Increased risk of induced geomechanical activity, including fault slippage, due to increased injection rates and pressures.

The Class VI UIC Program Director will and the Class II UIC Program Director is encouraged to evaluate the site-specific factors influencing risks to USDWs at a particular project to support appropriate permitting and inform re-permitting decisions. EPA encourages various permitting authorities to work across agencies and with owners or operators, as appropriate, to facilitate the transfer and evaluation of relevant information about a site and to ensure that all existing data are available to the Class VI permit writer.

4 UIC Requirements for Wells Transitioning from the Class II to the Class VI Program

Following a determination that there is an increased risk to USDWs from the injection project (see Section 3), owners or operators will need to apply for a Class VI permit. This section describes additional Class VI requirements that owners or operators must meet following a determination that a Class II ER project will transition to a Class VI GS project. Section 4.1 briefly describes well construction requirements for Class II ER wells. Section 4.2 presents Class VI well construction requirements and identifies considerations that may be appropriate for the conversion of Class II wells to Class VI wells. Section 4.3 describes the operating-phase requirements that owners or operators must meet under a Class VI permit. Finally, Section 4.4 discusses how owners or operators following the individual well permitting requirements for Class VI wells can achieve some of the efficiencies of area permits that are allowed under some other UIC well classes.

4.1 Class II ER Well Construction and Corrosion

Owners or operators may drill Class II carbon dioxide injection wells as new wells, but it is very common to convert existing production or water injection wells into carbon dioxide injection wells. Carbon dioxide injection wells used for ER are constructed to meet the UIC Class II requirements, with a surface casing and production casing. Casing thicknesses are selected based on injection and production pressures, well depth and reservoir properties. Casings are usually constructed with carbon steel, and in deep (greater than 10,000 feet) high-pressure, high-temperature environments; high strength grades of well casing may be used. Corrosion resistant alloys are also used when necessary (Meyer, 2007).

When carbon dioxide is mixed with water or impurities (e.g., nitrogen oxides, sulfur oxides, hydrogen sulfide), it can be corrosive to well materials and cements commonly used in well construction. Cements with a reduced Portland cement content are more resistant to corrosion caused by acids, such as carbonic acid, because they contain less calcium carbonate. Acid resistant cements can be formulated by adding fly ash, silica fume (microsilica), latex, epoxy or other substances. Limited results of field studies at EOR production fields (e.g., Carey et al., 2007) show clear evidence of reactions between carbon dioxide and well cement. However, both laboratory research (e.g., Kutchko et al., 2007, 2009) and field studies suggest that wet carbon dioxide-induced alteration of cement does not necessarily result in degradation to the point where cement strength and permeability are substantially affected (Kutchko et al., 2007; Crow et al., 2009).

4.2 Meeting the Well Construction and Logging Requirements for Class VI Wells

In recognition that some Class II ER wells may have been built to Class VI standards or their equivalent, the Class VI Rule allows, on a case by case basis, grandfathering of components of previously permitted Class II wells at the discretion of the UIC Program Director [40 CFR 146.81(c)]. Some Class II ER wells are built according to specifications appropriate for the injection of carbon dioxide for ER; in some cases, the wells may have been constructed in a manner to maintain MI when in contact with carbon dioxide for the purpose of GS. However, the UIC Program Director may determine that, based on construction specifications, the well has not been designed to maintain integrity for GS operations. For example, GS operations may employ greater injection pressures than ER operations.

The Class VI Rule describes the requirements for owners or operators seeking to re-permit existing Class II wells to Class VI wells for the purpose of GS at 40 CFR 146.81(c). Owners or operators planning to convert existing Class II wells to Class VI wells must, per 40 CFR 146.81(c), demonstrate to the Class VI UIC Program Director that the wells were engineered and constructed to meet the requirements at 40 CFR 146.86(a). The owner or operator must also demonstrate that the wells will ensure protection of USDWs in lieu of the requirements for casing and cementing of Class VI wells at 40 CFR 146.86(b) and the requirements for logging, sampling and testing prior to injection well operation at 40 CFR 146.87(a). For further information on well construction to meet these Class VI requirements, see the *UIC Program Class VI Well Construction Guidance.* If an owner or operator seeking to grandfather an existing Class II well to a Class VI well cannot make this demonstration, then re-permitting of the constructed well will not be allowed. The owner or operator may discuss with the Class VI UIC Program Director whether remedial activities will enable the well to meet Class VI requirements or if construction of a new Class VI well or selection of an alternative well for conversion is needed.

It is important to note that although the Class VI Rule provides for “grandfathering” the construction of Class II wells, Class II owners or operators transitioning to Class VI wells will need to apply for and obtain a Class VI permit in order to continue safe, appropriately permitted carbon dioxide injection [40 CFR 146.82(a)]. The sections below (4.2.1 and 4.2.2) focus on the requirements from 40 CFR 146.86 through 146.87, differentiating between the requirements that must be met by owners or operators of transitioning wells (40 CFR 146.86(a) and (c) and 40 CFR 146.87(b) through (f)) and recommendations for consideration when transitioning (related to 40 CFR 146.86(b) and 146.87(a)). For additional information on the Class VI requirements, see the *UIC Program Class VI Well Site Characterization Guidance,* the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance;* and the *UIC Program Class VI Well Construction Guidance.*

4.2.1 Construction and Logging Requirements and Considerations for Wells Transitioning from Class II to Class VI

Owners or operators seeking to transition their wells from Class II to Class VI do not necessarily have to meet all the requirements for construction and logging as required at 40 CFR 146.86 and 146.87. Instead, they are required to meet a performance standard, demonstrating a well is adequately constructed to prevent endangerment of USDWs in lieu of specific requirements for well casing, cementing and logging. Only well construction can be "grandfathered;" owners or operators of wells transitioning from Class II to Class VI must meet all other requirements of the Class VI Rule.

The following list briefly describes the Class VI requirements and how they apply to wells transitioning from Class II to Class VI or may be considered in re-permitting determinations:

> CLASS VI WELL EQUIPMENT
>
> Caliper Tools – Used for casing inspection.
>
> Sonic Logging Tools – Used for cement testing.
>
> Temperature and Pressure Sensors – Used for mechanical integrity tests and formation monitoring.
>
> Seismic Imagers – Used for tracking the carbon dioxide plume.
>
> Bridge Plugs or Portable Packers – Used to seal off portions of the well for pressure tests or repair work.
>
> Radioactive Tracer Tools – Used for mechanical integrity tests.
>
> Noise Logging Tools – Used for mechanical integrity tests.
>
> Down-hole Fluid Samplers – Used for geochemical sampling.
>
> Electromagnetic Survey Logger – Used for casing inspection.
>
> Down-hole Cameras – Used for inspection of the well.
>
> Ultrasonic Imaging Tools – Used for casing and cement inspection.
>
> Gravimeters – Used for plume tracking.
>
> Down-hole Safety Valves – Used to replace failed tubing deployed valves or to temporarily seal off the well.

- Requirement: Class VI wells must be constructed to prevent fluid movement into or between USDWs or any other unauthorized zones (e.g., no fluid movement outside the injection zone) [40 CFR 146.86(a)(1)]. This is the central construction requirement for Class VI wells and is the performance standard all wells transitioning to Class VI must meet. Class II wells that cannot meet this requirement cannot be re-permitted as Class VI wells.

- Requirement: Class VI wells must be constructed to allow all appropriate workover and testing equipment [40 CFR 146.86(a)(2)] and to allow monitoring of the annulus between the long string casing and the injection tubing [40 CFR 146.86(a)(3)]. The box to the right presents examples of equipment that may need to be used to satisfy Class VI requirements. All wells transitioning to Class VI must meet these requirements [40 CFR 146.86(a)].

- Requirement: Class VI wells must inject through tubing and a packer [40 CFR 146.86(c)(2)] that are designed to be compatible with fluids they will contact or exceed standards developed for such materials such as those developed by the American Petroleum Institute (API) or American Society for Testing and Materials (ASTM) [40 CFR 146.86(c)(1)]. Wells transitioning to Class VI must meet this requirement.

- Requirement: Class VI owners or operators must submit a report on whole or sidewall cores [40 CFR 146.87(b)]; record fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone(s) [40 CFR 146.87(c)]; calculate the fracture pressure and other physical and chemical characteristics of the confining zone and injection zone [40 CFR 146.87(d)]; and conduct a pressure fall-off test; and a pump test or an injectivity test [40 CFR 146.87(e)]. All Class VI wells including those transitioning from Class II must meet this requirement, and previously conducted monitoring tests, while informative for historical comparison, may not be sufficient to satisfy Class VI permitting requirements. The owner or operator and the Class VI UIC Program Director should discuss the need for updating any of these tests as part of the discussions related to the Class VI permit application.

- Consideration: Class II wells transitioning to Class VI that have casing and cement that are appropriate for carbon dioxide injection and that will prevent endangerment of USDWs may be grandfathered. When assessing this, the Class VI UIC Program Directors may give consideration to: whether the wells have casing and cement that are compatible with the fluids and materials with which they will come into contact and are designed for the life of the well [similar to the requirements for new wells at 40 CFR 146.86(b)(1) and (5)]; the depth of the surface casing and how it is cemented to ensure protection of USDWs [as in 40 CFR 146.86(b)(2)]; and the depth of the long string casing and how it is cemented to ensure protection of USDWs [similar to 40 CFR 146.86(b)(3)].

- Consideration: Permit applicants for newly proposed but not yet constructed Class VI wells must perform comprehensive logging and testing to verify well construction and demonstrate MI of the well. Such logs and tests include: deviation checks on all wells constructed by enlarging a hole [40 CFR 146.87(a)(1)]; resistivity, spontaneous potential, caliper and cement bond logs before the well's surface casing is completed [40 CFR 146.87(a)(2)]; and resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder log, cement bond and variable density log, and a temperature log before and upon completion of the well's long string casing [40 CFR 146.87(a)(3)]. Class VI owners or operators must also perform both internal and external MITs [40 CFR 146.87(a)(4)].

  In lieu of the owner or operator of a well that is applying to transition from Class II to Class VI performing the tests outlined at 40 CFR 146.87(a) for the purpose of re-permitting, EPA anticipates that the Class VI UIC Program Director may evaluate previous logs and tests run on the (Class II) well to determine that the well was constructed to achieve the goals of 40 CFR 146.86(a), has sufficient integrity to prevent fluid movement and that the formation is adequate to accept and contain carbon dioxide at the rate and volume anticipated to be injected at the GS project. If such information is not available to inform the Class VI UIC Program Director's decision, it is within his or her authority to request additional information to inform a final decision on whether re-permitting is appropriate.

4.2.2 Considerations for Demonstrating that Transitioning from a Class II to a Class VI Injection Well is Appropriate

To successfully re-permit a Class II well as a Class VI well, the key requirement regarding construction is to demonstrate to the Class VI UIC Program Director that the well, as constructed and completed, will prevent fluid movement into or between USDWs or into any unauthorized zones pursuant to requirements at 40 CFR 146.86(a)(1) under the conditions anticipated for GS.

Specifically, an owner or operator will need to demonstrate that the well materials and cements will be able to withstand the down-hole operating conditions that are anticipated following transition to GS without developing leaks. Considerations for this demonstration include the potentially corrosive nature the carbon dioxide stream, formation fluids, or carbon dioxide-brine mixtures. Additionally, injection pressures may be higher for a GS project than for an ER project, and the owner or operator will need to demonstrate that the materials have adequate strength to withstand these elevated pressures. If the Class II well was constructed for injection of carbon dioxide for ER purposes, it may be sufficient to demonstrate to the Class VI UIC Program Director that such suitable materials were used and that these materials have not degraded as a result of past operations.

This will likely involve an ongoing discussion between the owner or operator and the Class VI UIC Program Director throughout the re-permitting process regarding applicable requirements. This section discusses requirements and considerations related to injection wells; for information pertaining to the construction of monitoring wells, see the *UIC Program Class VI Well Testing and Monitoring Guidance.*

The sections below present considerations that may aid an owner or operator in demonstrating to a Class VI UIC Program Director that a well is adequately constructed to prevent fluid movement. Essentially, in order to demonstrate that the construction is adequate, the owner or operator must demonstrate that the well has both internal and external MI and will be able to maintain MI throughout the life of the project to meet the requirements of 40 CFR 146.81(c).

Materials Strength

The owner or operator and the Class VI UIC Program Director will need to consider well material strength when evaluating the information submitted in compliance with requirements at 40 CFR 146.86(c)(3). Additionally, the Class VI UIC Program Director, in confirming that the well is appropriately engineered and constructed to meet the requirements of 40 CFR 146.81(c), will likely also consider the cement and casing material strength.

The owner or operator can demonstrate adequate materials strength by providing computations showing calculated down-hole stresses on the casing, tubing, cement and packer. These calculated values can be compared with strength values for the materials in place. The strength of the materials used in the well construction will most likely have been submitted with the original

Class II permit application; although, the current condition of the well materials will be a more relevant consideration. A current pressure test at a pressure equal to or higher than the proposed injection pressure may help demonstrate sufficient material strength. If the records are missing from the original permit files, the Class VI UIC Program Director may request that they be resubmitted.

The owner or operator can demonstrate that the well materials can maintain MI and are compatible with the carbon dioxide stream through direct testing of the materials with the proposed carbon dioxide stream or through detailed materials compatibility assessments using published literature showing that the materials will not corrode significantly in the presence of the carbon dioxide stream or carbon dioxide-rich brine. The *UIC Program Class VI Well Construction Guidance* has additional information and resources for determining the stress on well components.

Casing

While an owner or operator of a Class II well applying to transition to a Class VI well need not comply with the requirements at 40 CFR 146.86(b) as per 40 CFR 146.81(c), EPA encourages owners or operators to consider—and anticipates that Class VI UIC Program Directors will carefully evaluate—the placement of casing and materials of a well proposed for conversion. Such an assessment may include evaluating whether the casing is intact and the zones through which it is completed. When an owner or operator is selecting a Class II well for re-permitting as a Class VI well, the owner or operator may consider selecting a well where the long string casing extends to the top of the injection zone as such a well design provides optimal protection across multiple subsurface formations. Construction plans for the well (whether from the original Class II well permit application or more recent plans) showing the current design of the well may be referenced to provide the details of casing placement and demonstrate that the well is constructed to meet the requirements of 40 CFR 146.86(a). The casing diameter must be sufficiently large to permit any testing or logging equipment required by the Testing and Monitoring Plan and any workover equipment that might be anticipated [40 CFR 146.86(a)(2)]. The owner or operator will need to demonstrate that the casing has not corroded or been damaged to the extent that it cannot meet the requirements at 40 CFR 146.86 or can no longer maintain MI. Such a demonstration may be achieved by MITs and/or wireline logs and is discussed in more detail in the section on logging and testing below.

Cement

Cement is essential for providing external MI by helping to prevent fluid migration along the well bore annulus. Part of the owner or operator's demonstration that a well being considered for conversion to Class VI is constructed and completed to meet the requirements at 40 CFR 146.86(a) includes an assessment of the appropriateness of the cement placement, type, compatibility and integrity.

While newly constructed Class VI wells must be cemented to the surface [40 CFR 146.86(b)], there is some flexibility afforded owners or operators applying to re-permit existing Class II wells as Class VI wells. Specifically, wells re-permitted to Class VI may not need to meet the requirement that their long string casing be cemented to the surface. Under such circumstances, EPA anticipates that the Class VI UIC Program Director would require the owner or operator to demonstrate that there is proper zonal isolation. In all cases, however, re-permitting is contingent upon a demonstration that the well meets the requirements at 40 CFR 146.86(a) to prevent the movement of fluids into or between USDWs or into any unauthorized zones. Cement logs can be used to show placement of the cement with respect to USDWs and other permeable formations and cement logs complemented by other MI logs can identify the position and integrity of well cement.

The UIC Program Director may evaluate whether a well has cement in the following locations: from the injection zone up through and to some distance above the base of the confining layer (some states require 500 feet for Class II wells); through any overpressured zones (zones that are overpressured relative to the normal geologic pressure gradient); and through any USDW. When identifying and selecting a well for transitioning to Class VI, the owner or operator may also consider whether the well was cemented through any active oil or gas formations and between permeable formations where pressure differences could cause fluid movement. Cementing in these zones is consistent with industry best operating practices.

The owner or operator should also provide information to the Class VI UIC Program Director to inform his or her assessment of the proposed well's integrity. External MITs and logs (as discussed in the logging and testing section) can indicate cement integrity. If external MITs indicate channels or microannuli in the cement (i.e., flow behind pipe), an owner or operator may be able to repair them using cement squeezes. The *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* includes details relevant to repairing faulty cement. (Note that, although well condition and remediation discussions in that guidance focus on abandoned wells, they are applicable to re-permitted wells.)

Tubing and Packer

Injection must occur through tubing and a packer to prevent migration of carbon dioxide up the annulus between the tubing and casing [40 CFR 146.86(c)(2)]. The tubing and packer should meet the material requirements discussed above and should be pressure tested prior to operation to the maximum injection pressures expected during the lifetime of the GS project. If the existing tubing and packer are missing or inadequate, they would need to be replaced. The tubing must also be installed in such a way that the annulus between the tubing and casing can be monitored [40 CFR 146.86(a)(3)]. The *UIC Program Class VI Well Testing and Monitoring Guidance* provides more details on how to monitor the annular space between the tubing and casing.

Logging, Sampling and Testing

For owners or operators applying to convert a Class II well to Class VI, the logging, sampling and testing requirements at 40 CFR 146.87(a) are not required, per 40 CFR 146.81(c), provided the owner or operator demonstrates to the Class VI UIC Program Director's satisfaction that the well is engineered and constructed to meet the requirements at 40 CFR 146.86(a). However, an owner or operator must meet the requirements of 40 CFR 146.87(b) through (f). The purpose of the suite of requirements at 40 CFR 146.87 is to ensure that sufficient information regarding both the well and (geologic) formations the well intersects is available to the Class VI UIC Program Director to enable him/her to establish operational conditions, confirm USDW protection and authorize injection.

To ensure that such information is available to inform a Class VI UIC Program Director's evaluation of a well for re-permitting, EPA recommends that the owner or operator conduct and submit the results of internal and external MITs. However, the owner or operator and the UIC Program Director should discuss what logs and tests may need to be performed to ensure that the transitioned well was engineered and constructed to meet the requirements at 40 CFR 146.86(a).

- Tests or logs to demonstrate internal MI – Although specific tests are not required for wells transitioning from Class II to Class VI, the owner or operator must demonstrate to the UIC Program Director that the well is designed to prevent fluid movement into USDWs in order to meet the requirements of 40 CFR 146.81(c). If recent mechanical integrity test results are available for a transitioning well, the Class VI UIC Program Director may choose to review them as evidence that the well has internal MI. Otherwise, the owner or operator may consider performing a caliper log, casing inspection log, or video log in order to demonstrate that the casing is intact. Options for demonstrating internal MI can include standard annulus pressure tests, ultrasonic imaging logs and tracer surveys.

- Tests or logs demonstrating external MI – As with internal MITs, specific external MI tests are not required for wells transitioning from Class II to Class VI, but the owner or operator must demonstrate to the UIC Program Director that the well is designed to prevent fluid movement into USDWs in order to meet the requirements of 40 CFR 146.81(c). If recent mechanical integrity test results are available for a transitioning well the Class VI UIC Program Director may choose to review them as evidence that the well has external MI. Temperature logs, oxygen activation logs and noise logs may aid in identifying any channeling in the cement. If channels or microannuli are detected through logging, drilling out the well and recementing may be necessary. Alternatively the UIC Program Director may determine that the well is not suitable for re-permitting.

- Other logging and testing activities – An owner or operator applying to repermit a well as a Class VI well must comply with all requirements at 40 CFR 146.87(b) through (f). Information on complying with these requirements and discussions on the advantages and considerations for various logs and test can be found in the *UIC Program Class VI Well Testing and Monitoring Guidance.* Additionally, it should be noted that, in the event that an owner or operator conducts any logging or testing requested by the Class VI UIC Program Director to support re-permitting of a well, the owner or operator must provide the Class VI UIC Program Director with the opportunity to witness any such logging and testing [40 CFR 146.87(f)].

4.3 Non-Construction Related Permit Requirements

Following transition to Class VI, owners or operators will need to meet the requirements in the Class VI Rule throughout the lifetime of the GS project. While some required activities may have been included in a Class II permit, others are unique or more specific. The following sections describe the requirements that owners or operators must meet under a Class VI permit and how they may differ from the requirements of a Class II permit. See Appendix I for a detailed comparison of the Class II and Class VI requirements.

4.3.1 Injection Well Operation

Owners or operators of Class VI wells must comply with injection well operating requirements that are more comprehensive than those required under Class II permits. The Class VI Rule contains requirements at 40 CFR 146.88 for injection pressure limitations, use of automatic shut-off systems and annulus pressure requirements. These requirements are intended to ensure that injection of carbon dioxide does not endanger USDWs. Down-hole shutoff devices are required for offshore wells and may be required for onshore wells at the discretion of the Class VI UIC Program Director [40 CFR 146.88(e)(2)].

While all owners or operators must limit injection pressure such that injection may not initiate new fractures or propagate existing fractures, Class VI well owners or operators must meet the requirement that the injection pressure does not exceed 90 percent of the fracture pressure of the injection zone, except during stimulation [40 CFR 146.88(a)]. Because Class II permits might not contain conditions that reflect this requirement, owners or operators will need to be aware of this Class VI requirement and ensure that information needed to calculate fracture pressure and an appropriate injection pressure is incorporated into the Class VI permit application. It may be necessary to adjust injection operations accordingly following transition.

Class II well owners or operators are not universally required to install continuous recording devices, alarms and automatic shut-off systems or other safety devices (although such practices may be considered best practices to ensure mitigation of any potential well component or operational problems). The Class VI Rule requires the installation and use of alarms and automatic surface shut-off systems for onshore injection wells and, at the discretion of the Class VI UIC Program Director, down-hole shut off systems may also be required [40 CFR 146.88(e)(2)]. For offshore Class VI injection wells located within state territorial waters, alarms and automatic down-hole shut-off systems are required [40 CFR 146.88(e)(3)]. Although surface shut-off systems are not required for offshore wells, EPA recommends they be installed in addition to the required down-hole systems. Surface safety valves can be beneficial to protect against failures above the downhole valve and to provide a second barrier against loss of well control.

The owner or operator should provide information about what devices, if any, were previously installed on the well. Because the Class II well may be constructed without these devices, the Class VI UIC Program Director should consider whether the addition of these devices will interfere with well testing and monitoring required at 40 CFR 146.86(a)(2) and (3). If appropriate retrofits to install the required equipment cannot be made or if they would interfere with operation of the well in a manner required under the Class VI regulations, then transition to a Class VI well is not an option.

Owners or operators of Class VI wells are subject to more specific requirements regarding maintaining a pressure on the annulus that exceeds the operating injection pressure [40 CFR 146.88(c)] and maintaining MI of the well [40 CFR 146.88(d)]. Similarly, Class VI well owners or operators are subject to specific procedures at 40 CFR 146.88(f)(1-5) if a loss of MI is discovered or a shutdown (i.e., down-hole or at the surface) is triggered. While similar requirements may have been included as conditions of a Class II permit, owners or operators will need to be aware of these more comprehensive Class VI requirements and ensure that they are met.

For more information on injection well operation, refer to the *UIC Program Class VI Implementation Manual for State Directors* as well as the *UIC Program Class VI Well Construction Guidance*.

4.3.2 Mechanical Integrity

The primary differences in the MI testing requirements for Class VI owners or operators relative to those for Class II well owners or operators are the need to continuously monitor to demonstrate internal MI and the increased frequency of external MITs for Class VI compared to Class II.

Following transition to Class VI, owners or operators must continuously monitor injection pressure, flow rate and injected volumes, as well as the annular pressure and fluid volume to demonstrate internal MI of their injection wells [40 CFR 146.89(b)]. Although the Class II injection wells may have been equipped to monitor these parameters, owners or operators transitioning to Class VI should ensure that the equipment is appropriate for collecting data in the appropriate format for supporting the required reporting of these data in compliance with the Class VI regulations.

Following transition to Class VI, owners or operators must demonstrate external MI of their injection wells at least annually; this will likely be an increase from the Class II permit conditions, as the federal Class II regulations require either a demonstration of external MI at least once every five years [40 CFR 146.23(b)(3)] or documentation of cementing records [40 CFR 146.8(c)(2)]. Owners or operators of Class VI wells also must demonstrate external MI using a tracer survey or a temperature or noise log [40 CFR 146.89(c)(2)]. Following transition to Class VI, owners or operators would no longer be able to submit cementing records to demonstrate the presence of adequate cement to prevent significant fluid movement into a USDW through vertical channels adjacent to the well bore in lieu of conducting external MITs, as the Class II regulations allow at 40 CFR 146.8(c)(2).

Owners or operators applying for a Class VI permit must run a casing inspection log if required by the UIC Program Director, as specified at 40 CFR 146.89(d). Owners or operators of Class II wells should be prepared for this additional possible requirement because both the Class II and

Class VI regulations allow for flexibility regarding MITs, at the UIC Program Director's discretion [40 CFR 146.8(d); 40 CFR 146.89(g)]. The Class VI UIC Program Director may require any other test to evaluate MI. Tests other than those listed in the Class VI Rule may be used if allowed by the Class VI UIC Program Director and upon written approval of the Administrator.

For more information on MI, refer to the *UIC Program Class VI Implementation Manual for State Directors*, *UIC Program Class VI Well Construction Guidance* and the *UIC Program Class VI Well Testing and Monitoring Guidance*.

4.3.3 Testing and Monitoring

Owners or operators of Class VI wells must develop and implement a comprehensive Testing and Monitoring Plan for their projects that includes injectate monitoring, corrosion monitoring, MIT of the well, pressure fall-off testing, ground water quality monitoring, carbon dioxide plume and pressure front tracking and, at the Class VI UIC Program Director's discretion, surface air and soil gas monitoring [40 CFR 146.90(h)]. The Testing and Monitoring Plan must also include a quality assurance and surveillance plan for all testing and monitoring that is performed [40 CFR 146.90(k)].

Some Class VI testing and monitoring requirements are unique (e.g., plume tracking), and others must be performed at different frequencies than may have been required in the Class II permit. Therefore, owners or operators must be aware of these new requirements and ensure that all of the required information is included in the Testing and Monitoring Plan submitted with the Class VI permit application, per 40 CFR 146.82(a)(15).

One of the most significant differences in the monitoring requirements is that Class VI well owners or operators must track the extent of the carbon dioxide plume and pressure front [40 CFR 146.90(g)]. For former (Class II) ER projects, the separate-phase carbon dioxide plume may include carbon dioxide already present in the injection zone due to previous Class II injection activities. The Class VI owner or operator must use direct methods to monitor for pressure changes in the injection zone [40 CFR 146.90(g)(1)]. Additionally, indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools) are required to track the separate phase carbon dioxide plume unless the Class VI UIC Program Director determines, based on site-specific geology, that such methods are not appropriate or feasible [40 CFR 146.90(g)(2)]. In general, the geologic scenarios where ER operations occur, i.e., porous rock layers overlain by impermeable formations, domes and structural or stratigraphic traps, are amenable to seismic and other geophysical methods. Owners or operators are likely to have conducted such surveys of the reservoir and area previously; this information may inform development of this aspect of the testing and monitoring regime. It should be noted, however, that older 2D seismic data may not be useful as a baseline for plume tracking if there is inadequate resolution or if the data collection were not suitable for detection of carbon dioxide.

Following transition to Class VI, owners or operators must periodically monitor ground water quality and geochemical changes above the confining zone(s), as specified at 40 CFR 146.90(d).

The number, placement and depth of monitoring wells will be site-specific and based on information collected during baseline site characterization. The owner or operator of a Class VI well may also be required to conduct surface air and/or soil gas monitoring at the Class VI UIC Program Director's discretion [40 CFR 146.90(h)].

Much of the remaining required testing and monitoring activities may have been included as a condition of the Class II permit. However, owners or operators may need to conduct these activities at different frequencies following transition to Class VI. For example:

- Continuous monitoring is required for injection pressure, rate and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added [40 CFR 146.90(b)] and annual external MITs [40 CFR 146.90(e)]. See the discussion of MITs for additional considerations;

- Quarterly corrosion monitoring of the well is required at 40 CFR 146.90(c);

- A casing inspection log, if required by the Class VI UIC Program Director, may be conducted at a frequency established in the Testing and Monitoring Plan pursuant to requirements at 40 CFR 146.89(d); and

- A pressure fall-off test at least once every five years, as specified at 40 CFR 146.90(f).

The owner or operator must review the Testing and Monitoring Plan at least once every five years to incorporate operational and monitoring data and the most recent AoR reevaluation [40 CFR 146.90(j)]. After this review, the owner or operator must submit a demonstration to the Class VI UIC Program Director that no amendment is needed. Otherwise, he or she must submit an amended Testing and Monitoring Plan to be approved by the Class VI UIC Program Director and incorporated into the permit. Amended plans or demonstrations must be submitted to the Class VI UIC Program Director within one year of an AoR reevaluation, following significant changes to the facility, or when required by the Class VI UIC Program Director.

For more information on testing and monitoring, refer to the *UIC Program Class VI Well Testing and Monitoring Guidance*.

4.3.4 Reporting

The reporting requirements at Class VI wells are more comprehensive and detailed than the annual reports that are typically required for Class II wells. Following transition to Class VI, owners or operators must submit project monitoring and operational data at varying intervals, including:

- Semi-annual reports of operating data and certain monitoring data [40 CFR 146.91(a)];

- The results of MITs, any other injection well testing required by the Class VI UIC Program Director, and any well workovers within 30 days [40 CFR 146.91(b)];

- Notification within 24 hours of obtaining any evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, any noncompliance with a permit condition, any event that may endanger USDWs, or any release of carbon dioxide to the atmosphere or biosphere detected through any required surface air and/or soil gas monitoring [40 CFR 146.91(c)]; and

Notification 30 days prior to any planned well workover, stimulation, or test of the injection well [40 CFR 146.91(d)].The most significant change in reporting following the transition to Class VI is that owners or operators will need to report to EPA electronically, as required at 40 CFR 146.91(e). For additional information about reporting, see the *UIC Program Class VI Implementation Manual for State Directors* as well as the *UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators*.

Owners or operators of Class VI wells must retain most operational monitoring data for 10 years after the data are collected and must retain data on the carbon dioxide stream until 10 years after site closure, as required under 40 CFR 146.91(f).

4.3.5 Injection Well Plugging

In general, the requirements associated with plugging all UIC injection wells are similar. However, owners or operators of Class VI wells are subject to more specific requirements at 40 CFR 146.92 following transition (from Class II to Class VI). These requirements are to ensure that the cement and materials used to plug the injection well are compatible with the potentially corrosive fluids that result when carbon dioxide mixes with water. The purpose of such requirements is to prevent well plugging materials from degrading over time and to help prevent the movement of fluids into or between USDWs. Owners or operators of Class VI wells are afforded flexibility in selecting plugging materials and methods, provided that the materials are suitable for contact with carbon dioxide and carbon dioxide-rich fluids; owners or operators must describe these in the Injection Well Plugging Plan [40 CFR 146.92(b)].

Owners or operators of Class VI wells must develop, gain approval of, and follow an Injection Well Plugging Plan [40 CFR 146.92(b)]. Although it is likely that Class II an Class VI permits include similar requirements for plugging the injection well, the Class VI Rule contains specific requirements at 40 CFR 146.92. Specifically, owners or operators must flush the well with a buffer fluid, determine bottomhole reservoir pressure, perform a final external MIT and plug the well using plugs and cements that are compatible with carbon dioxide and the geochemistry of down-hole fluids in the formation.

Owners or operators of Class VI wells must submit a notice of intent to plug at least 60 days prior to plugging the well [40 CFR 146.92(c)]. At this time, owners or operators of Class VI wells must update the Well Plugging Plan if needed. Following plugging, owners or operators must submit a plugging report within 60 days, as specified at 40 CFR 146.92(d).

For more information on injection well plugging, refer to the *UIC Program Class VI Implementation Manual for State Directors* and the *UIC Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure*.

4.3.6 Post-Injection Site Care and Site Closure

The Class VI Rule at 40 CFR 146.93 incorporates an extended PISC, which is unique in the UIC Program and not required of other injection well classes. Class VI well owners or operators must prepare, gain approval of, and follow a comprehensive PISC and Site Closure Plan [40 CFR 146.93(a)].

Class VI well owners or operators must perform monitoring and site care following cessation of injection to show the position of the separate-phase carbon dioxide plume and the associated area of elevated pressure [40 CFR 146.93(b)]. This site care, which includes monitoring of ground water quality and the position of the carbon dioxide plume and pressure front, must continue for a timeframe established in the permit (i.e., the 50-year default or an alternative timeframe established by modeling) or until the owner or operator can demonstrate to the UIC Program Director, based on site monitoring data, that the project no longer poses a risk of endangerment to USDWs.

The owner or operator of a Class VI well must notify the Class VI UIC Program Director in writing at least 120 days prior to site closure and cessation of PISC activities, as specified at 40 CFR 146.93(d). Any changes to the PISC and Site Closure Plan that have not been previously submitted must be submitted at this time. Following the Class VI UIC Program Director's authorization of site closure, the owner or operator must plug all monitoring wells, as specified at 40 CFR 146.93(e), submit a site closure report within 90 days, as specified at 40 CFR 146.93(f), and record a notation on the deed to the facility property or any other document that is normally examined during title search, as specified at 40 CFR 146.93(g).

For more information on PISC and site closure, refer to the *UIC Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure*.

4.3.7 Emergency and Remedial Response

Requirements for emergency and remedial response are unique for owners or operators of Class VI wells. Class VI well owners or operators must develop, gain approval of, and follow a comprehensive Emergency and Remedial Response Plan that describes actions to be taken to address events that may cause endangerment to a USDW during the construction, operation and PISC periods of a GS project, as required by 40 CFR 146.94.

Owners or operators of Class VI wells are provided flexibility to design a site-specific plan that meets the requirements of 40 CFR 146.94(a). If an owner or operator obtains evidence of endangerment to a USDW, he or she must: (1) immediately cease injection; (2) take steps to identify and characterize any release; (3) notify the Class VI UIC Program Director within 24 hours; and (4) implement the approved Emergency and Remedial Response Plan [40 CFR 146.94(b)]. Class VI owners or operators must also update the Emergency and Remedial Response Plan if needed following every AoR reevaluation or other significant change to the project (a minimum of at least once every 5 years) [40 CFR 146.94(d)].

Details on how to prepare an Emergency and Remedial Response Plan are included in Section 6 of the *UIC Program Class VI Well Project Plan Development Guidance*.

4.4 Area Permits

Class II wells may be permitted on a field-basis through the use of an area permit. The use of area permits, however, is not an option for the permitting of Class VI wells, and owners or operators of Class II wells that are seeking to obtain Class VI permits must seek an individual permit for each well [40 CFR 144.33(a)(5)].

Permitting Class VI wells on an individual basis will help to more closely ensure that every well is constructed, operated, monitored, plugged and closed in a manner that is protective of USDWs and that the review is at an appropriate level of detail. Importantly, requiring separate permits for each well will ensure that the public has an opportunity to provide input on each well in the field as it is constructed or brought online. For example, while permitting authorities may be able to seek comment on several wells in an area at once, soliciting comment/input on each well will ensure that the public is aware of the number of wells in the area and has an opportunity to comment on each.

Owners or operators of Class II wells that were permitted under area permits before transitioning to Class VI may achieve efficiencies by considering the common elements and information about each well as they transition to operating under a Class VI permit. Considering all wells in a field will ensure that the site is evaluated and operated in a holistic manner and that all aspects of the project that may impact USDWs have been evaluated. For example:

- Class VI well owners or operators can perform a single modeling exercise to accomplish the AoR delineations and AoR reevaluations for several wells to meet the requirements of 40 CFR 146.84. The computational AoR modeling should account for all anticipated injection and resultant pressure changes caused by each well in a depleting/former oil and gas field, including any wells that the owner or operator anticipates bringing online in the future;

- While each well in a GS project will be subject to MITs and corrosion monitoring (per 40 CFR 146.89 and 40 CFR 146.90), owners or operators may work with the permitting authority to align testing schedules in the permits for each well so that the owner or operator can arrange to have equipment and contractors on site for all required testing at the same time;

- Some required testing and monitoring may be performed to satisfy the conditions of several permits at once. For example, owners or operators may wish to conduct ground water monitoring or carbon dioxide plume and pressure front tracking over an area that would satisfy the testing and monitoring requirements for several Class VI permits and that would meet the requirements of 40 CFR 146.90(d) and (g). This approach should be described in the Testing and Monitoring Plan, approved by the Class VI UIC Program Director, and included in each permit;

- Owners or operators will need to report the results of all required testing and monitoring for each well individually, as required at 40 CFR 146.91 (even if this means submitting multiple copies of the same report). However, EPA expects that electronic reporting will mitigate the burden associated with any duplication. For additional information about reporting, see the *UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators*;

- If several wells in a field have similar construction, owners or operators may plan to plug each well in a similar manner; however, a separate Injection Well Plugging Plan is required for each well (i.e., tailored to its depth), as required at 40 CFR 146.93. The plan must be a condition of each injection well's permit; and

- As with operational-phase testing and monitoring, as owners or operators cease injection, they may consider implementing a post-injection ground water monitoring or separate-phase carbon dioxide plume and pressure front tracking regime that satisfies the PISC and Site Closure Plans of several permits simultaneously and meets the requirements of 40 CFR 146.94.

The owner or operator should discuss the commonalities among all wells in a field and the implications of combining common elements and activities associated with multiple wells/permits with the Class VI UIC Program Director, while ensuring that every well is constructed, operated, monitored, plugged and closed in a manner that is protective of USDWs.

5 Transitioning Wells and Aquifer Exemptions

The UIC Program regulations include criteria at 40 CFR 146.4 that allow for exemption of aquifers from SDWA protection under specific circumstances. To be exempted, an aquifer cannot currently serve as a source of drinking water [40 CFR 146.4(a)] and will not serve as a source of drinking water due to any of the factors specified at 40 CFR 146.4(b), e.g., that it is mineral, hydrocarbon or geothermal energy producing or is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical. Aquifers may also be exempted if they have a total dissolved solids (TDS) content that is greater than 3,000 mg/L and less than 10,000 mg/L and are not reasonably expected to supply a public water system [40 CFR 146.4(c)]. However, even if an aquifer meets the criteria in 40 CFR 146.4, EPA may disapprove an exemption if other health, safety, or water availability concerns exist. Aquifer exemptions associated with oil- and gas-related injection (Class II activities) typically extend a quarter to one half-mile from the well bore.

The Class VI Rule amended 40 CFR 146.4 to add criteria at 40 CFR 146.4(d) for expanding the areal extent of an existing aquifer exemption for a Class II well that is being transitioned to a Class VI well (see Section 5.1). The Class VI Rule requires that aquifer exemption expansion requests be treated as substantial revisions to a state's primacy program under 40 CFR 145.32 and must therefore be signed by the EPA Administrator (see Section 5.3 for additional information about the EPA review and approval process).

The Class VI Rule precludes the issuance of new aquifer exemptions for GS projects. However, the Class VI Rule does allow for the expansion of the areal extent of existing aquifer exemptions where an aquifer exemption was previously issued for a Class II ER operation. This offers some flexibility in selection of GS sites and provides a mechanism for ER operations injecting into exempted aquifers to expand the exemption and continue injecting if their well is re-permitted as a Class VI well for the purpose of GS. Such exemptions must meet the criteria at 40 CFR 144.7 and 40 CFR 146.4(d).

5.1 Aquifer Exemptions and GS Projects

Owners or operators who wish to transition their Class II ER wells to Class VI wells can request that EPA expand the areal extent of an existing aquifer exemption associated with the Class II well [40 CFR 144.7(d)]. Following approval of the expansion of the areal extent of an aquifer exemption, the owner or operator must meet all of the requirements for Class VI wells.

Expansion of the areal extent of an aquifer exemption is an option limited under 40 CFR 146.4 to Class II projects injecting into exempted aquifers and that are transitioning from Class II to Class VI; however, in no other circumstances are aquifer exemptions permissible for Class VI wells. In no cases will injection into non-exempted USDWs or any injection that endangers USDWs be permitted [40 CFR 146.86(a)]. Furthermore, if the previously exempted aquifer/injection zone is above or between USDWs, the owner or operator must apply for an injection depth waiver in addition to the application for an aquifer exemption expansion (see the requirements for injection depth waivers at 40 CFR 146.95) as these requirements address unique and independent USDW protection requirements. For additional information on applying for injection depth waivers, see the *UIC Program Class VI Well Injection Depth Waivers Guidance.*

5.2 Applying to Expand the Areal Extent of an Aquifer Exemption

To continue injecting for the purpose of GS into an aquifer that has been exempted for ER, an owner or operator will need to apply to expand the areal extent of the aquifer exemption. In addition to defining the areal limits of the expanded aquifer exemption per 40 CFR 144.7(d)(1), an owner or operator must submit information to support a determination that the proposed exemption meets the criteria at 40 CFR 146.4(d).

The paragraphs below present information and recommendations for how applicants can submit information to demonstrate that the proposed aquifer exemption expansion meets the requirements at 40 CFR 146.4(d), including meeting the requirements for applying to expand the areal extent of an existing aquifer exemption (per 40 CFR 144.7(d)(1)) and supporting an evaluation of the request (per 40 CFR 144.7(d)(2)). Many types of information are recommended in these sections; however EPA anticipates that much of this information would be generated or collected as part of the site characterization or Class VI permit application process.

Defining the New Limits of the Aquifer Exemption per 40 CFR 144.7(d)

In the request to expand the areal extent of an existing aquifer exemption, the owner or operator must, per 40 CFR 144.7(d)(1), define and describe, in geographic and/or geometric terms that are clear and definite, all aquifers or parts of aquifers that are to be designated as exempted using the criteria at 40 CFR 146.4(d). Because of the potentially larger volumes of carbon dioxide to be injected for a Class VI GS project and the fact that there will be no associated production of the carbon dioxide to reduce pressures in the injection formation, it is likely that the areal extent of a Class VI aquifer exemption will need to be larger than the existing Class II aquifer exemption.

The areal extent of a Class VI aquifer exemption expansion should be based upon the predicted extent of the injected carbon dioxide plume and any mobilized fluids that may result in degradation of water quality over the lifetime of the project [40 CFR 144.7(d)(2)(ii)]. To ensure that all areas potentially impacted by the injection activity are exempted, EPA recommends that the delineation be informed by the computational modeling performed for the AoR determination required at 40 CFR 146.84(c)(1), and that owners or operators perform modeling prior to requesting an expansion of the areal extent of an existing aquifer exemption and request the exemption of an area that is at least as expansive as the maximum extent of the carbon dioxide plume and pressure front over the life of the project.

Importantly, determination of the expanded exemption area should take into account the migration of the dissolved carbon dioxide plume and all associated fluids that may degrade water quality. See 40 CFR 144.6(d)(2). Such fluids may extend beyond the separate-phase plume and pressure front. Thus, the new area of the requested aquifer exemption expansion may be larger than the AoR for the Class VI well.

To define and describe the area of the expanded aquifer exemption in terms that are clear and definite and support the UIC Program Director's evaluation of the request at 40 CFR 144.6(d)(2), EPA recommends that owners or operators provide a narrative description, maps, illustrations, or other information, including:

- Regional and local maps showing the areal extent of the current aquifer exemption and the area of the requested expansion. Maps may be submitted specifically for the aquifer exemption, or narrative may be provided that references a highlighted area on maps provided as part of the overall permit application required at 40 CFR 146.82. Maps should show the desired lateral limits of the aquifer exemption expansion;

- Perpendicular cross sections to demonstrate the stratigraphic and structural characteristics of the aquifer in the region of the expansion. Cross sections may be used to illustrate the thickness of the aquifer in the area of the aquifer exemption; and

- A discussion of any structures or other features that differ between the original aquifer exemption area and the requested expansion area.

The owner or operator may provide a synopsis of the results of the computational modeling conducted to support the AoR delineation required at 40 CFR 146.84(c)(1), including a map showing the anticipated AoR and the requested aquifer exemption expansion area.

The owner or operator should bear in mind that, due to the nature of GS operations, it is EPA's intention that only one aquifer exemption expansion should be granted for a GS project—at the time that the Class VI permit application is submitted. Thus, an owner or operator should not plan to continually expand an aquifer exemption for a Class VI operation and instead should use conservative assumptions in the computational modeling and define an area for the expanded aquifer exemption that is sufficiently large to account for possible changes to the computational model that may arise during AoR reevaluations over the life of the GS project.

In identifying the expanded aquifer exemption area, the owner or operator should make use of all relevant information gathered and used to support site characterization and AoR delineation. EPA strongly recommends that the owner or operator take into account uncertainties in data inputs for the model and model parameters and consider the upper and lower limits of the AoR predictions. Sensitivity analyses performed as part of the AoR modeling effort will likely indicate a range of predictions that will help owners or operators understand which parameters most strongly influence model predictions. Understanding these sources of uncertainty may help in determining how to accommodate future AoR model estimates in the requested aquifer exemption expansion.

The potential role of geologic features should be considered. For example, data for facies analysis provided as part of the site characterization information required at 40 CFR 146.82(a)(3)(iii) may indicate preferential flow paths that could affect transport of separate-phase carbon dioxide. Certain types of structural traps might be expected to limit separate-phase plume and fluid movement and could function as reasonable boundaries to the exempted area under permitted operating conditions. Such geologic features will have been incorporated into the conceptual model developed for AoR delineation; awareness of the site conceptual model may help in anticipating where the greatest uncertainties lie and how the AoR and fluid migration might change over time. Further information on AoR determination is provided in the *UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance.*

Informing a Determination that the Proposed Exemption Meets the Criteria at 40 CFR 146.4(d)

An owner or operator seeking to expand the areal extent of an existing aquifer exemption should submit information to support a determination that the proposed area of the expanded aquifer exemption meets all of the following criteria at 40 CFR 146.4(d):

- It does not currently serve as a source of drinking water;
- The TDS content of the ground water is more than 3,000 mg/L and less than 10,000 mg/L; and
- It is not reasonably expected to supply a public water system.

The sections below provide recommended approaches for how the owner or operator can compile the information necessary to support a determination that an expansion of the areal extent of an aquifer exemption is appropriate.

Not Currently a Source of Drinking Water

Information must be provided to demonstrate that the portion of the aquifer proposed for exemption "does not currently serve as a source of drinking water" [40 CFR 146.4(d)(1)]. EPA interprets water that currently *serves as a source* of drinking water to include water that is being withdrawn at the time of the application *and* water that will be withdrawn in the future by wells that are currently in existence. The initial area of the exempted aquifer would have already been established as not serving as a source of drinking water. EPA recommends that the owner or operator review information submitted in the original aquifer exemption application concurrent with an assessment of the new area for which the aquifer exemption expansion is requested to meet the requirements at 40 CFR 146.4(d). This may be accomplished by providing information on water suppliers and private drinking water wells in the surrounding region and their source waters.

The types of information that may be useful to submit to support a determination that the area proposed for exemption "does not currently serve as a source of drinking water" in the surrounding area include:

- Names and contact information for drinking water utilities;
- Numbers and locations of production wells and the aquifers in which they are screened;

- Locations of private drinking water wells;
- Maps(s) of the region showing the locations of drinking water wells and the proposed exemption area;
- Cross sections of the region showing the aquifers being used for drinking water and their stratigraphic relationship to the injection formation and the proposed aquifer exemption area; and
- Local and regional population numbers, along with associated surface land uses (e.g., neighborhoods, businesses, cities).

Information about drinking water utilities should be available on municipal websites if owners or operators are not already familiar with drinking water providers in the surrounding region. Water systems may also be located using EPA's Safe Drinking Water Information System (SDWIS) at http://www.epa.gov/enviro/facts/sdwis/search.html, which allows searching by county. Locations of both public and private water supply wells may be obtainable through records of state well permits; however, some of this information may not be publicly available to owners or operators (i.e., for reasons related to water security). Owners or operators may also contact a state's department of health or environmental protection or other relevant agency and request a well search. Hydrogeologic maps and related information may be obtained from state geological surveys, state departments of environmental protection, or the U.S. Geological Survey (USGS). The *UIC Program Class VI Well Injection Depth Waivers Guidance* provides further details on obtaining information about water supplies and about local and regional hydrogeology.

TDS of More than 3,000 mg/L and Less than 10,000 mg/L

The TDS content of the originally-exempted area (i.e., exempted for the Class II operation) should have been established in the original aquifer exemption application. The owner or operator is encouraged to review the original application materials for data to verify that the TDS of the ground water in the formation is more than 3,000 mg/L and less than 10,000 mg/L. The owner or operator should provide data and analyses to support a finding that the ground water in the proposed aquifer exemption expansion area is more than 3,000 mg/L TDS and that the criterion at 40 CFR 146.4(d)(2) is therefore met. If the TDS concentration in the proposed aquifer exemption expansion area is greater than 10,000 mg/L, that portion of the formation is not a USDW, and an aquifer exemption is not needed. If the TDS concentration is lower than 3,000 mg/L, an expansion of the areal extent of an aquifer exemption cannot be granted because it would not meet the requirement for the TDS content to be greater than 3,000 mg/L [40 CFR 146.4(d)(2)].

If the aquifer has been thoroughly characterized in the region of the requested aquifer exemption, analyses of ground water from relevant portions of the proposed expansion area may already be available. Also, some states, e.g., in the western United States, have statewide data on the lowermost USDWs within the state. This information may be out of date, but may provide a starting point for this effort.

In some cases, where analyses have not been conducted or are not available, other data and analyses will be needed to support a determination that the TDS is greater than 3,000 mg/L TDS. It may be necessary for the owner or operator to obtain and submit new values for TDS by sampling the ground water in the expanded exemption area or by estimating the TDS concentration from other data such as well logs. Some of this work may already have been done as part of the site characterization process for the GS project (see the *UIC Program Class VI Well Site Characterization Guidance*).

EPA recommends that the owner or operator submit recent data, including:

- Maps of the region showing sample locations with TDS concentrations;
- Original laboratory reports, if available; and
- New laboratory reports, if additional samples were taken.

Maps showing the extent of the AoR and proposed aquifer exemption area, along with relevant cross sections, are discussed above. Appropriate features should be highlighted, and a narrative that describes available information and substantiates evidence that TDS concentrations in the proposed aquifer exemption area meet the requirements should be provided.

Not Reasonably Expected to Supply a Public Water System

EPA recommends that the owner or operator submit information to support a determination that the aquifer is not reasonably expected to supply a public water system [40 CFR 146.4(d)(3)]. Factors that can impact the likelihood of an aquifer serving as a future source of drinking water include use for hydrocarbon production (i.e., because it is unlikely that waters in the vicinity of oil and gas operations are used as drinking water sources); being situated at a depth or location where recovery of water for drinking water is impractical; or being too contaminated to be remediated for human consumption. It is likely that the original aquifer exemption associated with Class II wells was based on the presence of economically valuable mineral, hydrocarbon, or geothermal energy resources. Information and data about such usage within the expanded area may include:

- Maps showing the locations of economically viable and potentially economically viable deposits that are also USDWs (shown on geologic maps and cross-sections);
- Logging (e.g., geophysical well logs) results or drill stem test results indicating that commercially producible quantities of oil and/or natural gas are present;

- Maps and descriptions of past or current hydrocarbon exploration, production, or recovery activities in the area, including injection and production well locations, API numbers and/or production information;

- Data from oil and gas producers that are in the area or that produce from the formation(s) of interest;

- Information on whether future recovery of mineral resources or hydrocarbons has been permitted and/or planned;

- Production history of other wells in the vicinity that produce from the horizon in question;

- Maps and cross sections showing the locations of aquifers that are not currently used but that may be used in the future (if appropriate) and their relationship to the injection zone, both laterally and stratigraphically;

- Future projections of regional water usage, population and urban development, if available; and

- Potential changes in water supply: new wells, aquifer storage and recovery activities, or population growth that could require that water be purchased from other water systems. Information provided on these changes should demonstrate that sufficient supply and resources exist to support future use as demand increases or changes without using the exempted aquifer.

Information on oil and gas resources or development may be available from USGS's Mineral Resources Data System, USGS's National Oil and Gas Assessment, or the U.S. Bureau of Land Management (BLM)'s Oil and Gas Management Program. Useful information may also be available from state geological surveys and state oil and gas agencies.

5.3 Evaluating Requests for Aquifer Exemption Expansions

States or tribes with primacy will review the request and, if the information submitted supports a determination that an aquifer exemption is warranted, they may identify the aquifer or portion of an aquifer as exempt, after notice and opportunity for a public hearing [40 CFR 144.7(b)(3)]. The state or tribe would then submit a request for a revision to their state program to the appropriate EPA regional office. (A state or tribe without primacy would forward the exemption request to the EPA regional office that implements the UIC Program.)

No designation of an expansion to the areal extent of a Class II aquifer exemption for GS injection will be final unless approved by the EPA Administrator as a revision to the applicable federal UIC Program under 40 CFR part 147 as a substantial revision of an approved state UIC Program [40 CFR 145.32]. For additional information on establishing and revising state UIC Programs, see the *UIC Program Class VI Primacy Manual for State Directors*.

As discussed above, 40 CFR 144.7(d)(2) outlines the information that the UIC Program Director must consider in evaluating requests to expand the areal extent of a Class II aquifer exemption:

- **The current and potential future use of the aquifer or portion of aquifer to be exempted** [40 CFR 144.7(d)(2)(i)]. The UIC Program Director and EPA will verify that no drinking water wells are located in the injection formation in the proposed aquifer exemption expansion area. They will also consider anticipated future water supplies for the area and the availability of other suitable sources that could meet future needs, verifying that the information provided adequately describes the future use of the area to be exempted.

- **The predicted extent of the injected carbon dioxide plume and any mobilized fluids that could degrade water quality** [40 CFR 144.7(d)(2)(ii)] and endanger USDWs that are outside of the exempted area (and therefore afforded protection under SDWA). The UIC Program Director and EPA will ascertain whether the injected plume and pressure front or mobilized fluids could potentially migrate outside of the exempted area over the lifetime of the GS project. This will involve evaluating the proposed expanded area of the aquifer exemption in concert with the computational AoR modeling results.

- **Whether the areal extent of the expanded aquifer exemption is sufficient to account for any possible revisions to the computational model during required AoR reevaluations** [40 CFR 144.7(d)(2)(iii)]. The UIC Program Director and EPA should consider carefully the factors used in delineating the expanded aquifer exemption area, including model sensitivity analyses and the conceptual model of the site geology. This information can provide insight regarding whether and how much predictions may change as a result of the model updates required at 40 CFR 146.84(e).

- **Any relevant information submitted for an injection depth waiver** [40 CFR 144.7(d)(2)(iv)]. Maps and cross sections of the project area can provide information relevant to both the aquifer exemption expansion and the injection depth waiver. Similarly, information on current and future water use required in the waiver application report will support an assessment of whether the proposed exemption area meets the criteria at 40 CFR 146.4(d).

6 References

Advanced Resources International (ARI). 2006. Evaluating the potential for 'Game Changer' Improvements in Oil Recovery Efficiency from CO_2 Enhanced Oil Recovery. Prepared for U.S. DOE, Office of Oil and Natural Gas, Office of Fossil Energy. February 2006. Available on the Internet at: http://www.fe.doe.gov/programs/oilgas/publications/eor_co2/Game_Changer_Document_2_06_with_appendix.pdf.

Benson S.M. 2007. Overview of Geological Storage of Carbon Dioxide. National Research Council Geological Storage Roundtable. Washington DC, May 31, 2007.

Carey, J.W., M. Wigand, S.J. Chipera, G. WoldeGabriel, R. Pawar, P.C. Lichtner, S.C. Wehner, M.A. Raines, and G.D. Guthrie, Jr. 2007. Analysis and Performance of Oil Well Cement with 30 years of CO_2 Exposure from the SACROC Unit, West Texas, USA. International Journal of Greenhouse Gas Control. 1: 75–85.

Celia, M.A., S. Bachu, J.M. Nordbotten, S.E. Gasda, and H.K. Dahle. 2004. Quantitative estimation of CO_2 leakage from geological storage: Analytical models, numerical models, and data needs. p. 663–671. *In* M. Wilson et al. (ed.) Proc. Int. Conf. on Greenhouse Gas Control Technologies, 7th, Vancouver, BC, Canada. 5–9 Sept. 2004. Vol. 1. Elsevier Science, Amsterdam.

Crow, W., D.B. Williams., B. Carey, M. Celia, and S. Gasda. 2009. Wellbore integrity analysis of a natural carbon dioxide producer. Energy Procedia. 1: 3561-3569.

Carbon Sequestration Leadership Forum (CSLF), 2009. Phase I Final Report from CSLF Risk Assessment Task Force. CSLF-T-2009-04. http://www.cslforum.org/publications/documents/RATF_Phase1FinalReport.pdf.

Deel, D. K. Mahajan, C.R. Mahoney, H.G. McIlvried, and R.D. Srivastava. 2007. Risk assessment and management for long-term storage of CO_2 in geologic formations – United States Department of Energy R&D. Systemics, Cybernetics and Informatics, 5(1), 79-84. Available on the Internet at: http://www.iiisci.org/journal/CV$/sci/pdfs/P807791.pdf.

DOE. 2010. Carbon Sequestration Atlas of the United States and Canada. Third Edition (Atlas III).

Doughty, C., Freifeld, B.M., Trautz, R.C. Site characterization for CO2 geologic storage and vice versa: the Frio brine pilot, Texas, USA as a case study. J. Environ Geol. 2007.

Energy Information Administration (EIA). 2009. Annual Energy Review 2008. Energy Information Administration, U.S. Department of Energy. Washington, DC. DOE/EIA-0384 (2008). June 2009.

Electric Power Research Institute (EPRI). 1999. Enhanced Oil Recovery Scoping Study, EPRI, Palo Alto, CA: 1999. TR-113836.

Jessen, K., A.R. Kovscek, and F.M. Orr, Jr. 2005. Increasing CO_2 storage in oil recovery. Energy Conversion & Management. 46: 293–311.

Klusman, R. 2003. Evaluation of leakage potential from carbon dioxide EOR/sequestration project. Energy Conversion & Management. 44: 1921-1940.

Knauss, K.G., J.W. Johnson, and C.I. Steefel. 2005. Evaluation of the impact of CO_2, co-contaminant gas, aqueous fluid and reservoir rock interactions on the geologic sequestration of CO_2. Chem. Geol. 217: 339–350.

Kutchko, B., B.R. Strazisar, D.A. Dzombak, G. Lowry, and N. Thaulow. 2007. Degradation of well cement by CO_2 under geologic sequestration conditions. Environmental Science and Technology. 41: 4787-4792.

Kutchko, B., B.R. Strazisar, N. Huerta, G. Lowry, D. Dzombak, and N. Thaulow. 2009. CO_2 reaction with hydrated Class H well cement under geologic sequestration conditions: Effects of flyash admixtures. Environmental Science and Technology. 32: 3947–3952.

LeNeveu, D.M., F.B. Walton, J.C. Tait, M.I. Sheppard, and K. Haug. 2006. The role of the upper geosphere in mitigating CO_2 surface releases in wellbore leakage scenarios. Prepared for Natural Resources Canada, CANMET Energy Technology Centre – Devon. Available on the Internet at: http://www.netl.doe.gov/publications/proceedings/06/carbon-seq/Poster%20208.pdf.

Meyer, J. 2007. Summary of Carbon Dioxide Enhanced Oil Recovery (CO2EOR) Injection Well Technology. Prepared for the Amer. Petroleum Institute. Wash., DC. Available on the Internet at: http://www.gwpc.org/e-library/documents/co2/API%20CO2%20Report.pdf.

NETL. 2010. Carbon Dioxide Enhanced Oil Recovery Untapped Domestic Energy Supply and Long Term Carbon Storage Solution. Available on the Internet at: http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_eor_primer.pdf. March 2010.

NETL. 2011. Best Practices for: Risk Analysis and Simulation for Geologic Storage of CO_2. DOE/NETL-2011/1459. Available on the Internet at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM_RiskAnalysisSimulation.pdf.

Nicot, J-P., P. Saripalli, R. Bouroullec, H. Castellanos, S. Hovorka, S. Lakshminarasimhan, and J. Paine. 2006. Development of Science-Based Permitting Guidance for Geological Sequestration of CO_2 in Deep Saline Aquifers Based on Modeling and Risk Assessment: Final Scientific Report. DOE Agreement No. DE-FC25-04NT42210. Available on the Internet at: http://www.osti.gov/bridge/servlets/purl/901785-qgxT7R/901785.pdf.

Nicot, J.-P., Oldenburg, C.M., Bryant, S.L., Hovorka, S.D., Pressure perturbations from geologic carbon sequestration: Area-of-review boundaries and borehole leakage driving forces. Presented at the 9th International Conference on Greenhouse Gas Control Technologies (GHGT-9), Washington, D.C., November 16-20, 2008. GCCC Digital Publication Series #08-03h.

Nordbotten, J.M., M.A. Celia, and S. Bachu. 2004. Analytical solutions for leakage rates through abandoned wells. Water Resource. Res. 40:W04204, doi:10.1029/2003WR002997.

OGJ (Oil and Gas Journal). 2008. SPECIAL REPORT: More US EOR projects start but EOR production continues decline. Oil and Gas Journal, April 21, 2008.

Oldenburg, C.M., S.L. Bryant, and J-P Nicot. 2009. Certification framework based on effective trapping for geologic carbon sequestration. International Journal of Greenhouse Gas Control. 3(4): 444-457.

Saripalli, P., and P. McGrail. 2002. Semi-analytical approaches to modeling deep well injection of CO_2 for geologic sequestration. Energy Conversion & Management. 43: 185–198.

Stauffer, P.H., H.S. Viswanthan, R.J. Pawar, M.L. Klasky, and G.D. Guthrie. CO2-PENS: A CO_2 sequestration system model supporting risk-based decisions. Proceedings of the 16th International Conference on Computational Methods in Water Resources; Copenhagen, Denmark, June 19-22, 2006. Available on the Internet at: http://www.goldsim.com/downloads/documents/LANL_CO2_Paper.pdf.

Walton, F.B., J.C. Tait, D. LeNeveu, and M.I. Sheppard. 2004. Geological storage of CO_2: a statistical approach to assessing performance and risk. In: E.S. Rubin, D.W. Keith and C.F. Gilboy (Eds.), Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, Sept 5-9, 2004, Vancouver, Canada. Volume 1: Peer-Reviewed Papers and Plenary Presentations, IEA Greenhouse Gas Programme, Cheltenham, UK, 2004. Available on the Internet at: http://www.granite.mb.ca/~sheppard/GHGT7.pdf.

Xu, T., J.A. Apps, K. Pruess, and H. Yamamoto. 2007. Numerical modeling of injection and mineral trapping of CO_2 with H_2S and SO_2 in a sandstone formation. Chem. Geol. 242: 319–346.

Zhou, Q., J.T. Birkholzer, C.-F. Tsang, and J. Rutqvist. 2008. A method for quick assessment of CO_2 storage capacity in closed and semi-closed saline formations. Int. J. Greenhouse Gas Control. 2: 626–639.

Appendix I.

Detailed Comparison of Class II and Class VI Regulations

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
AoR Delineation and Corrective Action: Class II and VI requirements differ in methodology for AoR delineation and application of corrective action. For Class II wells the AoR is determined either by a modified Theis equation or by a fixed radius; and all corrective action must be performed before a permit is issued. For Class VI wells, the AoR is determined by computational modeling of multiphase fluid flow; and corrective action can be phased.	The AoR is determined either by a *zone of endangering influence* or a *fixed radius* [40 CFR 146.6]. • *Zone of endangering influence* is defined differently under Class II requirements for well permits and area permits, and determined based on pressures in the injection zone that may cause the migration of the injection and/or formation fluid into an USDW. The delineation of this zone depends on some hydrogeologic parameters and use of a mathematical model, such as a modified Theis equation. It should be conducted for an injection time period equal to the expected life of the injection well or pattern. • *Fixed radius* is defined as a fixed distance of at least ¼ mile around an injection well or a width of ¼ mile for the circumscribing area around an injection area. While determining the fixed radius, factors to be considered are: chemistry of injected and formation fluids, hydrogeology, population and ground water use and dependence and historical practices in the area. The owner or operator must identify all known wells within the AoR that penetrate the proposed injection zone, or in the case of wells operating over the fracture pressure of the injection formation, all known wells within the AoR that penetrate formations affected by the increase in pressure. [40 CFR 146.24(a)(3)]. For new wells, the owner or operator must also submit a plan describing corrective action necessary to prevent fluid movement into USDWs [40 CFR 146.24]. The Director will consider the following for evaluating the adequacy of corrective action: nature and volume of fluid; nature of native fluids or by-products of injection; potentially affected population; geology; hydrogeology; history of the injection operations; completion	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 is based on available site characterization, monitoring, and operational data [40 CFR 146.84(a)]. It is computed for the time period starting from commencement of injection activities until plume movement ceases, until pressure differentials no longer can cause the movement of fluids into a USDW, or until the end of a fixed time period determined by the Director [40 CFR 146.84(c)]. Additionally, the owner or operator must prepare, maintain and comply with an AoR and corrective action plan, periodically reevaluate the delineation, and perform corrective action [40 CFR 146.84(b)]. Corrective action requires identification of all penetrations and ensuring that abandoned wells in the AoR have been plugged in a manner that prevents the movement of fluids into or between USDWs [40 CFR 146.84(c) and (d)]. Under the Class VI Rule, corrective action can be addressed on a phased basis [40 CFR 146.84(b)].

<table>
<tr><th colspan="3">Detailed Comparison of Requirements for Class II and VI Wells</th></tr>
<tr><th>Requirement Type</th><th>Class II Requirements</th><th>Class VI Requirements</th></tr>
<tr><td>AoR Delineation and Corrective Action (continued)</td><td>and plugging records; abandonment procedures in effect at the time the well was abandoned; and hydraulic connections with USDWs [40 CFR 146.7 and 40 CFR 144.55].</td><td></td></tr>
<tr><td>Mechanical Integrity: Mechanical integrity is defined in identical for both Class II and Class VI wells. However, there are differences in methods used for testing the mechanical integrity.</td><td>Methods used for evaluating the absence of significant leaks [40 CFR 146.8(b)]:
• Following an initial pressure test, monitoring of the tubing-casing annulus pressure with sufficient frequency while maintaining an annulus pressure different from atmospheric pressure measured at the surface; or
• Pressure test with liquid or gas; or
• Records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for certain specified types of enhanced recovery wells.

Methods used for determining the absence of significant fluid movement into an USDW [40 CFR 146.8(c)]:
• The results of a temperature or noise log; or
• Cementing records demonstrating the presence of adequate cement to prevent such migration.</td><td>Methods used for evaluating the absence of significant leaks [40 CFR 146.89(b)]:
• An initial annular pressure test; and
• Continuous monitoring of the following: 1) injection pressure, rate, injected volumes; 2) pressure on the annulus between tubing and long string casing; and 3) annulus fluid volume.

Methods used for determining the absence of significant fluid movement (at least once per year) [40 CFR 146.89(c)]:
• An approved tracer survey such as an oxygen-activation log; or
• A temperature or noise log.

Additionally if required by the Director, and at a frequency specified in the testing and monitoring plan, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long string casing. [40 CFR 146.89(d)].</td></tr>
</table>

<table>
<tr><th colspan="3">Detailed Comparison of Requirements for Class II and VI Wells</th></tr>
<tr><th>Requirement Type</th><th>Class II Requirements</th><th>Class VI Requirements</th></tr>
<tr><td rowspan="2">Plugging and Abandonment: Well plugging requirements between Class II and VI wells differ in the methods that can be used to plug wells. Class VI well requirements include additional testing and activities prior to plugging. Also, owners or operators are required to give notices prior to plugging and submit a report after plugging.</td><td>The well shall be plugged with cement plugs which will be placed by one of the following [40 CFR 146.10(a)]:
• The Balance method;
• The Dump Bailer method;
• The Two-Plug method; or
• An alternative method approved by the Director.

The well to be abandoned shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director, prior to the placement of the cement plug(s) [40 CFR 146.10(a)].</td><td rowspan="2">Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test [40 CFR 146.92(a)].

The owner or operator of a Class VI well must prepare, maintain, and comply with a well plugging plan that will include all of the following [40 CFR 146.92(b)]:
• Appropriate tests or measures for determining bottomhole reservoir pressure;
• Appropriate testing methods to ensure external mechanical integrity as specified in 40 CFR 146.89;
• The type and number of plugs to be used;
• The placement of each plug, including the elevation of the top and bottom of each plug; and
• The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and
• The method of placement of the plugs.

The owner or operator must notify the Director in writing at least 60 days before well plugging (Notice of intent to plug) [40 CFR 146.92(c)].

Within 60 days after plugging, the owner or operator must submit a plugging report to the Director [40 CFR 146.92(d)].</td></tr>
<tr><td>Prior to granting approval for the plugging and abandonment of a Class II well the Director shall consider the following information [40 CFR 146.24(d)]:
• The type, and number of plugs to be used;
• The placement of each plug including the elevation of top and bottom;
• The type, grade, and quantity of cement to be used;
• The method of placement of the plugs; and
• The procedure to be used to meet the requirements of 40 CFR 146.10(c).</td></tr>
</table>

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Construction: Siting, casing and cementing, and logging, sampling, and testing requirements for Class VI wells are more comprehensive and explicitly defined. They differ in methodologies for testing and information to be collected.	Siting: All new Class II wells shall be sited in such a fashion that they inject into a formation which is separated from any USDW by a confining zone that is free of known open faults or fractures within the AoR [40 CFR 146.22(a)].	Siting: The wells shall be sited in areas with a suitable geologic system [40 CFR 146.83(a)] and comprised of: • An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream; • Confining zone(s) free of transmissive faults or fractures and 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 in the confining zone(s). The Director may require identification and characterization of additional zones [40 CFR 146.83(b)].
	Casing and Cementing: Casing and cementing materials used are required to prevent fluid movement into or between USDW and shall be designed for the life expectancy of the well. Information considered by the Director for newly drilled wells [40 CFR 146.22(b)] includes: • Depth to the injection zone; • Depth to the bottom of all USDWs; and • Estimated maximum and average injection pressures. The Director may also consider: • Nature of formation fluids; • Lithology of injection and confining zones; • External pressure, internal pressure, and axial loading; • Hole size; • Size and grade of all casing strings; and • Class of cement. Existing or newly converted Class II wells in existing fields are	Casing and Cementing: Casing and cementing materials used are required to prevent fluid movement into or between USDWs and shall be designed for the life of the GS project with sufficient structural strength. All well materials shall be compatible with fluids, meeting or exceeding standards. Information considered by the Director include [40 CFR 146.86(b)(1)*]: • Depth to the injection zone(s); • Injection pressure, external pressure, internal pressure, and axial loading; • Hole size; • Size and grade of all casing strings (wall thickness including any threaded casing sections, external diameter, nominal weight, length, joint specification, and construction material); • Corrosiveness of the carbon dioxide stream and formation fluids; • Down-hole temperatures; • Lithology of injection and confining zone(s);

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Construction (continued)	subject to the regulatory controls that existed at the time of drilling, if the wells are in compliance with those controls and well injection will not result in the movement of fluid unto a USDW so as to create a significant health risk. Newly drilled wells in existing fields are subject to requirements of the state for casing and cementing, if they meet such requirements and well injection will not result in the movement of fluids into a USDW so as to create a significant health risk. There are no tubing and packer requirements explicitly specified in Class II regulations.	• Type or grade of cement and cement additives; and • Quantity, chemical composition, and temperature of the carbon dioxide stream. Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cementing [40 CFR 146.86(b)(2)*]. At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages [40 CFR 146.86(b)(3)*] or any other approved method [40 CFR 146.86(b)(4)*]. Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the GS project [40 CFR 146.86(b)(5)*]. Class VI well owners or operators must comply with the tubing and packer requirements listed at 40 CFR 146.86(c) related to materials used, their placement in the well, and reporting requirements. The Director may request additional information from the owner or operator and subsequently determine and specify additional requirements for tubing and packer.
	Logging, Sampling, and Testing [40 CFR 146.22]: Appropriate logs and other tests must be conducted during the drilling and construction of new Class II wells. A descriptive report interpreting the results of that portion of those logs and tests which specifically relate to (1) an USDW and the confining zone adjacent to it, and (2) the injection and adjacent formations shall be prepared by a knowledgeable log analyst and submitted to the Director [40 CFR 146.22(f)]. At a minimum, these logs and	Logging, Sampling, and Testing [40 CFR 146.87*]: During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys, and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under 40 CFR 146.86 and to establish accurate baseline data against which future

<table>
<tr><th colspan="3">Detailed Comparison of Requirements for Class II and VI Wells</th></tr>
<tr><th>Requirement Type</th><th>Class II Requirements</th><th>Class VI Requirements</th></tr>
<tr><td>Construction (continued)</td><td>tests include:
Deviation checks on all holes at sufficiently frequent intervals.
Other tests and logs:
For surface casing: electric and caliper logs before casing is installed; and a cement bond, temperature, or density log after the casing is set and cemented.
For intermediate and long strings of casing: electric, porosity and gamma ray logs before the casing is installed; fracture finder logs; and a cement bond, temperature, or density log after the casing is set and cemented.
For new Class II wells or projects, the following information concerning the injection formation: fluid pressure, estimated fracture pressure, and physical and chemical characteristics of the injection zone.</td><td>measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests [40 CFR 146.87(a)*]. At a minimum, these logs and tests include:
Deviation checks during drilling on all holes at sufficiently frequent intervals.
Before and upon installation of the surface casing:
Resistivity, spontaneous potential, and caliper logs before the casing is installed; and
A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.
Before and upon installation of the long string casing:
Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and
A cement bond and variable density log, and a temperature log after the casing is set and cemented.
A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:
A pressure test with liquid or gas;
A tracer survey such as oxygen-activation logging;
A temperature or noise log; and
A casing inspection log.
Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.
The owner or operator must take whole borehole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must</td></tr>
</table>

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Construction (continued)		submit to the Director a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information. • The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s). • At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s): o Fracture pressure; o Other physical and chemical characteristics of the injection and confining zone(s); and o Physical and chemical characteristics of the formation fluids in the injection zone(s). • Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s): o A pressure fall-off test; and o A pump test; or o Injectivity tests. • The owner or operator must provide the Director with the opportunity to witness all logging and. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Operating, Monitoring, and Reporting Requirements: The requirements under the Class VI Rule are more comprehensive and detailed for operating, monitoring, and reporting. Class VI Rule also outlines the recordkeeping requirements whereas there are no recordkeeping requirements under Class II regulations.	Operating: Operating requirements [40 CFR 146.23(a)] for Class II wells specify that: • Injection pressure at the wellhead cannot exceed a maximum value to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone. In no case can injection pressure cause the movement of injection or formation fluids into a USDW. • Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Operating [40 CFR 146.88]: • Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. All stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit. [40 CFR 146.88(a)] • Injection between the outermost casing protecting USDWs and the well bore is prohibited. [40 CFR 146.88(b)] • The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain a pressure on the annulus that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs. [40 CFR 146.88(c)] • Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times. [40 CFR 146.88(d)] • The owner or operator must install and use [40 CFR 146.88(e)]: o Continuous recording devices to monitor: The injection pressure; the rate by volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and o Alarms and automatic surface shut-off systems or, at

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Operating, Monitoring, and Reporting Requirements (continued)		the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and o Alarms and automatic down-hole shut-off systems for wells located offshore but within state territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit. • If a shutdown (*i.e.,* down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring indicates that the well may be lacking mechanical integrity, the owner or operator must do all of the following [40 CFR 146.88(f)]: o Immediately cease injection; o Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone; o Notify the Director within 24 hours; o Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and o Notify the Director when injection is scheduled to resume.
	Monitoring: Monitoring requirements [40 CFR 146.23(b)] include: • Monitoring of the nature of injected fluids at time intervals sufficiently frequent to yield data representative of their	Monitoring [40 CFR 146.90]: The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan. Testing and monitoring for the project must include all of the following:

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**

Operating, Monitoring, and Reporting Requirements (continued)	• characteristics;
	• Observation of injection pressure, flow rate, and cumulative volume with the following minimum frequencies:
	   o Weekly for produced fluid disposal operations;
	   o Monthly for enhanced recovery operations;
	   o Daily during the injection of liquid hydrocarbons and injection for withdrawal of stored hydrocarbons; and
	   o Daily during the injection phase of cyclic steam operations.
	   o The owner or operator is also required to record one observation of injection pressure, flow rate, and cumulative volume at a reasonable interval, no greater than 30 days.
	• A demonstration of mechanical integrity pursuant to 40 CFR 146.8 at least once every five years during the life of the injection well;
	• Maintenance of all monitoring results until the next permit review (see 40 CFR 144.52(a)(5)); and
	• Hydrocarbon storage and enhanced recovery may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner or operator demonstrates that manifold monitoring is comparable to individual well monitoring.
		• Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;
		• Installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added; and
		• Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis (see details at section 40 CFR 146.90(c)).
		• Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) or additional identified zones including:
		   o The location and number of monitoring wells; and
		   o The monitoring frequency and spatial distribution of monitoring wells.
		• A demonstration of external mechanical integrity at least once per year until the injection well is plugged and, if required by the Director, a casing inspection log at a frequency established in the testing and monitoring plan.
		• A pressure fall-off test at least once every five years unless more frequent testing is required by the Director.
		• Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:
		   o Direct methods in the injection zone(s); and
		   o Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools).
		• The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW (see details at 40 CFR 146.90(h)).

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Operating, Monitoring, and Reporting Requirements (continued)		• The Director may require any additional monitoring. • The owner or operator is required to periodically review the testing and monitoring plan. In no case can the review of the testing and monitoring plan be conducted less than once every five years. Based on this review, the Director may require an amended testing and/or monitoring plan that will demonstrate that no amendment is needed (see section 40 CFR 146.90(j) for details). • The owner or operator must provide the Director with a quality assurance and surveillance plan for all testing and monitoring requirements.

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Operating, Monitoring, and Reporting Requirements (continued)	Reporting: Reporting requirements [40 CFR 146.23(c)] include: • An annual report to the Director summarizing the monitoring results, including monthly records of injected fluids, and any major changes in characteristics or sources of injected fluid. • Owners or operators of hydrocarbon storage and ER projects may report on a field or project basis rather than an individual well basis where manifold monitoring is used.	Reporting [40 CFR 146.91]: For each permitted Class VI well, the owner or operator must submit: • Semi-annual reports containing: o Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data; o Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure; o A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit; o A description of any event which triggers a shut-off device, the source that triggered the shut-off, and the response taken; o The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project; o Monthly annulus fluid volume added; and o The results of implementing the monitoring requirements detailed above. • Report, within 30 days, the results of: o Periodic tests of mechanical integrity; o Any well workover; and o Any other test of the injection well conducted by the permittee as required by the Director. • Report, within 24 hours: o Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW; o Any noncompliance with a permit condition, or malfunction of the injection system, which may cause

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Operating, Monitoring, and Reporting Requirements (continued)		fluid migration into or between USDWs; o Any triggering of a shut-off system (*i.e.,* down-hole or at the surface); o Any failure to maintain mechanical integrity; or o For surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any indicated release of carbon dioxide to the atmosphere or biosphere. • Owners or operators must notify the Director in writing 30 days in advance of: o Any planned well workover; o Any planned stimulation activities, other than stimulation for formation testing; and o Any other planned test of the injection well conducted by the permittee. • Owner or operators must submit all required reports, submittals, and notifications to EPA in an electronic format approved by EPA. • Records shall be retained by the owner or operator as follows: o All data collected under 40 CFR 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure. o Data on the nature and composition of all injected fluids collected pursuant to 40 CFR 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period. o Monitoring data collected pursuant to 40 CFR 146.90(b) through (i) shall be retained for 10 years after it is collected. Well plugging reports, post-injection site care data, including, if appropriate, data and information

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Operating, Monitoring, and Reporting Requirements (continued)		collected and used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report prepared pursuant to requirements at 40 CFR 146.93(f) and (h) shall be retained for 10 years following site closure. • The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Information to be considered by the Director (Permit Application): Permit application requirements overlap in some areas, such as the requirement of a map showing the injection well and the AoR. However, Class VI requirements include additional information, such as detailed hydrogeologic properties of the formations, additional maps and cross-sections, baseline geochemical data, and various plans.	**40 CFR 146.24 Information to be considered by the Director** Certain maps, cross-sections, tabulations of wells within the AoR, and other data may be included in the application by reference provided they are current, readily available to the Director (for example, in the permitting agency's files), and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section is to be submitted to the Administrator.	**40 CFR 146.82 Required Class VI permit information** For converted Class I, Class II, or Class V experimental wells, certain maps, cross-sections, tabulations of wells within the AoR and other data may be included in the application by reference provided they are current, readily available to the Director, and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section must be submitted to the Regional Administrator.

	Prior to the issuance of a permit for an existing Class II well to operate or the construction or conversion of a new Class II well:
	• Information required in 40 CFR 40 CFR 144.31 and 40 CFR 144.31(g);
	• A map showing the injection well or project area for which a permit is sought and the applicable AoR. Within the AoR, the map must show the number or name and location of all existing producing wells, injection wells, abandoned wells, dry holes, and water wells. The map may also show surface bodies of waters, mines (surface and subsurface), quarries and other pertinent surface features including residences and roads, and faults if known or suspected. Only information of public record and pertinent information known to the applicant is required on this map. This requirement does not apply to existing Class II wells; and
	• A tabulation of data reasonably available from public records or otherwise known to the applicant on all wells within the AoR included on the map which penetrate the proposed injection zone or, in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the AoR which penetrate formations affected by the increase in pressure. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and
		Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well:
		• Information required in 40 CFR 144.31(e)(1) through (6) of this chapter;
		• A map showing the injection well for which a permit is sought and the applicable AoR. Within the AoR, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, state, tribal, and territory boundaries, and roads. The map should also show known and suspected faults. Only information of public record is required to be included on this map;
		• Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:
		    o Maps and cross sections of the AoR;
		    o The location, orientation, and properties of known and suspected faults and fractures that may transect the confining zone(s) in the AoR and a discussion of a

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**

Information to be considered by the Director (continued)	completion, and any additional information the Director may require. In cases where the information would be repetitive and the wells are of similar age, type, and construction the Director may elect to only require data on a representative number of wells. This requirement does not apply to existing Class II wells.
	• Proposed operating data:
	  o Average and maximum daily rate and volume of fluids to be injected.
	  o Average and maximum injection pressure; and
	  o Source and an appropriate analysis of the chemical and physical characteristics of the injection fluid.
	• Appropriate geological data on the injection zone and confining zone including lithologic description, geological name, thickness and depth;
	• Geologic name and depth to bottom of USDWs which may be affected by the injection;
	• Schematic or other appropriate drawings of the surface and subsurface construction details of the well;
	• In the case of new injection wells, the corrective action proposed; and
	• A certificate that the applicant has assured through a performance bond or other appropriate means, the resources necessary to close the plug or abandon the well.
	
	In addition the Director may consider the following:
	• Proposed formation testing program;
	• Proposed stimulation program;
	• Proposed injection procedure;
	• Proposed contingency plans, if any, to cope with well failures so as to prevent migration of contaminating fluids into an USDW; and
	• Plans for meeting the monitoring requirements.
		determination that they would not interfere with containment;
		  o 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 or other geophysical surveys, well logs, and names and lithologic descriptions;
		  o Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);
		  o Information on the regional seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and
		  o Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.
		• A tabulation of all wells, active and inactive, within the AoR which penetrate the injection or confining zone(s). Such data must include a description of each well's status (active or inactive), type, construction, date drilled, location, depth, associated borelog, record of plugging and/or completion, and any additional information the Director may require;
		• 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;
		• Baseline geochemical data on subsurface formations, including all USDWs in the AoR;

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**

Information to be considered by the Director (continued)		• For the proposed GS site:
		  o Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;
		  o Average and maximum anticipated injection pressure;
		  o The source(s) of the carbon dioxide stream; and
		  o An analysis of the chemical and physical characteristics of the proposed carbon dioxide stream.
		• Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s);
		• Proposed stimulation program, a description of stimulation fluids to be used and discussion of a determination that stimulation will not interfere with containment;
		• Proposed procedure to outline steps necessary to conduct injection operation;
		• Schematics or other appropriate drawings of the proposed surface and subsurface construction details of the well;
		• Proposed injection well construction procedures;
		• Proposed AoR and corrective action plan;
		• A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements;
		• Proposed testing and monitoring plan;
		• Proposed injection well plugging plan;
		• Proposed post-injection site care and site closure plan;
		• At the Director's discretion, a demonstration of an alternative post-injection site care timeframe;
		• Proposed emergency and remedial response plan;
		• A list of contacts, submitted to the Director, for those states, tribes, and territories identified to be within the AoR of the Class VI project; and

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Information to be considered by the Director (continued)		• Any other information requested by the Director. • The Director shall notify, in writing, any states, tribes, or territories within the AoR of the Class VI project based on information provided in the permit.
	Prior to granting approval for the operation of a Class II well, the Director shall consider the following information: • All available logging and testing program data on the well; • A demonstration of mechanical integrity; • The anticipated maximum pressure and flow rate at which the permittee will operate. • The results of the formation testing program; • The proposed injection procedure; and • For new wells, the status of corrective action on defective wells in the AoR.	Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information: • The final AoR based on modeling, using data obtained during logging and testing of the well and the formation; • 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; • 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; • The results of the formation testing program; • Final proposed injection well construction; • The status of corrective action on wells in the AoR; • All available logging and testing program data on the injection well; • The demonstration of mechanical integrity; • Any updates to the proposed AoR and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan; and • Any other information requested by the Director.

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Financial Responsibility	A certificate that the applicant has assured through a performance bond or other appropriate means, the resources necessary to close plug or abandon the injection well [40 CFR 146.24(a)(9)].	The owner or operator must demonstrate, to the satisfaction of the Director, and maintain financial responsibility by using instrument(s), such as trust funds, surety bonds, letter of credit, insurance, self insurance, escrow account, any other instruments to cover the cost of corrective action, injection well plugging, post injection site care and site closure, emergency and remedial response (see 40 CFR 146.85 for details).

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Post Injection Site Care and Site Closure (PISC): Class VI Rule includes a specific section for the post injection site care and site closure, whereas Class II requirements do not include any specific regulations for PISC.	None.	Class VI Rule Post Injection Site Care requirements are [40 CFR 146.93]: • The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure. • The site will be monitored following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered. • *Demonstration of alternative post-injection site care timeframe.* At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. • *Notice of intent for site closure.* The owner or operator must notify the Director in writing at least 120 days before site closure. • After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW. • The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. • Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search. • The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period.

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Emergency and Remedial Response: Class VI requirements include a separate section for emergency and remedial response, whereas Class II requirements do not include this topic.	None.	Class VI Rule emergency and remedial response requirements are [40 CFR 146.94]: • As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan. • If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must: o Immediately cease injection; o Take all steps reasonably necessary to identify and characterize any release; o Notify the Director within 24 hours; and o Implement the emergency and remedial response plan approved by the Director. • The Director may allow the owner or operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs. • The owner or operator shall periodically review the emergency and remedial response plan at least once every five years.

Detailed Comparison of Requirements for Class II and VI Wells		
Requirement Type	**Class II Requirements**	**Class VI Requirements**
Injection Depth Waivers: Under the Class VI Rule, owners or operators can apply for a waiver to inject above the lowermost USDW. However, there are no specific requirements restricting he injection depth for Class II wells.	None.	In seeking a waiver of the requirement to inject below the lowermost USDW, the owner or operator must submit a supplemental report concurrent with permit application (see 40 CFR 146.95 for details).

*Pursuant to requirements at 40 CFR 146.81(c), owners or operators seeking to convert existing wells to Class VI geologic sequestration wells must demonstrate to the Director that the wells were engineered and constructed to meet the requirements at 40 CFR 146.86(a) and ensure protection of USDWs, in lieu of requirements at 40 CFR 146.86(b) and 146.87(a). See Section 4 of this guidance for additional information on requirements for transitioning wells.