ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 124, 144, 145, 146, and 147

[EPA–HQ–OW–2008–0390 FRL–9232–7]

RIN 2040–AE98

Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes minimum Federal requirements under the Safe Drinking Water Act (SDWA) for underground injection of carbon dioxide (CO_2) for the purpose of geologic sequestration (GS). GS is one of a portfolio of options that could be deployed to reduce CO_2 emissions to the atmosphere and help to mitigate climate change. This final rule applies to owners or operators of wells that will be used to inject CO_2 into the subsurface for the purpose of long-term storage. It establishes a new class of well, Class VI, and sets minimum technical criteria for the permitting, geologic site characterization, area of review (AoR) and corrective action, financial responsibility, well construction, operation, mechanical integrity testing (MIT), monitoring, well plugging, post-injection site care (PISC), and site closure of Class VI wells for the purposes of protecting underground sources of drinking water (USDWs). The elements of this rulemaking are based on the existing Underground Injection Control (UIC) regulatory framework, with modifications to address the unique nature of CO_2 injection for GS. This rule will help ensure consistency in permitting underground injection of CO_2 at GS operations across the United States and provide requirements to prevent endangerment of USDWs in anticipation of the eventual use of GS to reduce CO_2 emissions to the atmosphere and to mitigate climate change.

DATES: This regulation is effective January 10, 2011. For purposes of judicial review, this final rule is promulgated as of 1 p.m., Eastern time on December 24, 2010, as provided in 40 CFR 23.7.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OW–2008–0390. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the OW Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OW Docket is (202) 566–2426.

FOR FURTHER INFORMATION CONTACT: Mary Rose (Molly) Bayer, Underground Injection Control Program, Drinking Water Protection Division, Office of Ground Water and Drinking Water (MC–4606M), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: (202) 564–1981; fax number: (202) 564–3756; e-mail address: *bayer.maryrose@epa.gov.* For general information, visit the Underground Injection Control Geologic Sequestration Web site at *http://www.epa.gov/safewater/uic/wells_sequestration.html.*

SUPPLEMENTARY INFORMATION:

I. General Information

This regulation affects owners or operators of injection wells that will be used to inject CO_2 into the subsurface for the purposes of GS. Regulated categories and entities include, but are not limited to, the following:

Category	Examples of regulated entities
Private	Owners or Operators of CO_2 injection wells used for Class VI GS.
Private	Owners or Operators of existing CO_2 injection wells transitioning from Class I, II, or Class V injection activities to Class VI GS.

This table is not intended to be an exhaustive list; rather it provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria found at § 146.81 in the rule section of this action. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Abbreviations and Acronyms

AoR Area of Review
BLM United States Department of the Interior, Bureau of Land Management
BOEMRE United States Department of the Interior, Bureau of Ocean Energy Management, Regulation and Enforcement
CAA Clean Air Act
CBI Confidential Business Information
CCS Carbon Capture and Storage
CERCLA Comprehensive Environmental Response, Compensation, and Liability Act
CO_2 Carbon Dioxide
DOE United States Department of Energy
ECBM Enhanced Coal Bed Methane
EFAB Environmental Financial Advisory Board
EGR Enhanced Gas Recovery
EIS Environmental Impact Statement
EISA Energy Independence and Security Act of 2007
EO Executive Order
EOR Enhanced Oil Recovery
EPA United States Environmental Protection Agency
ER Enhanced Recovery
FPR Federally Permitted Releases
GAO General Accountability Office
GHG Greenhouse Gas
GS Geologic Sequestration
Gt CO_2 Gigatons CO_2
GWPC Ground Water Protection Council
HHS United States Department of Health and Human Services
ICR Information Collection Request
IOGCC Interstate Oil and Gas Compact Commission
IPCC Intergovernmental Panel on Climate Change
IRS United States Internal Revenue Service
LBNL Lawrence Berkeley National Laboratory
Mg/L Milligrams per liter
MI Mechanical Integrity
MIT Mechanical Integrity Test
MMS United States Department of the Interior, Minerals Management Service
MPRSA Marine Protection, Research, and Sanctuaries Act of 1972
MRA Miscellaneous Receipts Act
MRR Mandatory Reporting Rule
MRV Monitoring, Reporting, and Verification
NAICS North American Industry Classification System
NASA National Aeronautics and Space Administration
NCER National Center for Environmental Research
NDWAC National Drinking Water Advisory Council
NEPA National Environmental Protection Act
NETL National Energy Technology Laboratory
NGO Non-Governmental Organization
NIWG National Indian Work Group
NOAA National Oceanic and Atmospheric Administration
NODA Notice of Data Availability
NOI Notice of Intent

NTC National Tribal Caucus
NTTAA National Technology Transfer and Advancement Act of 1995
NTWC National Tribal Water Council
O&M Operation and Maintenance
OAR Office of Air and Radiation
OCS Outer Continental Shelf
OCSLA Outer Continental Shelf Lands Act
OMB Office of Management and Budget
ORD Office of Research and Development
PBMS Performance Based Measurement System
Pg Petagram
PISC Post-Injection Site Care
PRA Paperwork Reduction Act
PWSS Public Water System Supervision
QASP Quality Assurance and Surveillance Plan
RA Regulatory Alternative
RCRA Resource Conservation and Recovery Act
RCSP Regional Carbon Sequestration Partnership
RFA Regulatory Flexibility Act
RIC Regional Indian Coordinators
SDWA Safe Drinking Water Act
STAR Science To Achieve Results
STC3 State-Tribal Climate Change Council
SWP Southwest Regional Partnership on Carbon Sequestration
TCLP Toxicity Characteristic Leaching Procedure
TDS Total Dissolved Solids
TNW Tangible Net Worth
UIC Underground Injection Control
UICPG#83 Underground Injection Control Program Guidance # 83
UMRA Unfunded Mandates Reform Act
USDW Underground Source of Drinking Water
USGS United States Department of the Interior, United States Geological Survey
WRI World Resources Institute

Definitions

Annulus: The space between the well casing and the wall of the bore hole; the space between concentric strings of casing; the space between casing and tubing.

Area of review (AoR): 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 § 146.84.

Automatic shut-off device: A valve which closes when a pre-determined pressure or flow value is exceeded. Shut-off devices in injection wells can automatically shut down injection activities preventing an excursion outside of the permitted values.

Ball valve: A valve consisting of a hole drilled through a ball placed in between two seals. The valve is closed when the ball is rotated in the seals so the flow path no longer aligns and is blocked.

Biosphere: The part of the Earth's crust, waters, and atmosphere that supports life.

Buoyancy: Upward force on one phase (*e.g.,* a fluid) produced by the surrounding fluid (*e.g.,* a liquid or a gas) in which it is fully or partially immersed, caused by differences in pressure or density.

Capillary force: Adhesive force that holds a fluid in a capillary or a pore space. Capillary force is a function of the properties of the fluid, and surface and dimensions of the space. If the attraction between the fluid and surface is greater than the interaction of fluid molecules, the fluid will be held in place.

Caprock: See confining zone.

Carbon dioxide plume: The extent underground, in three dimensions, of an injected carbon dioxide stream.

Carbon dioxide (CO_2) stream: 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 does not apply to any carbon dioxide stream that meets the definition of a hazardous waste under 40 CFR part 261.

Casing: The 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 outermost 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.

Cement: 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.

Confining zone: 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).

Corrective action: The use of Director-approved methods to ensure that wells within the area of review do not serve as conduits for the movement of fluids into USDWs.

Corrosive: Having the ability to wear away a material by chemical action. Carbon dioxide mixed with water forms carbonic acid, which can corrode well materials.

Dip: The angle between a planar feature, such as a sedimentary bed or a fault, and the horizontal plane. The dip of subsurface rock layers can provide clues as to whether injected fluids may be contained.

Director: The person responsible for permitting, implementation, and compliance of the UIC program. For UIC programs administered by EPA, the Director is the EPA Regional Administrator or his/her delegatee; for UIC programs in Primacy States, the Director is the person responsible for permitting, implementation, and compliance of the State, Territorial, or Tribal UIC program.

Ductility: The ability of a material to sustain stress until it fractures.

Enhanced Coal Bed Methane (ECBM) recovery: The process of injecting a gas (*e.g.,* CO_2) into coal, where it is adsorbed to the coal surface and methane is released. The methane can be captured and produced for economic purposes; when CO_2 is injected, it adsorbs to the surface of the coal, where it remains trapped or sequestered.

Enhanced Oil or Gas Recovery (EOR/EGR): Typically, the process of injecting a fluid (*e.g.,* water, brine, or CO_2) into an oil or gas bearing formation to recover residual oil or natural gas. The injected fluid thins (decreases the viscosity) and/or displaces extractable oil and gas, which is then available for recovery. This is also used for secondary or tertiary recovery.

Flapper valve: A valve consisting of a hinged flapper that seals the valve orifice. In Class VI wells, flapper valves can engage to shut off the flow of the CO_2 when acceptable operating parameters are exceeded.

Formation or geological formation: A layer of rock that is made up of a certain type of rock or a combination of types.

Geologic sequestration (GS): The long-term containment of a gaseous, liquid or supercritical carbon dioxide stream in subsurface geologic formations. This term does not apply to CO_2 capture or transport.

Geologic sequestration project: For the purpose of this regulation, 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 § 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 EOR/EGR aquifer exemption pursuant to §§ 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.

Geophysical surveys: The use of geophysical techniques (*e.g.,* seismic, electrical, gravity, or electromagnetic surveys) to characterize subsurface rock formations.

Injectate: The fluids injected. For the purposes of this rule, this is also known as the CO_2 stream.

Injection zone: A geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic sequestration project.

Lithology: The description of rocks, based on color, mineral composition and grain size.

Mechanical integrity (MI): 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).

Mechanical Integrity Test: 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.

Model: 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 CO_2 within the subsurface, accounting for the properties and fluid content of the subsurface formations and the effects of injection parameters.

Packer: A mechanical device that seals the outside of the tubing to the inside of the long string casing, isolating an annular space.

Pinch-out: A situation where a formation thins to zero thickness.

Pore space: Open spaces in rock or soil. These are filled with water or other fluids such as brine (*i.e.,* salty fluid). CO_2 injected into the subsurface can displace pre-existing fluids to occupy some of the pore spaces of the rocks in the injection zone.

Post-injection site care: Appropriate monitoring and other actions (including corrective action) needed following cessation of injection to ensure that USDWs are not endangered, as required under § 146.93.

Pressure front: 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 CO_2 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.

Saline formations: Subsurface geographically extensive sedimentary rock layers saturated with waters or brines that have a high total dissolved solids (TDS) content (*i.e.,* over 10,000 mg/L TDS).

Site closure: The point/time, as determined by the Director following the requirements under § 146.93, at which the owner or operator of a GS site is released from post-injection site care responsibilities.

Sorption (absorption, adsorption): Absorption refers to gases or liquids being incorporated into a material of a different state; adsorption is the adhering of a molecule or molecules to the surface of a different molecule.

Stratigraphic zone (unit): A layer of rock (or stratum) that is recognized as a unit based on lithology, fossil content, age or other properties.

Supercritical fluid: A fluid above its critical temperature (31.1°C for CO_2) and critical pressure (73.8 bar for CO_2). Supercritical fluids have physical properties intermediate to those of gases and liquids.

Total Dissolved Solids (TDS): 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.

Transmissive fault or fracture: A fault or fracture that has sufficient permeability and vertical extent to allow fluids to move between formations.

Trapping: The physical and geochemical processes by which injected CO_2 is sequestered in the subsurface. Physical trapping occurs when buoyant CO_2 rises in the formation until it reaches a layer that inhibits further upward migration or is immobilized in pore spaces due to capillary forces. Geochemical trapping occurs when chemical reactions between dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals.

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

Viscosity: The property of a fluid or semi-fluid that offers resistance to flow. As a supercritical fluid, CO_2 is less viscous than water and brine.

Table of Contents

II. Background

Today's action finalizes minimum Federal requirements under SDWA for injection of CO_2 for the purpose of GS. The purpose of the rulemaking is to ensure that GS is conducted in a manner that protects USDWs from endangerment. GS refers to a suite of technologies that can be deployed to reduce CO_2 emissions to the atmosphere and help mitigate climate change. Due to the large CO_2 injection volumes anticipated at GS projects, the relative buoyancy of CO_2, its mobility within subsurface geologic formations, its corrosivity in the presence of water, and the potential presence of impurities in the captured CO_2 stream, the Agency has determined that tailored requirements, modeled on the existing UIC regulatory framework, are necessary to manage the unique nature of CO_2 injection for GS. This final rule applies to owners or operators of wells that will be used to inject CO_2 into the subsurface for the purpose of GS.

To support today's final regulatory action, EPA proposed *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells* (73 FR 43492) on July 25, 2008; and the Agency published a supplemental publication, *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Notice of Data Availability and Request for Comment* (74 FR 44802) on August 31, 2009. Final Class VI requirements are informed, in part, by comments and information submitted in response to these publications.

Today's rule defines a new class of injection well (Class VI), along with technical criteria that tailor the existing UIC regulatory framework to address the unique nature of CO_2 injection for GS. It sets minimum technical criteria for Class VI wells to protect USDWs from endangerment, including:

- Site characterization that includes an assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that Class VI wells are located in suitable formations.
- Computational modeling of the AoR for GS projects that accounts for the physical and chemical properties of the injected CO_2 and is based on available site characterization, monitoring, and operational data.
- Periodic reevaluation of the AoR to incorporate monitoring and operational data and verify that the CO_2 plume and the associated area of elevated pressure are moving as predicted within the subsurface.
- Well construction using materials that can withstand contact with CO_2 over the life of the GS project.
- Robust monitoring of the CO_2 stream, injection pressures, integrity of the injection well, ground water quality and geochemistry, and monitoring of the CO_2 plume and position of the pressure front throughout injection.
- Comprehensive post-injection monitoring and site care following cessation of injection to show the position of the CO_2 plume and the associated area of elevated pressure to demonstrate that neither pose an endangerment to USDWs.
- Financial responsibility requirements to ensure that funds will be available for all corrective action, injection well plugging, post-injection site care (PISC), site closure, and emergency and remedial response.

Today's rule will help ensure consistency in permitting underground injection of CO_2 at GS operations across the United States (US) and provide requirements to prevent endangerment of USDWs in anticipation of the potential role of carbon capture and storage (CCS) in mitigating climate change. Today's action also briefly discusses the relationship between today's rule and other Federal and State activities related to GS and CCS in Sections II.C and D, and E.2.b, and III.F.2.

A. Why is EPA taking this regulatory action?

1. What is GS?

GS is the process of injecting CO_2 into deep subsurface rock formations for long-term storage. It is part of the process known as CCS.

CO_2 is first captured from fossil-fueled power plants or other emission sources. To transport captured CO_2 for GS, operators typically compress CO_2 to convert it from a gaseous state to a supercritical state (IPCC, 2005; IEA, 2008). CO_2 exists as a supercritical fluid at high pressures, and in this state it exhibits properties of both a liquid and a gas. After capture and compression, the CO_2 is delivered to the sequestration site, frequently by pipeline, or alternatively using tanker trucks or ships (WRI, 2007; IEA, 2008).

At the GS site, the CO_2 is injected into deep subsurface rock formations through one or more wells, using technologies developed and refined by the oil, gas, and chemical manufacturing industries over the past several decades. EPA believes that many owners or operators will inject CO_2 in a supercritical state to depths greater than 800 meters (2,645 feet) for the purpose of maximizing capacity and storage.

When injected into an appropriate receiving formation, CO_2 is sequestered by a combination of trapping mechanisms, including physical and geochemical processes (Benson, 2008). Physical trapping occurs when the relatively buoyant CO_2 rises in the formation until it reaches a stratigraphic zone with low permeability (*i.e.,* geologic confining system) that inhibits further upward migration. Physical trapping can also occur as residual CO_2 is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces. A portion of the CO_2 will dissolve from the pure fluid phase into native ground water and hydrocarbons. Preferential sorption occurs when CO_2 molecules attach to the surfaces of coal and certain organic-rich shales, displacing other molecules such as methane. Geochemical trapping occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals (IPCC, 2005). The timeframe over which CO_2 will be trapped by these mechanisms depends on properties of the receiving formation and the injected CO_2 stream.

The effectiveness of physical CO_2 trapping is demonstrated by natural analogs in a range of geologic settings where CO_2 has remained trapped for millions of years (Holloway *et al.,* 2007). For example, CO_2 has been trapped for more than 65 million years under the Pisgah Anticline, northeast of the Jackson Dome in Mississippi and Louisiana (IPCC, 2005). Other natural CO_2 sources include the following geologic domes: McElmo Dome, Sheep Mountain, and Bravo Dome in Colorado and New Mexico.

Many of the injection and monitoring technologies that may be applicable to GS are commercially available today and will be more widely demonstrated over the next 10 to 15 years (Dooley *et al.,* 2009). The oil and natural gas industry in the United States has over 35 years of experience of injection and monitoring of CO_2 in the deep subsurface for the purposes of enhancing oil and natural gas production. This experience provides a strong foundation for the injection and monitoring technologies that will be needed for commercial-scale CCS. US and international experience with enhanced recovery (ER) and commercial CCS projects, as well as ongoing research, demonstration, and deployment programs throughout the world, provide critical experience and information to inform the safe injection of CO_2. For additional information about these projects, see section II.E.

Although CCS is occurring now on a relatively small scale, it could play a larger role in mitigating greenhouse gas (GHG) emissions from a wide variety of stationary sources. According to the Inventory of US Greenhouse Gas Emissions and Sinks: 1990–2007, stationary sources contributed 67 percent of the total CO_2 emissions from fossil fuel combustion in 2007 (USEPA, 2008a). These sources represent a wide variety of sectors amenable to CO_2 capture: electric power plants (existing and new), natural gas processing facilities, petroleum refineries, iron and steel foundries, ethylene plants, hydrogen production facilities, ammonia refineries, ethanol production facilities, ethylene oxide plants, and cement kilns. Furthermore, 95 percent of the 500 largest stationary sources are within 50 miles of a candidate GS reservoir (Dooley *et al.,* 2008). Estimated GS capacity in the United States is over 3,500 Gigatons CO_2 (Gt CO_2) (DOE NETL, 2007), although the actual capacity may be lower once site-specific technical and economic considerations are addressed. Even if only a fraction of that geologic capacity is used, CCS would play a sizeable role in mitigating US GHG emissions.

2. Why is GS under consideration as a climate change mitigation technology?

Climate change is happening now, and the effects can be seen on every continent and in every ocean. While certain effects of climate change can be beneficial, particularly in the short term, current and future effects of climate change pose considerable risks to human health and the environment. There is now clear evidence that the Earth's climate is warming (USEPA, 2010):

- Global surface temperatures have risen by 1.3 degrees Fahrenheit (°F) over the last 100 years.
- Worldwide, the last decade has been the warmest on record.
- The rate of warming across the globe over the last 50 years (0.24°F per decade) is almost double the rate of warming over the last 100 years (0.13°F per decade).

Most of this recent warming is very likely the result of human activities. Many human activities release greenhouse gases into the atmosphere (such as the combustion of fossil fuels). The levels of these gases are increasing at a faster rate than at any time in hundreds of thousands of years.

Fossil fuels are expected to remain the mainstay of energy production well into the 21st century, and increased concentrations of CO_2 are expected unless energy producers reduce CO_2 emissions to the atmosphere. For example, CCS would enable the continued use of coal in a manner that greatly reduces the associated CO_2 emissions while other safe and affordable alternative energy sources are developed in the coming decades. The development and deployment of clean coal technologies including CCS will be a key to achieving domestic emissions reductions.

GS is one of a portfolio of options that could be deployed to reduce CO_2 emissions to the atmosphere and help to mitigate climate change. Other options include energy conservation, efficiency improvements, and the use of alternative fuels and renewable energy sources. Ensuring that GS is done in a manner that is protective of USDWs will ensure the safety and efficacy of CO_2 injection for GS.

While predictions about large-scale availability and the rate of CCS project deployment are subject to uncertainty, EPA analyses of Congressional climate change legislative proposals (the American Power Act of 2010 and the American Clean Energy and Security Act H.R. 2454 of 2009, both in the 111th Congress) indicate that CCS has the potential to play a significant role in climate change mitigation scenarios. For example, analysis of the American Power Act indicates that CCS technology could account for 10 percent of CO_2 emission reductions in 2050 (USEPA, 2010f). These results indicate that CCS could play an important role in achieving national greenhouse gas reduction goals.

Today's final rule provides minimum Federal requirements for the injection of CO_2 to protect USDWs from endangerment as this key climate mitigation technology is developed and deployed. It clarifies requirements that apply to CO_2 injection for GS, provides consistency in requirements across the US, and affords transparency about what requirements apply to owners or operators.

3. What are the unique risks to USDWs associated with GS?

Large CO_2 injection volumes associated with GS, the buoyant and mobile nature of the injectate, the potential presence of impurities in the CO_2 stream, and its corrosivity in the presence of water could pose risks to USDWs. The purpose of today's Class VI requirements for GS is to ensure the protection of USDWs, recognizing that an improperly managed GS project has the potential to endanger USDWs. Proper siting, well construction, operation, and monitoring of GS projects are therefore necessary to reduce the risk of USDW contamination.

It is expected that GS projects will inject large volumes of CO_2. These volumes will be much larger than are typically injected in other well classes regulated through the UIC program, and could cause significant pressure increases in the subsurface. Supercritical or gaseous CO_2 in the subsurface is buoyant, and thus would tend to flow upwards if it were to come into contact with a migration pathway, such as a fault, fracture, or improperly constructed or plugged well. However, the pressures induced by injection will also influence CO_2 and mobilized fluids to flow away from the injection well in all directions, including laterally, upwards and downwards. When CO_2 mixes with formation fluids, a percentage of it will dissolve. The resulting aqueous mixture of CO_2 and water will sink due to a density differential between the mixture and the surrounding fluids. CO_2 is also highly mobile in the subsurface (*i.e.,* has a very low viscosity), and, in the presence of water, CO_2 can be corrosive. These properties (of CO_2), as well as the large volumes that may be injected for GS result in several unique challenges for protection of USDWs in the vicinity of GS sites from endangerment.

While CO_2 itself is not a drinking water contaminant, CO_2 in the presence of water forms a weak acid, known as carbonic acid, that, in some instances, could cause leaching and mobilization of naturally-occurring metals or other contaminants from geologic formations into ground water (*e.g.,* arsenic, lead, and organic compounds). Another potential risk to USDWs is the presence of impurities in the captured CO_2 stream, which may include drinking water contaminants such as hydrogen sulfide or mercury. Additionally, pressures induced by injection may force native brines (naturally occurring salty water) into USDWs, causing degradation of water quality and affecting drinking water treatment processes. Research studies have shown that the potential migration of injected CO_2 or formation fluids into a USDW could cause impairment through one or several of these processes (*e.g.,* Birkholzer *et al.,* 2008a).

Today's action addresses endangerment to USDWs by establishing new minimum Federal requirements for the proper management of CO_2 injection and storage in several program areas, including permitting, site characterization, AoR and corrective action, well construction, mechanical integrity testing (MIT), financial responsibility, monitoring, well plugging, PISC, and site closure. EPA believes that proper GS project management will appropriately mitigate potential risks of endangerment to USDWs posed by injection activities.

B. Under what authority is this rulemaking promulgated?

Today's rule is focused on USDW protection under the authority of Part C of SDWA (SDWA, section 1421 *et seq.,* 42 U.S.C. 300h *et seq.*). Part C of the SDWA requires EPA to establish minimum requirements for State[1] UIC programs that regulate the subsurface injection of fluids onshore and offshore under submerged lands within the territorial jurisdiction of States[2].

SDWA is designed to protect the quality of drinking water sources in the US and prescribes that EPA issue regulations for State UIC programs that contain "minimum requirements for effective programs to prevent underground injection which endangers drinking water sources" (42 U.S.C. 300h *et seq.*). Congress further defined endangerment as follows:

> Underground injection endangers drinking water sources if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons (SDWA, section 1421(d)(2)).

Under this authority, the Agency promulgated a series of UIC regulations at 40 CFR parts 144 through 148 for federally approved UIC programs. The chief goal of any Federally approved UIC program (whether administered by a State, Territory, Tribe or EPA) is the protection of USDWs. This includes not only those formations that are presently being used for drinking water, but also those that can reasonably be expected to be used in the future. EPA has defined through its UIC regulations that USDWs are underground aquifers with less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) and which contain a sufficient quantity of ground water to supply a public water system (40 CFR 144.3). Section 1421(b)(3)(A) of the SDWA also provides that EPA's UIC regulations shall "permit or provide for consideration of varying geologic, hydrological, or historical conditions in different States and in different areas within a State."

EPA promulgated administrative and permitting regulations, now codified in 40 CFR parts 144 and 146, on May 19, 1980 (45 FR 33290), and technical requirements, in 40 CFR part 146, on June 24, 1980 (45 FR 42472). The regulations were subsequently amended on August 27, 1981 (46 FR 43156), February 3, 1982 (47 FR 4992), January 21, 1983 (48 FR 2938), April 1, 1983 (48 FR 14146), May 11, 1984 (49 FR 20138), July 26, 1988 (53 FR 28118), December 3, 1993 (58 FR 63890), June 10, 1994 (59 FR 29958), December 14, 1994 (59 FR 64339), June 29, 1995 (60 FR 33926), December 7, 1999 (64 FR 68546), May 15, 2000 (65 FR 30886), June 7, 2002 (67 FR 39583), and November 22, 2005 (70 FR 70513).

Under the SDWA, the injection of any "fluid" must meet the requirements of the UIC program. A "fluid" is defined under 40 CFR 144.3 as any material or substance which flows or moves whether in a semisolid, liquid, sludge, gas or other form or state, and includes the injection of liquids, gases, and semisolids (*i.e.,* slurries) into the subsurface. The types of fluids currently injected into wells subject to UIC requirements include: CO_2 for the purposes of enhancing recovery of oil and natural gas, water that is stored to meet water supply demands in dry seasons, and wastes generated by industrial users. CO_2 injected for the purpose of GS is subject to the SDWA.

C. How does this rulemaking relate to the greenhouse gas (GHG) reporting program?

Today's rulemaking under SDWA authority complements the CO_2 Injection and GS Reporting rulemaking (subparts RR and UU) under the Greenhouse Gas Reporting Program's Clean Air Act (CAA) authority developed by EPA's Office of Air and Radiation (OAR).

The CAA defines EPA's responsibilities for protecting and improving the nation's air quality and the stratospheric ozone layer. The GHG Reporting Program requires reporting of GHG emissions and other relevant information from certain source categories in the U.S. The GHG Reporting Program, which became effective on December 29, 2009, includes reporting requirements for facilities and suppliers in 32 subparts. For more detailed background information on the GHG Reporting Program, see the preamble to the final rule establishing the GHG Reporting Program (74 FR 56260, October 30, 2009).

In a separate action being finalized concurrently with this UIC Class VI rulemaking, EPA is amending 40 CFR part 98, which provides the regulatory framework for the GHG Reporting Program, to add reporting requirements covering facilities that conduct GS (subpart RR) and all other facilities that inject CO_2 underground (subpart UU). This data will inform Agency policy decisions under CAA sections 111 and 112 related to the use of CCS for mitigating GHG emissions. In combination with data from other subparts of the GHG Reporting Program, data from subpart UU and subpart RR will allow EPA to track the flow of CO_2 across the CCS system. EPA will be able to reconcile subpart RR data on CO_2 received with CO_2 supply data in order to understand the quantity of CO_2 supply that is geologically sequestered.

Owners or operators subject to today's rule are required to report under subpart RR. Subpart RR establishes reporting requirements for facilities that inject a CO_2 stream for long-term containment into a subsurface geologic formation, including sub-seabed offshore formations. These facilities are required to develop and implement a site-specific

[1] Reference to "States" includes Tribes and Territories pursuant to 40 CFR 144.3.

[2] The Submerged Lands Act and Territorial Submerged Lands Act define the scope of territorial jurisdiction of States and Territories respectively.

Monitoring, Reporting, and Verification (MRV) plan which, once approved by EPA (in a process separate from the UIC permitting process), would be used to verify the amount of CO_2 sequestered and to quantify emissions in the event that injected CO_2 leaks to the surface. For more information on subpart RR, see *http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.*

UIC requirements and Subpart RR requirements: EPA designed the reporting requirements under subpart RR with consideration of the requirements for Class VI well owners or operators in subpart H of part 146 of today's rule. Subpart RR builds on the Class VI requirements outlined in today's rule with the additional goals of verifying the amount of CO_2 sequestered and collecting data on any CO_2 surface emissions from GS facilities as identified under subpart RR of part 98.

The Agency acknowledges that there are similar data elements that must be reported pursuant to requirements in this action and those required to be reported under subpart RR. Specifically, owners or operators subject to both regulations must report the amount (flow rate) of injected CO_2. The Class VI and subpart RR rules differ, not only in purpose but in the specific requirements for the measurement unit and collection/reporting frequency. The UIC program Class VI rule requires that owners or operators report information on the CO_2 stream to ensure appropriate well siting, construction, operation, monitoring, post-injection site care, site closure, and financial responsibility to ensure protection of USDWS. Under subpart RR, owners or operators must report the amount (flow rate) of injected CO_2 for the mass balance equation that will be used to quantify the amount of CO_2 sequestered by a facility.

TABLE II–1—COMPARISON OF REPORTING REQUIREMENTS UNDER SUBPART RR AND SELECT UIC CLASS VI REQUIREMENTS

Reporting requirement	Subpart RR	UIC Class VI
Quantity of CO_2 transferred onsite	Yes	N/A.
Quantity (flow rate) of CO_2 injected	Yes	Yes.
Fugitive and vented emissions from surface equipment	Yes	N/A.
Quantity of CO_2 produced with oil or natural gas (ER)	Yes	N/A.
Percent of CO_2 estimated to remain with the oil and gas (ER)	Yes	N/A.
Quantity of CO_2 emitted from the subsurface	Yes	N/A.
Quantity of CO_2 sequestered in the subsurface	Yes	N/A.
Cumulative mass of CO_2 sequestered in the subsurface	Yes	N/A.
Monitoring plan for detecting air emissions	Yes	Yes.[1]
Monitoring plan for quantifying air emissions	Yes	N/A.

(1) UIC Class VI rule allows for surface air/soil gas monitoring for USDW protection at the discretion of the UIC Director.

EPA requires reporting of other data to satisfy various programmatic needs. See section III of this preamble and associated requirements in subpart H of part 146 and the preamble to subpart RR for additional information on these specific requirements and their purpose. Table II–1 provides a comparison of the major reporting requirements in subpart RR and the extent to which there is overlap with Class VI requirements. For the monitoring plan listed in Table II–1, EPA will accept a UIC Class VI permit to satisfy certain subpart RR MRV plan requirements. However, the reporter must include additional information to outline how monitoring will achieve surface detection and quantification of CO_2. EPA is pursuing ways to better integrate data management between the UIC and GHG Reporting Programs to ensure that data needs are harmonized and the burden to regulated entities is minimized.

D. How does this rulemaking relate to other federal authorities and GS and CCS activities?

While the SDWA provides EPA with the authority to develop regulations to protect USDWs from endangerment, it does not provide authority to develop regulations for all areas related to GS. EPA received a number of public comments on the proposal (73 FR 43492, July 25, 2008) indicating that the Agency should further explore environmental and regulatory issues beyond the scope of the proposed SDWA requirements for underground injection of CO_2 for GS.

In response to comments and as a result of the presidential memo "A Comprehensive Strategy on Carbon Capture and Storage" (*http://www.whitehouse.gov/the-press-office/presidential-memorandum-a-comprehensive-Federal-strategy-carbon-capture-and-storage*), the Agency continues to evaluate areas of potential applicability of other Federal environmental statutes including, but not limited to, the CAA (discussed in section II.C), the Resource Conservation and Recovery Act (RCRA; discussed in section III.F.2), the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA; discussed in section III.F.2), and the Marine Protection, Research and Sanctuaries Act (MPRSA; discussed in this section) to various aspects of GS and CCS.

Additionally, EPA and the US Department of Energy (DOE) co-chaired the Interagency Task Force on Carbon Capture and Storage to develop a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to 10 commercial demonstration projects online by 2016. The Task Force's report is available at *http://www.whitehouse.gov/administration/eop/ceq/initiatives/ccs.*

This section clarifies the distinction between today's rulemaking and a number of other Federal rulemakings and initiatives.

National Environmental Protection Act (NEPA): The SDWA UIC program is exempt from performing an Environmental Impact Statement (EIS) under section 101(2)(C) and an alternatives analysis under section 101(2)(E) of NEPA under a functional equivalence analysis. See *Western Nebraska Resources Council* v. *US EPA,* 943 F.2d 867, 871–72 (8th Cir. 1991) and EPA Associate General Counsel Opinion (August 20, 1979).

Marine Protection, Research, and Sanctuaries Act (MPRSA) and London Protocol Implementation: Sub-seabed CO_2 injection for GS may, in certain circumstances, be defined as ocean dumping and subject to regulation under the MPRSA. Application of the MPRSA would entail coordination of the permitting processes under the SDWA and MPRSA, pursuant to MPRSA sections 106(a) and (d). The substantive environmental protection requirements of both statutes would need to be satisfied prior to the commencement of GS. The MPRSA was enacted in 1972 and implements the London Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (the "London Convention"). In 1996, the Protocol to the London Convention (the "London Protocol") was established. The Protocol stipulates that sub-seabed GS may be approved provided that: (1) Disposal is into a sub-seabed geologic formation; (2) the CO_2 stream consists overwhelmingly of CO_2, with only incidental associated substances derived from the source material and capture and sequestration process used; and, (3) no wastes or other matter are added for the purpose of disposal. The US has signed, but has not yet ratified, the Protocol. If the Protocol is ratified, and implementing legislation is enacted, EPA, in conjunction with other Federal agencies, will develop any necessary regulations for implementing the provisions relevant to sub-seabed GS.

Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) Outer Continental Shelf Lands Act (OCSLA): BOEMRE, formerly the Minerals Management Service (MMS), an agency within the Department of the Interior, administers the OCSLA. As a result of recent OCSLA amendments by the Energy Policy Act of 2005, the OCSLA provides for the grant of leases, easements, or rights-of-way on the outer continental shelf to the extent that an activity "supports production, transportation, or transmission of energy from sources other than oil and gas" and complies with the other provisions of OCSLA section 8(p). Offshore geologic sequestration of CO_2 on the outer continental shelf may be subject to requirements under the OCSLA.

As indicated in the Report of the Interagency Task Force on Carbon Capture and Storage (2010), ratification of the London Protocol and associated amendment of the MPRSA as well as amendment of the Outer Continental Shelf Lands Act (OCSLA) will ensure a comprehensive statutory framework for the storage of CO_2 on the outer continental shelf.

Bureau of Land Management (BLM) Report to Congress: The BLM, another agency within the Department of Interior, was required by Section 714 of the Energy Independence and Security Act (EISA) of 2007 (Pub. L. 110–140, HR 6) to prepare a report outlining a regulatory framework that could be applied to lands managed by the Bureau for natural resource development, chiefly oil and gas. With assistance from both EPA and the DOE, BLM submitted a Report to Congress titled "Framework for Geological Carbon Sequestration on Public Land" (BLM, 2009). This report affirms BLM's role in appropriately managing Federal lands where GS injection projects may be sited. Additionally, the report makes recommendations regarding approaches for effective regulation of such activities under existing Federal authorities including the SDWA and UIC program requirements.

United States Geological Survey (USGS) GS Capacity Methodology: USGS, another agency within the Department of Interior and the primary Federal agency responsible for national geological research, has been an active participant with DOE and EPA at conferences and workshops on CCS. In 2008, in response to the EISA, USGS initiated development of a methodology for estimating the capacity to store CO_2 in geologic formations of the U.S. While previous capacity estimates published by DOE/National Energy Technology Laboratory (NETL) have been broad in scope (*i.e.,* geologic basin-wide), the USGS is focusing on small-scale, refined estimates. In 2009, USGS published a proposed, risk-based methodology for GS capacity estimation. After input from other agencies and stakeholders, USGS released a final report: *A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage* (USGS, 2010). The report is available at *http://pubs.usgs.gov/of/2010/1127/.* USGS continues to work on capacity estimation as required under the EISA.

Internal Revenue Service (IRS) Guidance for Tax Incentives for GS Projects: In response to the Energy Improvement and Extension Act of 2008, IRS, in consultation with EPA and DOE, issued guidance 2009–44 IRB (IRS, 2009) for taxpayers seeking to claim tax credits for capturing and sequestering CO_2 from a qualified facility in the U.S. Under section 45Q of the Internal Revenue Code, a taxpayer who stores CO_2 under the predetermined conditions may qualify for the tax credit ($10 per metric ton of qualified CO_2 at ER projects; $20 per metric ton of qualified CO_2 for non-ER projects). The taxpayer will be responsible for maintaining records for inspection by the IRS and tax credit amounts will be adjusted for inflation for any taxable year beginning after 2009. The Internal Revenue Service published IRS Notice 2009–83 (available at: *http://www.irs.gov/irb/2009–44_IRB/ar11.html#d0e1860*) to provide guidance regarding eligibility for the section 45Q tax credit, computation of the section 45Q tax credit, reporting requirements for taxpayers claiming the section 45Q tax credit, and rules regarding adequate security measures for "secure geological storage of CO_2."

Following publication of today's final Class VI requirements, and as clarified in the guidance, taxpayers claiming the section 45Q tax credit must follow the appropriate UIC requirements (*e.g.,* Class II or Class VI). The guidance also clarifies that taxpayers claiming section 45Q tax credit must follow the GS monitoring, reporting, and verification procedures finalized in the CO_2 Injection and GS Reporting Rule that is part of the GHG Reporting Program.

General Accountability Office Reports on GS and CCS: The United States General Accountability Office (GAO) has prepared, or is in the process of preparing, several reports for Congressional requestors related to the GS of CO_2. In September 2008, GAO (GAO–08–1080) completed a report related to assessing the application of CCS technologies entitled: *Climate Change—Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage as a Key Mitigation Option* (GAO, 2008). In September 2010, GAO released a report entitled: *Climate Change, A Coordinated Strategy Could Focus Federal Geoengineering Research and Inform Governance Efforts* (GAO–10–903) which describes innovative technologies that may alter climate change, details current research activities, and clarifies how coordination could inform subsequent climate science efforts. GAO initiated another report (GAO–10–675) focused on the methods by which coal-fired power plants may capture carbon emissions. The draft title of that study is: *Coal Power Plants—Opportunities Exist for DOE to Provide Better Information on the Maturity of Key Technologies to Reduce Carbon Emissions* (GAO, 2010).

EPA will continue to coordinate internally and with other Federal agencies to promote consistency in existing and future GS and CCS initiatives.

E. What steps did EPA take to develop this rulemaking?

Today's final rule builds upon longstanding programmatic requirements for underground injection that have been in place since the 1980s and that are used to manage over 800,000 injection wells nationwide. These programmatic requirements are designed to prevent fluid movement into USDWs by addressing the potential pathways through which injected fluids can migrate into USDWs and cause endangerment.

EPA coordinated with Federal and non-Federal entities on GS and CCS to determine how best to tailor existing UIC requirements to CO_2 for GS.

EPA has taken a number of steps in advance of today's action including: (1) Developing guidance for experimental GS projects; (2) conducting research; (3) conducting stakeholder coordination and outreach; (4) issuing a proposed rulemaking and soliciting and reviewing public comment; and, (5) publishing a Notice of Data Availability (NODA) and Request for Comment to seek additional input on the rulemaking.

1. Developing Guidance for Experimental GS Projects

In 2007, EPA issued technical guidance to assist State and EPA Regional UIC programs in processing permit applications for pilot and other small scale experimental GS projects. The guidance was developed in cooperation with DOE and States, the Ground Water Protection Council (GWPC), the Interstate Oil and Gas Compact Commission (IOGCC), and other stakeholders. *UIC Program Guidance #83: Using the Class V Experimental Technology Well Classification for Pilot Carbon GS Projects* (USEPA, 2007) provides recommendations for permit writers regarding the use of the UIC Class V experimental technology well classification at demonstration GS projects while ensuring USDW protection. Program guidance #83 is available at: *http://www.epa.gov/safewater/uic/wells_sequestration.html.* EPA is preparing additional guidance for owners or operators and Directors regarding the use of Class V experimental technology wells for GS following promulgation of today's rule.

2. Conducting Research

EPA participated in and supported research to inform today's rulemaking including: Supporting and tracking the development and results of national and international CO_2 GS field and research projects; tracking GS-related State regulatory and legislative efforts; and conducting technical workshops on issues associated with CO_2 GS. EPA described these research activities in detail in the proposed rule (July 2008) and the NODA and Request for Comment (August 2009). Additional information pertaining to these activities, which are summarized below, may be found in the rulemaking docket.

a. Tracking the Results of CO_2 GS Research Projects

To inform today's rulemaking, EPA tracked the progress and results of national and international GS research projects. DOE leads field research on GS in the U.S. in conjunction with the Regional Carbon Sequestration Partnerships (RCSPs). Currently, DOE's NETL is developing and/or operating GS projects, a number of which have either completed injection or are in the process of injecting CO_2. The seven RCSPs are conducting pilot and demonstration projects to study site characterization (including injection and confining formation information, core data and site selection information); well construction (well depth, construction materials, and proximity to USDWs); frequency and types of tests and monitoring conducted (on the well and on the project site); modeling and monitoring results; and injection operation (injection rates, pressures, and volumes, CO_2 source and co-injectates). See section II.E.5 for more information on the status of these projects.

Lawrence Berkeley National Laboratory (LBNL) research: EPA and DOE are jointly funding work by the LBNL to study potential impacts of CO_2 injection on ground water aquifers and drinking water sources. The preliminary results have been used to inform today's rulemaking and are described in detail in section II.E.5.

In addition, EPA is funding an analysis by LBNL to integrate experimental and modeling information. LBNL will characterize ground water samples and aquifer mineralogies from select sites in the U.S. and conduct controlled laboratory experiments to assess the potential mobilization of hazardous constituents by dissolved CO_2. These experiments will provide data that will be used to validate previous predictive modeling studies (of aquifer vulnerabilities to potential CO_2 leaks) which may be applied to other GS sites in the future to assess the fate and migration of CO_2-mobilized constituents in ground water.

EPA's Office of Research and Development (ORD) GS research: EPA's ORD engages Agency scientists and engineers in targeted research to provide information to stakeholders and policy makers focused on areas of national environmental concern, including climate change and GS. In addition, ORD's National Center for Environmental Research (NCER) provides extramural research grants for similar investigations through a competitive solicitation process. In the fall of 2009, NCER awarded six Science To Achieve Results (STAR) grants to recipients from major universities and institutions. The awards were granted to projects focused on *Integrated Design, Modeling and Monitoring of GS of Anthropogenic CO_4 to Safeguard Sources of Drinking Water.* Work under the grants began in late 2009 and includes: Evaluating potential impacts on drinking water aquifers of CO_2-rich dissolved brines (Clemson University); reducing the hydrologic and geochemical uncertainties associated with CO_2 sequestration in deep, saline reservoirs (University of Illinois-Urbana); assessing appropriate monitoring approaches at GS sites (University of Texas at Austin); integrating design, monitoring, and modeling of GS to assist in developing a practical methodology for characterizing risks to USDWs (University of Utah); conducting laboratory experiments on shallow aquifer systems to improve our understanding of geochemical and microbiological reactions under low pH/high CO_2 stress (Columbia University); and, developing a set of computational tools to model CO_2 and brine movement associated with GS (Princeton University).

International projects: EPA is tracking the progress of international GS efforts. The largest and longest-running commercial, large-scale projects in operation today include: The Sleipner Project in the Norwegian North Sea (operating since 1996); the Weyburn enhanced oil recovery (EOR) project in Saskatchewan, Canada (operating since 2000); the In Salah Gas Project in Algeria (operating since 2004); and Snohvit, also in offshore Norway in the Barents Sea (operating since 2008). Other projects EPA is tracking include Otway in Australia (operating since 2008); Ketzin in Germany (operating since 2008); and Lacq in France (operating since 2009). EPA is also tracking two projects that are anticipated to begin injection in the near future: CarbFix in Iceland (anticipated to commence injection in 2010) and Gorgon in Australia (anticipated to start in 2014). EPA evaluated available information and experiences gained from these international projects to inform today's action, as appropriate. Additional information on how these and other international projects informed the GS rulemaking is contained in the rulemaking docket (USEPA, 2010a).

b. Tracking State Regulatory Efforts

EPA has made it a priority to engage States and State organizations throughout the rulemaking effort. EPA recognizes the complexity and importance of the States' approaches to managing GS and is aware that States are in various stages of developing statutory frameworks, regulations, technical guidance, and strategies for addressing CCS and GS. Throughout the regulatory development process for the Class VI regulation, EPA monitored States' regulatory efforts and approaches and sought input on State activities related to addressing GS in the proposed rule and NODA. At present, several States have published GS regulations, while others are investigating and developing strategies to address GS issues (*e.g.,* management of multi-purpose injection wells in oil and gas reservoirs). EPA is tracking regulatory efforts in 18 States: Colorado, Illinois, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia, and Wyoming. EPA is considering this information as it develops guidance on the primacy application and approval process for Class VI wells. Information about these State activities may be found in the docket for today's rulemaking.

c. Conducting Technical Workshops on Issues Associated With CO_2 GS

EPA conducted a series of technical workshops with regulators, industry, utilities, and technical experts to identify and discuss questions relevant to the effective management of CO_2 GS. The workshops included the following: Measurement, Monitoring, and Verification (in New Orleans, Louisiana on January 16, 2008); Geological Setting and AoR Considerations for CO_2 GS (in Washington, DC on July 10–11, 2007); Well Construction and MIT (in Albuquerque, New Mexico on March 14, 2007); a State Regulators' Workshop on GS of CO_2 (in collaboration with DOE in San Antonio, Texas on January 24, 2007); an International Symposium on Site Characterization for CO_2 Geological Storage (co-sponsored with LBNL in Berkeley, California on March 20–22, 2006); Risk Assessment for Geologic CO_2 Storage (co-sponsored with the Ground Water Protection Council (GWPC) in Portland, Oregon on September 28–29, 2005); and Modeling and Reservoir Simulation for Geologic Carbon Storage (in Houston, Texas on April 6–7, 2005). Summaries of these workshops are available on EPA's Web site, at *http://www.epa.gov/safewater/uic/wells_sequestration.html.*

3. Conducting Stakeholder Coordination and Outreach

Throughout the rulemaking process, the Agency conducted public workshops and public hearings and consulted with specific groups. EPA representatives also attended meetings to explain the GS rulemaking effort to interested members of the public and stakeholder groups. Meeting information, notes, and summaries are available in the docket for this rulemaking.

Public stakeholder coordination: EPA held public meetings to discuss EPA's rulemaking approach, and consulted with other stakeholder groups including non-governmental organizations (NGOs) to gain an understanding of stakeholder interests and concerns. As part of this outreach, EPA conducted two public stakeholder workshops with participants from industry, environmental groups, utilities, academia, States, and the general public. These workshops were held in December 2007 and February 2008. Workshop summaries are available on EPA's Web site, at *http://www.epa.gov/safewater/uic/wells_sequestration.html.*

EPA also coordinated with GWPC, a State association that focuses on ensuring safe application of injection well technology and protecting ground water resources, and IOGCC, a chartered State association representing oil and gas producing States throughout the rulemaking process. Members of GWPC and IOGCC have specific expertise regulating the injection of CO_2 for the ER of oil and gas. EPA staff attended national meetings and calls of these organizations, as well as those held by technical and trade organizations, NGOs, States, and Tribal organizations to discuss the rulemaking process and GS-specific technical issues.

Consultation with the National Drinking Water Advisory Council (NDWAC): In November 2008, during the public comment period for the proposed rule, EPA met with NDWAC to discuss the proposed rule. At the meeting, EPA presented information about the rulemaking and responded to NDWAC questions and comments. NDWAC members indicated that they understood the role of GS as a climate mitigation tool and encouraged the Agency to continue to ensure the protection of USDWs. Since proposal publication, EPA has met with NDWAC to discuss the status of the rule and answer questions from NDWAC members. The notes of these meetings are in the rulemaking docket.

Consultations with States, Tribes, and Territories: EPA engaged States, Tribes, and Territories early and throughout the rulemaking process to promote open communication and solicit input and feedback on all aspects of the rule.

In April of 2008, prior to publication of the proposed rule, the Agency sent background information about the rulemaking to all Federally-recognized Indian Tribes and invited participation in a dedicated GS consultation effort. EPA Regional Indian Coordinators (RICs), the National Indian Workgroup (NIWG), the National Tribal Caucus (NTC) and the National Tribal Water Council (NTWC) contacts were also invited to participate in the consultation. EPA provided additional rulemaking updates after publication of the proposal with the above-mentioned groups as well as the National Water Program State-Tribal Climate Change Council (STC3). The Fort Peck Assiniboine and Sioux Tribes and the Navajo Nation received UIC program primacy for the Class II program (under section 1425 of the SDWA) during the proposal period for this rule (73 FR 65556; 73 FR 63639). Therefore, the Agency initiated an additional consultation effort with these Tribal co-regulators post-proposal. Summaries of the Tribal consultation conference calls are included in the docket for today's rulemaking.

To ensure that States were consulted, the Agency also sent background information about the rulemaking to States and State organizations including the National Governors' Association, National Conference of State Legislatures, Council of State Governments, and the National League of Cities, among others, and held a dedicated conference call on GS for interested State representatives in April 2008. Additionally, the Agency participated in rulemaking updates, as appropriate, during national meetings and conferences, and gave presentations to State organizations throughout development of the rule. A summary of these efforts is included in the docket for today's rulemaking.

Consultation with the United States Department of Health and Human Services (HHS): Pursuant to SDWA section 1421, EPA consulted with the U.S. Department of Health and Human Services during the rulemaking process. Prior to proposal publication and rule finalization, the Agency provided background information to HHS on the purpose and scope of the rule. In June of 2010, EPA met with HHS to discuss the GS rulemaking process as well as key elements of the proposed rule, the Notice of Data Availability and Request for Comment, and the final rule. During the June 2010 briefing, HHS participants asked about technical criteria for Class VI wells and monitoring technologies applicable to GS projects. The Agency addressed questions and comments and HHS certified that the EPA satisfied consultation obligations under the SDWA. The memo certifying this consultation is available in the docket for today's rulemaking.

4. Proposed Rulemaking

On July 25, 2008, EPA published the proposed *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells* (73 FR 43492). The Agency proposed a new class of injection well (Class VI), along with technical criteria for permitting Class VI wells that tailored the existing UIC regulatory framework to address the unique nature of CO_2 injection for GS, including:

- Site characterization requirements that would apply to owners or operators of Class VI wells and require submission of extensive geologic, hydrogeologic, and geomechanical information on the proposed GS site to ensure that Class VI wells are located in suitable formations. EPA also proposed that owners or operators identify additional containment/confining zones, if required by the Director, to improve USDW protection.
- Enhanced AoR and corrective action requirements (*e.g.,* plugging abandoned wells) to delineate the AoR for GS projects using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream. EPA also proposed that owners or operators periodically reevaluate the AoR around the injection well to incorporate monitoring and operational data and verify that the CO_2 is moving as predicted within the subsurface.
- Well construction using materials that are compatible with and can withstand contact with CO_2 over the life of the GS project.
- Multi-faceted monitoring of the CO_2 stream, injection pressures, the integrity of the injection well, groundwater quality above the confining zone(s), and the position of the CO_2 plume and the pressure front throughout injection.
- Comprehensive post-injection monitoring and site care until it can be demonstrated that movement of the plume and pressure front have ceased and the injectate does not pose a risk to USDWs.
- Financial responsibility requirements to ensure that financial resources would be available for corrective action, injection well plugging, post-injection site care, and site closure, and emergency and remedial response.

Following publication of the proposed rule, EPA initiated a 120-day public comment period, which the Agency extended by 30 days to accommodate requests from interested parties. The public comment period for the proposed rule closed on December 24, 2008. EPA received approximately 400 unique submittals from 190 commenters, including late submissions. Commenters represented States; industry (including the oil and gas industry, electric utilities, and energy companies); environmental groups; and associations (including water organizations and CCS associations).

During the public comment period, the Agency held public hearings on the proposed rule in Chicago, IL on September 30, 2008 and in Denver, CO on October 2, 2008. The two hearings collectively drew approximately 100 people representing non-governmental organizations, academia, industry, and other organizations. At the hearings, 29 people submitted oral comments. Transcripts of the public hearings are in the rulemaking docket (Docket ID Nos. EPA–HQ–OW–2008–0390–0185 and EPA–HQ–OW–2008–0390–0256).

5. Notice of Data Availability and Request for Comment

Based on public comments received on the proposed rule, the Agency identified several topics on which it needed additional public comment. EPA published *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Notice of Data Availability and Request for Comment* (74 FR 44802) on August 31, 2009, to describe additional topics and request comment.

The NODA and Request for Comment presented new data and information from three DOE-sponsored RCSP projects including: (1) The Escatawpa, Mississippi project; (2) the Aneth Field, Paradox Basin project in Southeast Utah; and, (3) the Pump Canyon Site project in New Mexico. Additional information on these projects and responses to comments received on the NODA and Request for Comment are available in the docket for this rulemaking.

The NODA and Request for Comment also provided results of two GS-related modeling studies conducted by the LBNL. The first study (Birkholzer *et al.,* 2008a) focused on the potential for GS to cause changes in ground water quality as a result of potential CO_2 leakage and subsequent mobilization of trace elements such as arsenic, barium, cadmium, mercury, lead, antimony, selenium, zinc, and uranium. Results from this model simulation suggest that if CO_2 were to leak into a shallow aquifer, mobilization of lead and arsenic could occur, causing increases in the concentration of these trace elements in ground water and potential for drinking water standard exceedances.

The second study modeled a theoretical scenario of GS in a sedimentary basin to demonstrate the potential for basin-scale hydrologic impacts of CO_2 storage (Birkholzer *et al.,* 2008b). Model results indicate that basin-wide pressure influences may be large and that predicted pressure changes could move saline water upward into overlying aquifers if localized pathways, such as conductive faults, are present. This example illustrates the importance of basin-scale evaluation of reservoir pressures and far-field pressures resulting from CO_2 injection.

Additional information on LBNL's research and responses to comments received on the NODA and Request for Comment are available in the docket for this rulemaking.

The full publications on the LBNL research are also available on LBNL's Web site at *http://esd.lbl.gov/GCS/projects/CO2/index_CO2.html.*

Lastly, the NODA and Request for Comment presented an alternative to address public comments and concerns about the proposed injection depth requirements for Class VI wells. Section III.D of today's action contains more information on this subject.

Following publication of the NODA and Request for Comment, EPA initiated a 45-day public comment period, which closed on October 15, 2009. EPA received 67 unique submittals from 64 commenters, many of whom commented on the proposed rule. The Agency also held a public hearing in Chicago, IL on September 17, 2009. Six people, representing the oil and gas industry, electric utilities, water associations, and academia attended the hearing. Two attendees submitted oral comments at the hearing. A transcript of the public hearing is in the rulemaking docket (EPA–HQ–OW–2008–0390–391).

F. How will EPA's adaptive rulemaking approach incorporate future information and research?

In the preamble to the proposed rule (73 FR 43492), EPA explained the need for and merits of using an adaptive approach to regulating injection of CO_2 for GS at 40 CFR parts 144 through 146. The Agency indicated that this approach would provide regulatory certainty to owners or operators, promote consistent permitting approaches, and ensure that Class VI permitting Agencies are able to meet current and future demand for Class VI permits. The proposal also clarified that, as the Agency reviewed public comments, it would continue to evaluate ongoing research and demonstration projects and gather other relevant information as needed to make refinements to the rulemaking process.

Many commenters strongly supported an adaptive, flexible approach and suggested that the Agency initially take a conservative approach in developing the UIC–GS requirements, with a provision for periodic review of the rule to allow EPA to incorporate operational experience as it is gained. These commenters also urged EPA not to wait until the completion of DOE's pilot projects before finalizing the GS rule, expressing a need for early regulatory certainty.

Some commenters expressed concerns about an adaptive approach, stating that it could lead to regulatory uncertainty because modifications could be made after the initial regulations are promulgated. One commenter said that GS will not scale-up rapidly, leaving ample time to study and assess possible regulatory approaches.

EPA agrees with commenters who supported an adaptive approach to the UIC rulemaking for GS. Additionally, the Agency believes that there is a need to have regulations in place during the earliest phases of GS deployment. Finalizing today's requirements will allow early Class VI wells to be permitted in a manner that addresses the unique characteristics of CO_2 injection for GS and allow early projects to demonstrate successful confinement of CO_2 in a manner that is protective of USDWs. EPA also believes that an adaptive approach enables the Agency to make changes to the program as necessary to incorporate new research, data, and information about GS and associated technologies (*e.g.,* modeling and well construction). This new information may increase protectiveness, streamline implementation, reduce costs, or otherwise inform the requirements for GS injection of CO_2. The Agency plans, every six years, to review the rulemaking and data on GS projects to determine whether the appropriate amount and types of information and appropriate documentation are being collected, and to determine if modifications to the Class VI UIC requirements are appropriate or necessary. This time period is consistent with the periodic review of National Primary Drinking Water Standards under Section 1412 of SDWA.

G. How does this action affect UIC program implementation?

Under section 1421(b), the SDWA mandates that EPA develop minimum Federal requirements for State UIC primary enforcement responsibility, or primacy, to ensure protection of USDWs. In order to implement the UIC program, States must apply to EPA for primacy approval. In the primacy application, States must demonstrate: (1) State jurisdiction over underground injection projects; (2) that their State regulations are at least as stringent as those promulgated by EPA (*e.g.,* permitting, inspection, operation, monitoring, and recordkeeping requirements); and (3) that the State has the necessary administrative, civil, and criminal enforcement penalty remedies pursuant to 40 CFR 145.13 authorities.

Once an application for primacy is received, the EPA Administrator must review and approve or disapprove the State's primacy application. EPA may also choose to approve or disapprove part of the application. This determination is based on EPA's mandate under the SDWA as implemented by UIC regulations established in 40 CFR part 144 through 146, and must be made by a rulemaking. Most States were authorized with full or partial primacy for the UIC program in the early 1980s; recently, two Tribes received primacy for the Class II program under section 1425 of the SDWA. EPA directly implements the UIC program in States that have not applied for primacy and States that have primacy for part of the UIC program. A complete list of the primacy agencies in each State is available at *http://www.epa.gov/safewater/uic/primacy.html.*

EPA may approve primacy for States as authorized by sections 1422 and 1425 of the SDWA. There are fundamental differences between how these two statutory provisions are applied. Under section 1422, States must demonstrate that their proposed UIC program meets the statutory requirements under section 1421 and that their program contains requirements that are at least as stringent as the minimum Federal requirements provided for in the UIC regulations to ensure protection of USDWs. Alternatively, States seeking primacy under section 1425 have the option to demonstrate that their Class II program is an "effective" program to prevent underground injection that endangers USDWs. Typically, these States follow the broader elements of a State program submission established by EPA in 40 CFR part 145, subpart C. In today's final rule, and in accordance with the SDWA section 1422, all Class VI State programs must be at least as stringent as the minimum Federal requirements finalized in today's rule.

UIC program implementation: Authority to administer a State UIC program may be granted to one or more State agencies. States may choose to include in their UIC primacy application a program that is administered by multiple agencies. Under 40 CFR 145.23, in order for more than one agency to be responsible for administration of the program, each agency must have Statewide jurisdiction over the class of injection activities for which they are responsible. Some States administer their program for all injection well classes through a single agency, whereas other States elect to divide the program between agencies. For example, in most States, the Class II program is run by an oil and gas agency and other well classes are run by a State environmental agency (*e.g.,* the Oklahoma Corporation Commission oversees Class II wells in the State, and the Oklahoma Department of Environmental Quality oversees other well classes). Additionally, several States allow their oil and gas agencies to administer their UIC program for specific well classes or subclasses provided they meet all minimum Federal requirements (*e.g.,* the Railroad Commission of Texas oversees Class III brine-mining wells and Class V geothermal wells in Texas). EPA believes that retaining this flexibility for States to identify the appropriate agency to oversee Class VI wells will address commenters' concerns that States should be afforded the opportunity to determine which agency should oversee Class VI wells, and recognizes the existing expertise of both State oil and gas agencies and deep well injection programs, generally overseen by State environmental agencies.

Proposed approach for Class VI primacy and public comment: In the proposed rule, EPA emphasized that States, Territories, and Tribes seeking primacy for Class VI wells would be required to demonstrate that their regulations are at least as stringent as the proposed minimum Federal requirements. Recognizing that some States may wish to obtain primacy for only Class VI wells, the Agency requested comment on the merits and possible disadvantages of allowing primacy approval for Class VI wells independent of other well classes.

Commenters representing States, industry, various trade associations, and electric utilities supported the concept of allowing independent primacy for Class VI wells. Commenters asserted that States have the best knowledge of regional geology and areas in need of special protection, along with necessary pre-existing relationships with the regulated community. Commenters also agreed with EPA's statement in the proposal that independent primacy would encourage States to develop a comprehensive regulatory program for all aspects of CCS (noting that some States have already begun legislative efforts that are wider in scope than the proposed Federal rule) and facilitate the rapid deployment of commercial-scale CCS projects. They also asserted that this approach is acceptable under the UIC program's statutory authority.

Independent primacy for Class VI wells: Historically, EPA has not accepted independent UIC primacy applications from States for individual well classes under section 1422 of SDWA, as a matter of policy. For example, if a State wanted primacy for Class I wells, the State would also need to accept primacy for all other well classes under section 1422 of SDWA (See section II.H for a description of well classifications). This policy has been in place since the initiation of the Federal UIC program and was intended to encourage States to take full primacy for UIC programs, avoid Federal duplication of efforts, and provide for administrative efficiencies.

However, based on comments on the UIC–GS proposed rule and discussions with States and stakeholders, the Agency will allow independent primacy for Class VI wells under § 145.1(i) of today's rule, and will accept applications from States for independent primacy under section 1422 of the SDWA for managing UIC–GS projects under Class VI. EPA believes that States are in the best position to implement UIC–GS programs, and by allowing for independent Class VI primacy, EPA encourages States to take responsibility for implementation of Class VI regulations. The Agency's UIC program believes that this may, in turn, help provide for a more comprehensive approach to managing GS projects by promoting the integration of GS activities under SDWA into a broader framework for States managing issues related to CCS that may lie outside the scope of the UIC program or other EPA programs. This would harness the unique efficiencies States can offer to promote adoption of GS technology that incorporates issues in the broader scope of CCS, while ensuring that USDWs are protected through the UIC regulatory framework. Allowing States to apply only for Class VI primacy will also shorten the primacy approval process.

EPA's willingness to accept independent primacy applications for Class VI wells applies only to Class VI well primacy and does not apply to any other well class under SDWA section 1422 (*i.e.,* I, III, IV, and V). EPA believes that this shift in its longstanding policy of discouraging "partial" or "independent" primacy is warranted to encourage States to seek primacy for Class VI wells and allow States to address the unique challenges that would otherwise be barriers to comprehensive and seamless management of GS projects.

The Agency recognizes that some States are currently addressing off-facility surface access for corrective action and monitoring, pore space ownership and trespass issues, and amalgamation of correlative rights in depleted reservoirs for GS. Additionally, because GS technologies are an important component of CCS, the Agency considers the allowance for independent Class VI primacy important and unique to this well class. This decision is expected to ensure that the Class VI primacy application process does not serve as a barrier to GS and CCS deployment. EPA will not consider applications for independent primacy for any other injection well class under SDWA section 1422 other than Class VI, nor will the Agency accept the return of portions of existing 1422 programs. EPA will continue to process primacy applications for Class II injection wells under the authority of section 1425 of the SDWA.

Today's final rule includes a new subparagraph § 145.1(i) that establishes EPA's intention to allow for independent primacy for Class VI wells. The Agency is developing implementation materials to provide guidance to States applying for Class VI primacy under section 1422 of SDWA and to assist UIC Directors evaluating permit applications.

Effective date of the GS rule and Class VI primacy application and approval timeframe: Today's rule, at § 145.21(h), establishes a Federal Class VI primacy program in States that choose not to seek primacy for the Class VI portion of the UIC program within the approval timeframe established under section 1422(b)(1)(B) of the SDWA. Under § 145.21(h), States will have 270 days following final promulgation of the GS rule September 6, 2011 to submit a complete primacy application that meets the requirements of §§ 145.22 or 145.32. Pursuant to the SDWA, this 270-day timeframe allows States that seek primacy for the new Class VI wells a reasonable amount of time to develop and submit their application to EPA for approval. EPA will assist States in meeting the 270-day deadline by developing implementation materials for States and conducting training on the process of applying for and receiving primacy for Class VI wells under section 1422 of SDWA. EPA will also assist States as they develop GS regulations that are the equivalent of minimum Federal requirements and plans to use an expedited process for approving primacy.

Although the SDWA allows the Administrator to extend the date for submission of an application for up to 270 additional days for good cause, the Agency has determined that it will not provide for an extension for States applying for Class VI primacy. Instead, EPA believes that, in light of national priorities for promoting climate change mitigation strategies and Administration priorities for developing and deploying CCS projects in the next few years, it is important to have enforceable Class VI regulations in place nationwide as soon as possible.

If a State does not submit a complete application during the 270-day period, or EPA has not approved a State's Class VI program submission, then EPA will establish a Federal UIC Class VI program in that State after the 270-day application period closes. This will ensure that tailored State- or Federally-enforceable requirements applicable to GS projects will be in place nationwide as soon as possible after rule finalization. Further, a clear, nationally-consistent deadline will avoid potential confusion that may arise if some States have approved Class VI programs and others do not. EPA will publish a list of the States where the Federal Class VI requirements have become applicable in the **Federal Register** and update 40 CFR part 147. It is important to note that, although the Agency is not accepting extension requests, a State may, at any time in the future, apply for primacy for the new GS requirements following establishment of a Federal Class VI UIC program. If a State receives approval after the 270-day deadline (for a primacy application submitted either before or after the deadline), EPA will publish a subsequent notice of the approval as required by the SDWA; at that point, the State, rather than EPA, will implement the Class VI program.

The Agency clarifies that States may not issue Class VI UIC permits until their Class VI UIC programs are approved. During the first 270-days and prior to EPA approval of a Class VI primacy application, States without existing SDWA section 1422 primacy programs must direct all Class VI GS permit applications to the appropriate EPA Region. EPA Regions will issue permits using existing authorities and well classifications (*e.g.,* Class I or Class V), as appropriate.

States with existing UIC primacy for all non-Class VI well classes under section 1422 that receive Class VI permit applications within the first 270 days after promulgation of the final rule may consider using existing authorities (*e.g.,* Class I or Class V), as appropriate, to issue permits for CO_2 injection for GS while EPA is evaluating their Class VI primacy application. EPA encourages States to issue permits that meet the requirements for Class VI wells to ensure that Class V and Class I wells previously used for GS can be re-permitted as Class VI wells that meet the protective requirements of today's final rule within one year of promulgation of the Class VI regulation, pursuant to requirements at § 146.81(c), with minimal additional effort on the part of the owner or operator or the Director.

After the 270-day deadline, and until a State has an approved Class VI program, EPA will establish and implement a Class VI program. Therefore, all permit applications in States without Class VI programs must be directed to the appropriate EPA Region in order for a Class VI permit to be issued. In States where EPA directly implements the Class VI program, Class I permits for CO_2 injection for GS may no longer be issued and Class V permits may only be issued to projects eligible for such permits (see discussion of the relationship between Class V and Class VI permits in Section II.H).

Streamlining the primacy approval process: In an effort to support States with the Class VI primacy application process and respond to comments received during the rulemaking process, today's rule includes new regulatory language at §§ 145.22 and 145.23 to streamline and clarify the process for submission of Class VI primacy applications and address the unique aspect of Class VI injection operations. For example, EPA is allowing the electronic submission of required primacy application information (*e.g.,* letter from the Governor, program description, Attorney General's statement, or Memorandum of Agreement). The Agency is also allowing the use of existing reporting form(s), *e.g.,* existing UIC program forms or State equivalents, for Class VI wells, as appropriate.

EPA will evaluate the efficiency and effectiveness of electronic submittals as part of the adaptive approach to the GS rulemaking and determine whether electronic submittal may be applicable to other UIC primacy applications submitted to EPA for review and approval under sections 1422 and 1425 of SDWA. Additionally, the Agency is developing a Class VI Program Primacy Application and Implementation Manual that describes, for States, the process of applying for and receiving primacy for Class VI wells under section 1422 of SDWA. The Manual will also provide tools designed to assist States with the development of their primacy application and UIC Directors with evaluating permit application information.

Unique requirements for Class VI permit applications: To address the unique nature of Class VI injection operations, today's rule at § 145.23(f) includes new language describing the requirements for Class VI State program descriptions. Specifically, § 145.23(f)(1) requires States to include a schedule for issuing Class VI permits for wells within the State that require them within two years after receiving program approval from EPA, and § 145.23(f)(2) requires States to include their permitting priorities, as well as the number of permits to be issued during the first two years of program operation. In addition, today's rule at § 145.23(f)(4) requires the Director of Class VI programs approved before December 10, 2011, to provide a description of the process for notifying owners or operators of any Class I wells previously permitted for the purpose of geologic sequestration or Class V experimental technology wells no longer being used for experimental purposes that will continue injection of carbon dioxide for the purpose of GS that they must apply for a Class VI permit pursuant to requirements at § 146.81(c) within one year of December 10, 2011. § 145.23(f)(4) also requires the Director of a Class VI Program approved after December 10, 2011, to provide a description of the process for notifying owners or operators of any Class I wells previously permitted for the purpose of geologic sequestration or Class V experimental technology wells no longer being used for experimental purposes that will continue injection of carbon dioxide for the purpose of GS or Class VI wells permitted by EPA that they must apply to the State program for a Class VI permit pursuant to requirements at § 146.81(c) within one year of Class VI program approval. EPA is committed to working closely with and receiving input from States during all stages of the GS permitting process, irrespective of primacy status. Close coordination during program implementation will minimize effort and burden on States and owners and operators and streamline the administrative process for transferring permits or permit applications when primacy is granted. These requirements are tailored for Class VI wells to ensure that States are prepared to review Class VI permit applications as soon as possible following program approval; and, in light of the national priorities to promote climate change mitigation strategies, such modifications of § 145.23 may help ensure expeditious implementation of Class VI requirements across the country.

Today's rule, at § 145.23(f)(13), requires States to describe in their primacy application procedures for notifying any States, Tribes, and Territories of Class VI permit applications where the AoR is predicted to cross jurisdictional boundaries and for documenting this consultation. This new requirement addresses comments on the proposed rule and NODA and Request for Comment that Class VI operations are likely to have larger AoRs that may cross jurisdictional boundaries and necessitate trans-boundary coordination. At § 145.23(f)(9), the final rule also requires States receiving Class VI program approval to incorporate information related to any EPA approved exemptions expanding the areal extent of an existing Class II EOR/EGR aquifer exemption for Class VI injection. This requirement complements aquifer exemption requirements promulgated under today's rule and ensures that State programs incorporate information regarding the specific location (and any associated supporting data) into their program descriptions.

The Agency plans to review these requirements as part of the adaptive rulemaking approach to ensure that the tailored requirements are appropriate to ensure USDW protection from endangerment.

H. How does this rule affect existing injection wells under the UIC program?

Today's rulemaking establishes a new class of injection well, Class VI, for GS projects because CO_2 injection for long-term storage presents several unique challenges that warrant the designation of a new well type.

When EPA initially promulgated its UIC regulations in 1980, the Agency defined five classes of injection wells at 40 CFR 144.6, based on similarities in the fluids injected, construction, injection depth, design, injection practices, and operating techniques. These five well classes are still in use today and are described below.

- Class I wells inject industrial non-hazardous liquids, municipal wastewaters, or hazardous wastes beneath the lowermost USDW. These wells are among the deepest of the injection wells and are subject to technically sophisticated construction and operation requirements.
- Class II wells inject fluids (*e.g.,* CO_2; brine) in connection with conventional

oil or natural gas production, enhanced oil and gas production, and the storage of hydrocarbons that are liquid at standard temperature and pressure.

- Class III wells inject fluids associated with the extraction of minerals, including the mining of sulfur and solution mining of minerals (*e.g.,* uranium).
- Class IV wells inject hazardous or radioactive wastes into or above USDWs. Few Class IV wells are in use today. These wells are banned unless authorized under a Federal or State-approved ground water remediation project.
- Class V includes all injection wells that are not included in Classes I–IV. In general, Class V wells inject non-hazardous fluids into or above USDWs; however, there are some deep Class V wells that are used to inject below USDWs. This well class includes Class V experimental technology wells including those permitted as GS pilot projects.

The Agency acknowledges that owners or operators of wells regulated under existing well classifications may want to change the purpose of their injection activity. The following sections describe the applicability of today's rule to owners or operators of existing wells and considerations for Directors evaluating existing wells that may be re-permitted as Class VI wells.

Class I wells: Wells previously permitted as Class I wells for GS, including wells permitted prior to rule promulgation and wells permitted during the 270-day period after rule promulgation, must apply for Class VI permits within one year of promulgation by December 10, 2011, pursuant to requirements at § 146.81(c). The Agency anticipates that permit applications (*e.g.,* Class I or Class V) developed for CO_2 GS following publication of today's rule will follow the Class VI requirements and be designed to facilitate efficient re-permitting as Class VI wells. Such forethought will allow new Class VI permits to be issued with minimal additional effort on the part of the owner or operator and the Director. Additional information on Class V experimental technology wells is discussed in this section. For additional information on permitting authorities and UIC program implementation, see section II.G.

Class II CO_2 injection wells designated for enhanced recovery: Enhanced oil recovery (EOR) and enhanced gas recovery (EGR) technologies, collectively referred to as enhanced recovery (ER), are used in oil and gas reservoirs to increase production. Injection of CO_2 is one of several ER techniques that have successfully been used to boost production efficiency of oil and gas by re-pressurizing the reservoir, and in the case of oil, by also increasing mobility. Injection wells used for ER are regulated through the UIC Class II program.

CO_2 currently injected for ER in the U.S. comes from both natural and anthropogenic sources, which provide 79 percent and 21 percent, respectively, of CO_2 supply (DOE NETL, 2008). Natural CO_2 sources consist of geologic domes in Colorado, New Mexico, and Mississippi. Anthropogenic sources of CO_2 supplied for ER today include natural gas processing, ammonia and fertilizer production, and coal gasification facilities.

Historically, CO_2 purchases comprise about 33 to 68 percent of the cost of a CO_2-ER project (EPRI, 1999). For this reason, CO_2 injection volumes are carefully tracked at ER sites. CO_2 recovered from production wells during ER is recycled (*i.e.,* separated and re-injected), and at the conclusion of an ER project as much CO_2 as is feasible is recovered and transported to other ER facilities for re-use. However, a certain amount of CO_2 remains underground. Current Class II ER requirements do not require tracking and monitoring of the injectate; therefore, the migration and fate of the unrecovered CO_2 is not documented.

As of 2008, there were 105 CO_2-EOR projects within the US (Oil and Gas Journal, 2008). The majority (58) 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. CO_2-EOR projects recovered 323,000 barrels of oil per day in 2008, 6.5 percent of total domestic oil production. A total of 6,121 CO_2 injection wells among 105 projects were used to inject 51 million metric tons of CO_2 (Oil and Gas Journal, 2008; EIA, 2009; DOE NETL, 2008). Compared to CO_2-EOR, CO_2-EGR remains largely in the development stage (*e.g.,* Oldenburg *et al.,* 2001).

Future deployment of CCS may fundamentally alter CO_2-ER in the U.S. DOE anticipates that many early GS projects will be sited in depleted or active oil and gas reservoirs because the reservoirs have been previously characterized for hydrocarbon recovery and may have suitable infrastructure (*e.g.,* wells, pipelines, etc.) in place. Additionally, oil and gas fields now considered to be "depleted" may resume operation because of increased availability and decreased cost of anthropogenic CO_2.

EPA believes that if the business model for ER changes to focus on maximizing CO_2 injection volumes and permanent storage, then the risk of endangerment to USDWs is likely to increase. This is because reservoir pressure within the injection zone will increase as CO_2 injection volumes increase. Elevated reservoir pressure is a significant risk driver at GS sites, as it may cause unintended fluid movement and leakage into USDWs that may cause endangerment. Additionally, increasing reservoir pressure within the injection zone as a result of GS will stress the primary confining zone (*i.e.,* geologic caprock) and well plugs to a greater degree than during traditional ER (*e.g.,* Klusman, 2003). Finally, active and abandoned well bores are much more numerous in oil and gas fields than other potential GS sites, and under certain circumstances could serve as potential leakage pathways. For example, in typical productive oil and gas fields, a CO_2 plume with a radius of about 5 km (3.1 miles) may come into contact with several hundred producing or abandoned wells (Celia *et al.,* 2004).

EPA proposed that the Class VI GS requirements would not apply to Class II ER wells as long as any oil or gas production is occurring, but would apply only after the oil and gas reservoir is depleted. Under the proposed approach, Class II wells could be used for the injection of CO_2, as long as oil production is simultaneously occurring from the same formation. The preamble to the proposal sought comment on the merits of this approach.

Some commenters agreed with the proposed approach while others suggested that the approach did not adequately address risks posed to USDWs by injection operations transitioning from production to long-term storage of CO_2. A majority of commenters requested that EPA develop specific criteria for this transition.

Consistent with these comments, EPA determined that owners or operators of wells injecting CO_2 in oil and gas reservoirs for GS where there is an increased risk to USDWs compared to traditional Class II operations using CO_2 should be required to obtain a Class VI permit, with some special consideration for the fact that they are transitioning from a well not originally designed to meet Class VI requirements. Additionally, EPA recognizes that further clarification is needed to sufficiently characterize the factors that lead to increased risks and warrant conversion from Class II to Class VI.

Therefore, today's rule clarifies that Class VI requirements apply to any CO_2 injection project (regardless of formation type) when there is an increased risk to USDWs as compared to traditional Class II operations using CO_2. Traditional ER projects are not impacted by this rulemaking and will continue operating under Class II permitting requirements. EPA recognizes that there may be some CO_2 trapped in the subsurface at these operations; however, if there is no increased risk to USDWs, then these operations would continue to be permitted under Class II.

EPA has developed specific, risk-based factors to be considered by the Director in making the determination to apply Class VI requirements to transitioning wells. EPA believes this approach provides the necessary, site-specific flexibility while providing appropriate protection of USDWs from endangerment. These risk-based factors for determining whether Class VI requirements apply are finalized in today's rule at § 144.19 and include: (1) Increase in reservoir pressure within the injection zone; (2) increase in CO_2 injection rates; (3) decrease in reservoir production rates; (4) the distance between the injection zone and USDWs; (5) the suitability of the Class II AoR delineation; (6) the quality of abandoned well plugs within the AoR; (7) the owner's or operator's plan for recovery of CO_2 at the cessation of injection; (8) the source and properties of injected CO_2; and (9) any additional site-specific factors as determined by the Director. Any single factor may not necessarily result in a determination that a Class II owner or operator must apply for a Class VI permit; rather, all factors must be evaluated comprehensively to inform a Director's (or owners' or operators') decision. The Agency is also developing guidance to support Directors and owners or operators in evaluating these factors and making the determination on whether to apply Class VI requirements.

Owners and operators of Class II wells 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 where there is an increased risk to USDWs compared to traditional Class II operations using CO_2. EPA expects that, in most cases, the ER owners or operators will use these same factors to evaluate whether there is an increased risk to USDWs. When an increased risk is identified, the owner or operator must notify the Director of their intent to seek a Class VI permit. Today's rule clarifies that the Director has the discretion to make this determination in the absence of an owner or operator notification and, in doing so, require the owner or operator to apply for and obtain a Class VI permit in order to continue injection operations (§ 144.19(a)). In the event that an injection operation makes changes to the ER operation such that the increased risk to USDWs warrants transition to Class VI and does not notify the Director, the owner or operator may be subject to specific enforcement and compliance actions to protect USDWs from endangerment, including corrective action within the AoR, cessation of injection, monitoring, and/or PISC under sections 1423 and 1431 of the SDWA.

The Agency acknowledges that some stakeholders and commenters are concerned about the burden that a transition may impose on existing programs. EPA believes that transition to Class VI is necessary to ensure USDW protection but is allowing the constructed components of Class II ER wells to be grandfathered into the Class VI permitting regime at the discretion of the Director and pursuant to requirements at § 146.81(c), in order to facilitate the transition from Class II to Class VI wells without undue regulatory burden. As outlined in section II.G, today's rule clarifies that State oil and gas agencies that oversee the Class II program in many States may assume regulatory authority for Class VI by either a memorandum of understanding with the Class VI primacy agency, or by obtaining primacy for the entire Class VI program as long as it is identified in the State's program description under § 145.23. In this way, the same agency may oversee the Class II and Class VI programs, streamlining the transition process. State primary enforcement responsibility is discussed further in section II.G.

As part of EPA's adaptive rulemaking approach for Class VI wells, the Agency will collect data on transitioning Class II projects to determine whether the factors at § 144.19 adequately address risks to USDWs and whether additional or amended Federal regulations or other actions are warranted for transitioning wells from ER to long-term storage of CO_2.

Class V Experimental Technology Wells: Prior to finalization of the Class VI regulation, a number of CO_2 injection projects were permitted as Class V experimental technology wells for the purpose of testing GS technology in the U.S. Wells permitted under this classification are designed for the purpose of testing new technology that is of an experimental nature. EPA understands that some of the wells previously permitted as Class V experimental technology wells may no longer be used for this purpose. GS wells that are not being used for experimental purposes must be re-permitted as Class VI wells and will be subject to today's requirements.

In the preamble to the proposed rule, EPA described UIC Program Guidance #83 *(Using the Class V Experimental Technology Well Classification for Pilot GS Projects)* and the use of the Class V experimental technology well classification (see section II.E.1 of today's notice). EPA stated that the guidance will continue to apply to experimental projects (as long as the projects continue to qualify as experimental technology wells under the guidelines described in the guidance) and to future projects that are experimental in nature.

Several commenters on the proposed rule asked EPA to clarify the point at which Class V experimental technology wells should be re-permitted as Class VI wells. Today's rule, at § 146.81(c), requires owners or operators of Class V experimental technology wells no longer being used for experimental purposes (*e.g.,* wells that will continue injection of CO_2 for the purpose of GS) to apply for Class VI permits within one year of rule promulgation and to comply with the requirements of today's rule. However, EPA is allowing the constructed components of Class V experimental technology wells to be grandfathered into the Class VI permitting regime at the discretion of the Director and pursuant to requirements at § 146.81(c).

Following promulgation of today's rule, only GS projects of an experimental nature (*i.e.,* to test GS technologies and collect data) will continue to be classified, permitted, and regulated as Class V experimental technology wells; and Class V wells are prohibited from operating as non-experimental GS operations under § 144.15. Experimental projects are those whose primary purpose is to test new, unproven technologies. EPA does not consider it appropriate to permit CO_2 injection wells that are testing the injectivity or appropriateness of an individual formation (*e.g.,* as a prelude to a commercial-scale operation) as Class V experimental technology wells. Such wells should be permitted as Class VI wells.

Other commenters suggested that owners or operators of wells injecting CO_2 into basalts, coal seams, and salt domes should be able to seek a Class V experimental permit. EPA agrees that the Class V experimental technology well classification may be appropriate for these projects provided they are experimental in nature. EPA expects that, following today's rule, a limited number of experimental injection projects testing GS technology will continue. EPA anticipates that these projects will be small-scale and involve limited CO_2 volumes. However, if these projects become larger scale and are no longer experimental, they will need to be permitted as Class VI wells. The construction, operation or maintenance of any non-experimental Class V GS wells is prohibited (§ 144.15).

The Agency is preparing additional guidance for owners or operators and Directors regarding the use of the Class V experimental technology well classification for GS following promulgation of today's rule. The guidance will assist owners and operators and Directors in determining what constitutes a Class V experimental technology well for the purposes of testing GS technology.

Grandfathering for Class I, Class II and Class V Experimental Technology Wells: Recognizing that owners or operators of existing Class I, Class II, and Class V experimental technology wells may seek to change the purpose of their injection well, EPA proposed to give the Director discretion to carry over or "grandfather" the construction requirements (*e.g.,* permanent, cemented well components) provided he or she is able to make a determination that these wells would not endanger USDWs. EPA sought comment on this approach and how the proposed grandfathering provisions for existing wells may affect compliance with Class VI construction requirements.

Nearly all industry commenters favored grandfathering of Class I, II, and V well construction requirements for GS, indicating that most wells are built to appropriate specifications and would have sufficient mechanical integrity for GS in order to protect USDWs from endangerment. These commenters cited oil and gas industry experience with CO_2 injection in the UIC Class II program and suggested that this experience demonstrates that construction requirements for Class II injection wells are sufficient to protect USDWs. Other commenters asserted that grandfathering Class II construction will expedite the transition of Class II ER projects to Class VI GS.

Several commenters were concerned that the structural modifications that may be required for some existing Class II wells to comply with the proposed injection well construction requirements at § 146.86 may actually compromise the integrity of those wells. One commenter also mentioned that pre-existing wells, including wells approved for sequestration as Class I and/or Class II wells, have not been constructed to the same standards. These existing wells penetrating the injection zone may, therefore, become potential threats to USDWs.

In response, EPA recognizes that the oil and gas industry has decades of experience injecting CO_2 for ER and that many Class V experimental technology wells, including those used in the RCSP's projects, are specifically designed for injection of CO_2 and are being constructed to Class I non-hazardous waste well specifications. In today's final rule, at § 146.81(c), owners or operators seeking to grandfather existing Class I, II, or V wells for GS must demonstrate to the Director that the grandfathered wells were engineered and constructed to meet the requirements at § 146.86(a) and ensure protection of USDWs from endangerment in lieu of requirements at § 146.86(b) and § 146.87(a). Based on the owner or operator's demonstration, the Director will determine if a well is appropriately constructed for GS. If the Director determines that the construction is appropriate for GS, the well will be re-permitted as a Class VI well and must meet the operational, testing and monitoring, reporting, injection well plugging, and PISC and site closure requirements in subpart H of part 146. If an owner or operator seeking to grandfather an existing Class I, II, or V well to a Class VI well cannot make this demonstration, then grandfathering of the constructed well and re-permitting as a Class VI well is prohibited.

III. What is EPA's final regulatory approach?

Today's rule creates a new class of injection well (Class VI) under the existing UIC program with new minimum Federal requirements that protect USDWs from endangerment during underground injection of CO_2 for the purpose of GS. Today's action includes requirements for the permitting, siting, construction, operation, financial responsibility, testing and monitoring, PISC, and site closure of Class VI injection wells that address the pathways through which USDWs may be endangered. These requirements are tailored from existing UIC program components to ensure that they are appropriate for the unique nature of injecting large volumes of CO_2 for GS into a variety of geological formations to ensure that USDWs are not endangered.

Today's rule retains many of the requirements for Class VI wells that EPA proposed on July 25, 2008. However, based on a review of public comments on the proposed rule and the NODA and Request for Comment, EPA made several changes to the GS rule. These changes are highlighted as follows and are described in today's publication.

- Additional description of the adaptive rulemaking approach. To ensure USDW protection and meet the potentially fast pace of GS deployment, EPA plans to continue its adaptive rulemaking approach for GS to incorporate new research, data, and information about GS and associated technologies. See section II.F.
- Elaboration on the rationale for allowing States to gain Class VI primacy independent of other well classes. To encourage States to take responsibility for implementation of Class VI regulations and foster a more comprehensive approach to managing GS projects within a broader framework for managing CCS issues, § 145.21 of today's rule allows States to gain primacy for Class VI wells independent of other well classes. See section II.G.
- Explanation of the considerations for permitting wells that are transitioning from Class II to Class VI. To clarify the point at which the purpose of CO_2 injection transitions from ER (*i.e.,* a Class II well) to long-term storage (*i.e.,* Class VI) and the risk posed to USDWs increases and is greater than traditional ER projects injecting CO_2, today's rule at § 144.19 contains specific, risk-based factors to be considered by owners or operators and by Directors in making this determination. See section II.H.
- Incorporation of a process to allow Class VI well owners or operators to seek a waiver from the injection depth requirements. To provide flexibility to address concerns about geologic storage capacity limitations, address injection depth on a site-specific basis, and accommodate injection into different formation types. Today's rule, at § 146.95, allows owners or operators to seek a waiver of the Class VI injection depth requirements provided they can demonstrate USDW protection. Today's final rule also limits the use of aquifer exemptions for Class VI well injection activities (§ 144.7(d)). See section III.D.
- Clarification of the requirements for submitting materials to support Class VI permit applications. Today's rule specifies separate requirements for information to be submitted with the permit application (§ 146.82(a)) and information that must be submitted before well operation is authorized (§ 146.82(c)). This modification addresses comments that not all of the information to support the proposed Class VI permit application requirements will be available at the

time the operator develops their initial permit application, See section III.A.

• Addition of requirements for updating project-specific plans. To ensure that management of GS projects reflect up-to-date information, today's rule requires periodic reviews of the AoR and corrective action, testing and monitoring, and emergency and remedial response plans (§ 146.84(e), § 146.90(j), and § 146.94(d)). Any significant changes to the plans require a permit modification (under § 144.39(a)(5)). See Sections III.F and III.K.

• Increasing the frequency of AoR reevaluations. To address concerns about the inherent uncertainties in modeling CO_2 movement, the emerging nature of GS technology, and the importance of targeting monitoring activities where risk to USDWs is greatest, today's rule at § 146.84(e) requires that the AoR for GS projects be reevaluated at a fixed frequency, not to exceed five years as specified in the AoR and corrective action plan, or when monitoring and operational conditions warrant. See section III.B.

• Clarification and expansion of financial responsibility requirements for Class VI well owners or operators. To ensure that financial resources are available to protect USDWs from endangerment, today's rule (at § 146.85) identifies qualifying financial instruments, the time frames over which financial responsibility must be maintained, procedures for estimating the costs of activities covered by the financial instruments, procedures for notifying the Director of adverse financial conditions, and requirements for adjusting cost estimates to reflect changes to the project plans. See section III.I.

• Revisions to the GS site monitoring and plume tracking requirements to ensure that the most appropriate methods are used to identify potential risks to USDWs posed by injection activities, verify predictions of CO_2 plume movement, provide inputs for modeling, identify needed corrective actions, and target other monitoring activities. Today's rule, at § 146.90(g), requires Class VI well owners or operators to use direct methods to monitor for pressure changes in the injection zone and to supplement these direct methods with indirect, geophysical techniques unless the Director determines, based on site-specific geology, that such methods are not appropriate. See section III.F.

EPA believes that these changes will result in a clearer, more protective approach to permitting GS projects across the U.S. while still allowing for consideration of site specific variability.

In addition to protecting USDWs, today's rule provides a regulatory framework to promote consistent approaches to permitting GS projects across the U.S. and supports the development of a key climate change mitigation technology.

Today's final GS rule contains tailored requirements for geologic siting; AoR and corrective action; construction; operation; monitoring and MIT; recordkeeping and reporting; well plugging, PISC, and site closure; financial responsibility; emergency and remedial response; public involvement; and permit duration of Class VI wells.

To develop today's final regulatory approach, EPA considered public comments submitted in response to the proposed rule and the NODA and Request for Comment. Sections III.A through L focus on the aspects of the GS regulation that are tailored to the unique nature of GS and highlight the changes between the proposed and final GS rule. Additional background information is available in the preamble, NODA and Request for Comment, and docket for this rulemaking.

A. Site Characterization

Today's final action requires owners or operators of Class VI wells to perform a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that GS wells are sited in appropriate locations and inject into suitable formations. Class VI well owners or operators must also identify additional confining zones, if required by the Director, to increase USDW protection.

Site characterization is a fundamental component of the UIC program. Owners or operators must identify the presence of suitable geologic characteristics at a site to ensure the protection of USDWs from endangerment associated with injection activities. Existing UIC regulations for siting injection wells include requirements to identify geologic formations suitable to receive injected fluids and confine those fluids such that they are isolated in order to ensure protection of USDWs from endangerment. Today's rule similarly requires the owner or operator to perform a detailed assessment to evaluate the presence and adequacy of the various geologic features necessary to receive and confine large volumes of injected CO_2 so that the injection activities will not endanger USDWs. Today's requirements for Class VI wells are based extensively on the long-standing site characterization requirements of the UIC program, and are tailored to address the unique nature of GS. Specifically, § 146.83 of today's rule sets forth the criteria for a GS site that is geologically suitable to receive and confine the injected CO_2, while § 146.82 identifies the specific information an owner or operator must submit to the Director in order to demonstrate that the site meets the minimum siting criteria at § 146.83.

Today's rule at § 146.83 retains the minimum criteria for siting as proposed. Owners or operators of Class VI wells must provide extensive geologic data to demonstrate to the Director that wells will be sited in areas with a suitable geologic system comprised of a sufficient injection zone and a confining zone free of transmissive faults or fractures to ensure USDW protection. In addition, the Agency proposed that owners or operators must, at the Director's discretion, identify and characterize additional (secondary) confinement zones that will impede vertical fluid movement. EPA sought comment on the merits of identifying these additional zones, and received many comments on this topic.

The majority of commenters who commented on the requirement to identify additional zones at the Director's discretion disagreed with the proposed approach, saying that the requirement is unnecessary if the injection zone and confining zones were competent, and believing it would reduce the number of GS storage site opportunities. EPA disagrees with the commenters' assertion that secondary confinement and containment zones should not be required under the final rule and received no data or information to support commenters' assertion that characterizing secondary confining zones is technically infeasible. Therefore, EPA is retaining the requirement that owners or operators must, at the Director's discretion, identify and characterize additional confining zones. In certain geologic settings, these zones may be appropriate to ensure USDW protection, impede vertical fluid movement, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation and remediation (§ 146.83(b)).

Today's rule at § 146.82 establishes the detailed information that owners or operators must submit to the Director to demonstrate that the site is suitable for GS. As part of the site characterization and permit application process, owners or operators of Class VI wells are required to submit maps and cross sections describing subsurface geologic formations and the general vertical and lateral limits of all USDWs within the AoR. The Agency anticipates that owners or operators will use existing wells within the AoR or construct stratigraphic test wells for purposes of data collection; such wells may be subsequently converted to monitoring wells. Site characterization identifies potential risks and eliminates unacceptable sites, *e.g.,* sites with potential seismic risk or sites that contain transmissive faults or fractures. Data and information collected during site characterization also inform the development of construction and operating plans, provide inputs for AoR delineation models, and establish baseline information to which geochemical, geophysical, and hydrogeologic site monitoring data collected over the life of the injection project can be compared.

Today's rule also requires owners or operators to submit, with their permit applications, a series of comprehensive site-specific plans: An AoR and corrective action plan, a monitoring and testing plan, an injection well plugging plan, a PISC and site closure plan, and an emergency and remedial response plan. This requirement for a comprehensive series of site-specific plans is new to the UIC program. The Director will evaluate all of the plans in the context of the geologic data, proposed construction information, and proposed operating data submitted as part of the site characterization process, to ensure that planned activities at the facility are appropriate to the site-specific circumstances and address all risks of endangerment to USDWs.

EPA sought comment on the proposed submissions required for permit applications, and received many comments indicating that not all of the information listed in the proposed rule at § 146.82 will be available at the time the operator develops their initial permit application. In response to comments, EPA revised § 146.82 so that the final regulation specifies separate requirements for information to be submitted with the permit application (§ 146.82(a)) and information that must be submitted before well operation is authorized (§ 146.82(c)).

Today's final rule includes requirements at § 146.82(a)(2) that the owner or operator identify all State, Tribal, and Territorial boundaries within the AoR. Based on the information provided to the Director during the initiation of the permit application, the Director, pursuant to requirements at § 146.82(b), must provide written notification to all States, Tribes, and Territories in the AoR to inform them of the permit application and to afford them an opportunity to be involved in any relevant activities (*e.g.,* development of the emergency and remedial response plan (§ 146.94)). These requirements respond to comments received regarding the anticipated large AoRs and injection volumes for GS and the importance of ensuring trans-boundary coordination across the U.S. The Agency encourages transparency in the permitting process and anticipates that State-State/State-Tribal communication on GS permitting will facilitate information sharing and encourage safe, protective projects.

The final GS permitting requirements provided in today's rule in conjunction with the minimum siting requirements at § 146.83 enable flexibility and the discretion of the permitting authority when appropriate, while ensuring USDW protection. This flexibility and permitting authority discretion serves to maximize efficiencies for owners or operators and permitting agencies. The rule enables owners or operators to choose from the variety of technologies and methods appropriate to their site-specific conditions. At the same time, the rule provides the foundation for national consistency in permitting of GS projects. To promote national consistency, the Agency is developing guidance to support comprehensive site characterization required under today's rule.

B. Area of Review (AoR) and Corrective Action

Today's rule at § 146.84 enhances the existing UIC requirements for AoR and corrective action to require computational modeling of the AoR for GS projects that accounts for the physical and chemical properties of the injected CO_2 and is based on available site characterization, monitoring, and operational data. Owners or operators must periodically reevaluate the AoR to incorporate monitoring and operational data and verify that the CO_2 is moving as predicted within the subsurface.

AoR modeling and reevaluation are important components of the overall proposed strategy to track the CO_2 plume and pressure front through an iterative process of site characterization, modeling, and monitoring at GS sites. This approach addresses the unique and complex movement of CO_2 at GS sites.

1. AoR Requirements

Under the UIC program, EPA established an evaluative process to determine that there are no features near an injection well (such as faults, fractures or artificial penetrations) where injected fluid could move into a USDW or displace native fluids into USDWs resulting in endangerment to USDWs. Existing UIC regulations require that the owners or operators define the AoR, within which they must identify artificial penetrations (regardless of property ownership) and determine whether they have been properly completed or plugged. The AoR determination is integral to assessing geologic site suitability because it requires the delineation of the expected extent of the carbon dioxide plume and associated pressure front and identification and evaluation of any penetrations that could result in the endangerment of USDWs. For existing injection well classes (I through V), the AoR is defined either by a fixed radius around the injection well or by a simple radial calculation (40 CFR 146.6).

AoR and corrective action plan: EPA proposed that owners or operators of Class VI wells prepare, maintain, and comply with a plan to delineate the AoR for a proposed GS project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. Commenters supported the proposed requirement for an AoR and corrective action plan, particularly advocating updates that ensure that facilities are being properly managed to address changing circumstances (*e.g.,* addition of monitoring wells or operational changes). The Agency is developing guidance that describes the content of project plans required in the GS rule, including the AoR and corrective action plan.

Today's final rule retains the requirement for owners or operators to develop and implement an AoR and corrective action plan; the approved plan will be incorporated into the Class VI permit and will be considered permit conditions; failure to follow the plan will result in a permit violation under SDWA section 1423. Owners or operators must also review the AoR and corrective action plan following the most recent AoR reevaluation and submit an amended plan, or demonstrate to the Director that no amendment to the AoR and corrective action plan is needed (§ 146.84(e)(4)). The iterative process by which this and other required plans are reviewed throughout the life of a project will promote an ongoing dialogue between owners or operators and the Director. Tying the plan reviews to the AoR reevaluation frequency is appropriate to ensure that reviews of the plans are conducted on a defined schedule, if there is a change in the AoR, or if other circumstances change, while adding little burden if the AoR reevaluation confirms that the plan is appropriate as written. The plan review process also supports development and review of effective testing and monitoring programs. Additional information on updates to the AoR and corrective action plan is discussed in subsequent sections.

AoR definition: In the proposed rule, EPA defined the AoR for a GS project as "the region surrounding the GS project that may be impacted by the injection activity," and stated that "the AoR is based on computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream." Several commenters stated that the proposed AoR definition for Class VI wells was vague and open to broad interpretation, which could lead to overly large or small AoRs. Other commenters believed that specific CO_2 phases and areas of quantitative measures of elevated pressure should be included in the definition.

EPA evaluated all comments on the AoR definition, and determined that a performance-based definition provides sufficient instruction regarding the region that should be included within the AoR. However, to provide additional clarity, EPA modified the Class VI AoR definition for today's final rulemaking. The AoR is defined in the final rule as, "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and displaced fluids and is based on available site characterization, monitoring, and operational data as set forth in § 146.84." The Agency is developing guidance on AoR and corrective action to support AoR delineation (*i.e.,* including regions of the CO_2 plume and pressure front).

Use and applicability of computational models: EPA proposed that the AoR for Class VI wells be determined using sophisticated computational modeling that accounts for multiphase flow and the buoyancy of CO_2, and is informed by site characterization data. EPA proposed that any computational model that meets minimum Federal requirements and is acceptable to the Director may be used, including proprietary models. EPA sought comment on the use and applicability of computational modeling and allowing the use of proprietary models for GS AoR delineation.

Many commenters agreed with EPA that computational multiphase modeling is the most accurate method of delineating the AoR of GS sites. Several commenters also provided detailed technical suggestions regarding how modeling should be conducted. Some commenters opposed the use of computational models, stating that they are overly complicated to use and interpret and are not warranted for protection of USDWs.

EPA agrees with commenters who support the use of computational modeling, and retains the requirement in today's rule at § 146.84(a). The Agency is developing guidance on AoR and corrective action to support the use of computational modeling for AoR delineation. Available data from pilot projects and research studies (*e.g.,* Schnaar and Digiulio, 2009) support today's final approach of requiring the use of computational models to delineate the AoR for GS sites.

Comments were submitted both in support of and against allowing the use of proprietary models. Several commenters who supported allowing the use of proprietary models said that allowing the use of these models will save costs and increase efficiency, as many existing CO_2 injection projects currently rely on proprietary models. However, commenters suggested that the Director be given access to the model in order to fully evaluate results and modeling assumptions. Commenters that opposed the use of proprietary models did not believe that such models are sufficiently transparent, and believed that the Director would not be able to replicate the results.

EPA's final approach allows the use of proprietary models at the discretion of the Director. EPA does not agree with commenters who believe that the use of proprietary models will prohibit full evaluation of model results and assumptions. Several available proprietary models meet minimum Federal requirements for use in AoR delineation and their use has been documented in peer-reviewed research studies. Class VI well owners or operators, including those using proprietary AoR delineation models, are required to disclose the code assumptions, relevant equations, and scientific basis to the satisfaction of the Director. To ensure that all predictive models used for AoR delineation are meeting the Agency's intent, EPA will collect and review project data on models used in early GS projects as part of its adaptive rulemaking approach. See section II.F.

AoR reevaluation: EPA proposed that the AoR delineation be reevaluated periodically over the life of the project in order to incorporate CO_2 monitoring data into models to ensure protection of USDWs from endangerment. Under the proposed approach, AoR reevaluation would occur at a minimum of every 10 years during CO_2 injection, or when monitoring data and modeling predictions differ significantly. EPA sought comment on the requirement for reevaluation every 10 years and what conditions would merit reevaluation of the AoR.

The majority of commenters agreed that AoR reevaluations are necessary, citing the large volumes of CO_2 that may be injected, the uncertainty of CO_2 movement in the subsurface, the need to incorporate monitoring data, and the lack of experience in tracking large volumes of CO_2. EPA agrees with commenters who supported the proposed approach for periodic AoR reevaluation. EPA believes that in order to sufficiently protect USDWs from endangerment, the CO_2 plume and pressure front should be tracked over the lifetime of the project using an iterative approach of site characterization, modeling, and monitoring. Periodic AoR reevaluation, as required in today's final action, is an integral component of this approach. EPA believes that the AoR reevaluation is an efficient use of resources and notes that if the CO_2 plume and pressure front are moving as predicted, the burden of the AoR reevaluation requirement will be minimal. In cases where the observed monitoring data agree with model predictions, an AoR reevaluation may simply consist of a demonstration to the Director that monitoring data validate modeled predictions.

Several commenters supported the proposed reevaluation timeframe of a minimum of 10 years or when monitoring and modeling data differ. However, many commenters believed that 10 years was too infrequent and suggested more frequent reevaluations or basing the reevaluation timeframe on a performance standard, given the potential risks posed by these projects to USDWs and the general uncertainty related to CO_2 movement at GS projects. Based on consideration of public comments, EPA agrees that reevaluations of the AoR every 10 years may not be sufficient, and today's final approach requires an AoR reevaluation at a minimum of once every five years, or when monitoring data and modeling predictions differ significantly. EPA believes that this revised frequency addresses commenters' concerns about the inherent uncertainties in modeling CO_2 movement, the emerging nature of GS technology, and the importance of targeting monitoring activities where risk of endangerment to USDWs is greatest.

2. Corrective Action Requirements

EPA proposed that owners or operators of Class VI wells identify and evaluate all artificial penetrations within the AoR. Based on this review, owners or operators, in consultation with the Director, would identify the wells that need corrective action to prevent the movement of CO_2 or other fluids into or between USDWs. Owners or operators would perform corrective action to address deficiencies in any wells (regardless of ownership) that are identified as potential conduits for fluid movement into USDWs. This inventory and review process is similar to what is required of Class I and Class II injection well owners or operators. The proposal did not prescribe any specific methods or cements that should be used for corrective action, but stated that the methods used must be appropriate for CO_2 injection and compatible with all fluids.

Phased corrective action: Due to the anticipated large size of the AoR for Class VI wells, EPA proposed allowing owners or operators to conduct corrective action on a phased basis during the lifetime of the project, at the discretion of the Director. In these cases, corrective action would not need to be conducted throughout the entire AoR prior to injection. Corrective action would only be necessary in areas near the injection well with a high certainty of CO_2 exposure during the first years of injection as informed by site-characterization data and model predictions. Artificial penetrations in areas farther from the injection well would be addressed after injection has commenced, but prior to CO_2 plume and pressure front movement into that area. The proposal sought comment on allowing for phased corrective action at the discretion of the Director.

The majority of commenters agreed with EPA's proposed approach of allowing phased corrective action at the Director's discretion. Most commenters believed that phased corrective action is a practical and cost effective approach. However, some commenters argued that phased corrective action should be allowed at all sites and not left to Director's discretion. Others argued that specific timeframes (*e.g.,* two to five years) for corrective action should be mandated to ensure that wells are addressed prior to plume movement into that area. Several State commenters disagreed with EPA's proposal to allow phased corrective action and believed that all corrective action should be completed prior to injection.

EPA agrees with commenters who supported allowing for phased corrective action at the discretion of the Director, and retains this provision in today's final regulation at § 146.84(d). Phased corrective action may provide many benefits to a project including spreading corrective action costs throughout the life of a GS project, avoiding delays in project start-up, allowing for use of future, improved corrective action techniques, and addressing unanticipated changes in the movement of the CO_2 plume or pressure front. Given the wide range of conditions and site-specific considerations unique to GS sites, Director's discretion is appropriate as Directors are in the best position to make decisions about the appropriateness of phased corrective action.

EPA agrees with commenters that corrective action on wells should be completed in advance of the anticipated arrival of the CO_2 plume or pressure front. However, it is not appropriate to set a specific timeframe for completing corrective action because CO_2 plume movement will be site-specific and may change over the life of a GS project. Instead, decisions regarding the timing of corrective action will be incorporated into the approved AoR and corrective action plan for each project based on project-specific information. The Agency is developing guidance on AoR and corrective action for GS sites, which addresses the types of issues these commenters raise.

C. Injection Well Construction

Today's rule finalizes requirements (at § 146.86) for the design and construction of Class VI wells using materials that can withstand contact with CO_2 over the life of the GS project in order to prevent movement of fluids into USDWs.

Proper construction of injection wells provides multiple layers of protection to ensure the prevention of fluid movement into USDWs. Today's final approach is based on existing construction requirements for surface casing, long-string casing, and tubing and packer for Class I hazardous waste injection wells, with modifications to address the unique physical characteristics of CO_2, including its buoyancy relative to other fluids in the subsurface and the potential presence of impurities in captured CO_2. In addition to protecting USDWs, today's comprehensive construction requirements respond to concerns about GS project safety and potential impacts on USDWs.

Surface and long-string casing requirements: EPA proposed that surface casing for a Class VI well be set through the base of the lowermost USDW and cemented to the surface; and, that the long-string casing be cemented in place along its entire length from the injection zone to the surface. This is consistent with existing requirements for Class I hazardous waste injection wells.

EPA proposed the enhanced casing requirements for Class VI wells to maintain additional barriers to CO_2 leakage outside of the injection zone, and solicited comment on the proposed construction requirements related to the depth of the surface casing. Commenters objecting to the proposed requirements argued that the surface casing and long-string casing requirements may preclude GS in areas with very deep USDWs. They commented that, under certain circumstances, it would be too burdensome or technologically infeasible to construct the casings to the required depth. Commenters also argued that these requirements would adversely impact acceptance of GS and would slow down large-scale deployment of this climate change mitigation technology. These commenters recommended that the rule allow more flexibility regarding surface and long-string casing depths to accommodate varied conditions where Class VI wells may be constructed throughout the U.S. Other commenters agreed with the Agency's proposed long-string casing requirements for Class VI wells, stating that the requirements prevent undesirable migration of fluids behind the casing and provide maximum zonal isolation.

The Agency disagrees that the surface and long-string casing requirements are not flexible enough to address the varied geological formations and aquifer characteristics across the United States. EPA adds that cementing of deep wells has been performed successfully by owners or operators of Class I wells at depths up to 12,000 feet (USEPA, 2001). Protection of USDWs from endangerment, regardless of their depth or stratigraphic location, is the primary mission of the UIC program and the purpose of all requirements for injection wells.

However, in order to address concerns about lack of flexibility while ensuring USDW protection, EPA modified the surface casing requirements at § 146.86(b) to provide owners or operators flexibility regarding how to complete the surface casing in situations where the cement cannot be re-circulated to the surface. The regulation does not specify how the cementing must be accomplished (*e.g.,* single or staged circulation); instead, it allows flexibility for owners or operators to propose alternative cementing methods that provide a sufficient cement seal and prevent fluid movement through any channels adjacent to the well bore under all circumstances in order to protect USDWs from endangerment. The Agency is retaining the requirements as proposed for long-string casing construction for Class VI wells. To further address comments on deep injection wells, today's final rule includes requirements at § 146.95 for owners or operators that seek a waiver of the injection depth requirements. Owners or operators of wells operating under injection depth waivers must comply with additional construction requirements to ensure that wells used to inject above or between USDWs are protective and will not endanger USDWs. See section III.D for a detailed discussion of the waiver approach.

Cement and well materials requirements: EPA proposed that all materials used in the construction of Class VI wells must be compatible with fluids with which the materials may be expected to come into contact, and that cement and cement additives must be compatible with the CO_2 stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the project. The Agency requested comment on cementing of the long-string casing, including the use of degradation-resistant well construction materials, such as acid-resistant cements and corrosion-resistant casing for Class VI wells.

Commenters who disagreed with EPA's proposed requirements for well materials and cement argued that the specific use of acid-resistant/corrosion-resistant cement is excessive. They expressed concerns that the proposed rule did not reflect actual field experience or recent laboratory research and they encouraged the Agency to defer imposing these additional requirements until further field experience and research are conducted. These commenters suggested that the Agency allow Director's discretion in determining the standards for casing and cementing on a case-by-case basis.

Commenters who supported the use of acid-resistant/degradation-resistant cement and materials asserted that their use is essential to reduce the risk of leaks associated with compromised mechanical integrity and to protect USDWs from endangerment, at a modest cost relative to the long-term benefit of well integrity.

Some commenters supported the use of Class II well construction standards for Class VI wells. These commenters indicated that the oil and gas industry has several decades of CO_2 injection experience, which, they believe demonstrates that Class II construction standards are sufficient to protect human health and the environment. EPA recognizes that the oil and gas industry has experience injecting CO_2 and that many of the wells used for ER may be suitable for GS. However, GS is sufficiently different from Class II ER operations to warrant today's tailored construction requirements for Class VI wells at § 146.86. For example, the volume of CO_2 anticipated to be injected in Class VI wells is significantly greater than for Class II wells. Additionally, formation pressures are expected to be higher as a result of Class VI injection when compared to formation pressures associated with Class II ER projects. Today's final rule does provide for grandfathering of construction for wells transitioning to GS provided the owner or operator can demonstrate to the Director (during the re-permitting process) that wells were constructed and cemented with materials compatible with GS activities; see section II.H.

EPA agrees with commenters that cement additives and degradation resistant materials are crucial to proper construction of Class VI wells. Because of the numerous approaches developed for cement design and due to continually evolving well materials and construction technology (as evidenced by oil and gas industry experience demonstrating the effectiveness of existing cementing materials and procedures), EPA believes it would not be prudent or feasible to specify design standards for cement or cementing procedures, such as wellbore conditioning. Instead, the final rule specifies a performance standard at § 146.86(b)(1) that all casing and cementing or other materials used in the construction of each well have sufficient structural strength, be designed for the life of the GS project, be compatible with the injected fluids, and prevent fluid movement into or between USDWs.

Tubing and packer requirements: EPA proposed that all Class VI wells be constructed with tubing and a packer that is set opposite a cemented interval at a location approved by the Director, and sought comment on this approach. Several commenters agreed with the proposed approach for tubing and packer of Class VI wells, saying that tubing and packer in Class VI wells facilitate continuous monitoring of pressure in the annulus between the tubing and casing and effectively provide two barriers from USDWs. Additionally, tubing can be replaced relatively easily in the event that damage to the tubing is identified or a tubing diameter change is necessary. EPA agrees with commenters that the use of tubing and packer in accordance with specified requirements at § 146.86(c) offers the best multiple-barrier protection of USDWs from endangerment and today's final rule retains this requirement.

Horizontal wells: In the proposed rule, EPA solicited comment on the merits of horizontal well drilling techniques for Class VI wells and the applicability of proposed well construction requirements to horizontal injection well design. Commenters strongly supported the use of horizontal well drilling techniques for Class VI wells. Many commenters cited the oil and gas industry's extensive technical experience with horizontal injection well construction and the practical experience gained at GS pilot projects including the In Salah project in Algeria. Commenters also emphasized that horizontal well drilling helps to reduce surface impact by reducing the number of injection well heads required to achieve a given injection rate, which limits the number of potential leakage pathways into USDWs. Commenters stated that allowing the use of horizontal wells for GS would maximize CO_2 injection volumes into a particular reservoir and increase the total effective GS CO_2 storage capacity in the U.S.

EPA agrees with commenters that horizontal well drilling techniques represent a potential and promising method for increasing efficiency of GS projects while simultaneously reducing impact and potential leakage pathways into USDWs. EPA agrees that using existing experience with horizontal well construction and use in conjunction with the Class VI requirements may help improve efficiency in GS operations while ensuring protection of USDWs from endangerment. Therefore, the Agency will allow the use of horizontal wells for Class VI GS as long as the wells are constructed and implemented to meet the requirements under subpart H of part 146.

D. Class VI Injection Depth Waivers and Use of Aquifer Exemptions for GS

Today's final rule includes requirements at § 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 above and below the injection zone are protected from endangerment. The Agency anticipates that any issuance of waivers will be limited to circumstances where there are deep USDWs (74 FR 44802, August 31, 2009) and/or where the lack of a waiver of injection depth requirements would result in impractical or technically infeasible well construction, and where USDW protection is demonstrated and maintained through the life of the GS project. These requirements are designed to ensure that the owner or operator and the Director consider, on a site-specific basis, the implications, benefits, and challenges associated with GS, water availability, and USDW protection. Today's final rule also establishes limited circumstances under which aquifer exemption expansions may be granted for owners or operators of Class II EOR/EGR wells transitioning to Class VI injection wells for GS.

1. Proposed Rule

Injection depth requirements for GS: In the proposed rule, EPA defined Class VI injection wells as "wells used for GS (injection) of CO_2 beneath the lowermost formation containing a USDW." The proposed injection depth requirements (*i.e.,* that injection is below the lowermost USDW) for Class VI wells are consistent with the siting and operational requirements for deep, technically sophisticated wells and are an important component of the UIC program. The basis for these requirements is the principle that placing distance between the injection formation and USDWs will decrease risks to USDWs. In deep-well injection scenarios, the added depth and distance between the injection zone and overlying formations serve both as a buffer allowing for pressure dissipation and as a zone for monitoring that may detect any excursions (of the injectate) out of the injection zone. Additional depth and distance also allow CO_2 trapping mechanisms, including physical trapping, dissolution of CO_2 in native fluids and mineralization, to occur over time—thereby reducing risks that CO_2 may migrate from the injection zone and endanger USDWs. Added depth also allows the potential for the presence of additional confining layers (between the injection zone and overlying formations/USDWs).

The Agency acknowledged that the proposed injection depth requirements would preclude injection of CO_2 into zones in between and above USDWs and may restrict the use of GS in areas of the country with deep USDWs, where well construction would be impractical or technically infeasible. As proposed, the definition would also have effectively precluded injection of CO_2 into shallow formations such as coal seams and basalts. The Agency requested comment on alternative approaches that would allow injection between USDWs and/or above the lowermost USDW and thus potentially allow for more areas to be available for GS while continuing to prevent endangerment of USDWs.

The Agency received comments in support of, and opposition to, the proposed injection depth requirements for Class VI wells. Commenters who supported the proposed requirements cited the importance of USDW protection, the integrity and importance of the long-standing deep well UIC requirements, and concerns about water availability and the future use of deep USDWs. Commenters also indicated that in the early years of GS deployment, injection depth limitations would be prudent.

Those opposed to the proposed requirements supported allowing injection above and between USDWs. These commenters indicated that injection depth flexibility for GS is important to ensure that no parts of the country are excluded from GS activities and that CCS deployment is not restricted. Other commenters encouraged injection depth flexibility because, they asserted, some Class II, Class III, and Class V operations already inject above the lowermost USDW without any potential for threats to underlying (or overlying) USDWs.

Use of aquifer exemptions for GS: The UIC requirements at §§ 146.4 and 144.7 establish criteria for and afford the Director discretion to issue aquifer exemptions which, when approved, removes an aquifer from protection as a USDW, in accordance with the requirements of § 144.7(b)(1). Generally, aquifer exemptions are granted for mineral or hydrocarbon exploitation by Class III solution mining wells, or by Class II oil and gas-related wells, respectively, and when there is no reasonable expectation that the exempted aquifer will be used as a drinking water supply (see specific aquifer exemption criteria at § 146.4). There are also limited numbers of aquifer exemptions for Class I industrial injection. Aquifer exemptions associated with Class II and Class III operations are generally limited in area (*e.g.,* a quarter of a mile around the injection well-bore for Class II wells). EPA attempts to limit aquifer exemptions for injection operations to the circumstances where the necessary criteria at § 146.4 are met and not, in general, for the purpose of creating additional capacity for the subsurface emplacement of fluids.

The proposed rule acknowledged that there may be situations where owners or operators may seek aquifer exemptions for GS and sought comment on whether aquifer exemptions should be allowed for the purpose of Class VI injection. EPA also requested comment on the conditions under which aquifer exemptions for GS should be approved.

Some commenters encouraged the Agency to allow the use of aquifer exemptions for Class VI injection and indicated that the existing criteria at 40 CFR 146.4 and 40 CFR 144.7 are appropriate for GS. However, a number of commenters requested that the Agency modify the aquifer exemption criteria to provide regulatory certainty and ensure that the criteria specifically apply to CO_2 injection for GS. Other commenters requested that the Agency modify the definition of a USDW to reduce the need for aquifer exemptions (*e.g.,* lowering the upper TDS limit from 10,000 mg/l TDS). Additionally, commenters acknowledged that there was a particular interest in aquifer exemptions for Class II fields that may be used for GS in the future.

Other commenters suggested that the Agency limit or prohibit aquifer exemptions for Class VI injection, citing the need to ensure protection of current and future drinking water resources. Furthermore, several commenters opposed to the use of aquifer exemptions suggested modifications to the definition of a USDW to enhance protection for formations in excess of 10,000 mg/l TDS.

Injection formations for GS: In the preamble to the proposed rule, EPA discussed and sought comment on the range of target geologic formations used or under investigation for GS of CO_2 (*e.g.,* deep saline formations, depleted oil and gas reservoirs, unmineable coal seams, basalts, and other formations). The proposed rule also sought comment on whether the final rule should prohibit injection into any specific formation types that are located above the lowermost USDW.

Most commenters encouraged EPA not to automatically exclude any potential injection formations for GS at this stage of deployment. Commenters suggested, in particular, that there is a sufficient technical basis and scientific evidence to allow GS in depleted oil and gas reservoirs and in saline formations, noting that there is consensus on how to inject into these formation types.

Some commenters, including water associations, cautioned the Agency regarding injection into saline formations, citing concerns about the potential future need for these formations as drinking water sources. Other commenters suggested that basalts, salt domes, shales, coal seams, limestone formations, and fractured karst are not ready for commercial sequestration and suggested that additional research is needed into GS in these formation types.

More detailed information on the comments is available in the NODA and Request for Comment and in the docket for this rulemaking.

2. Notice of Data Availability and Request for Comment

In response to comments received on the proposed injection depth requirements, the Agency published a NODA and Request for Comment to present additional information on an alternative for addressing injection depth in limited circumstances where there are deep USDWs and injection above and between USDWs would not endanger USDWs. Under the approach, the proposed Class VI injection depth requirements would remain unchanged but would allow an owner or operator seeking to inject into non-USDWs above or between USDWs to apply for a waiver from the injection depth requirements. The waiver process, presented in the NODA and Request for Comment, would be informed by site-specific information and would be reviewed by both the UIC and Public Water System Supervision (PWSS) Directors to ensure appropriate siting of a GS project as well as consideration of water resource availability and demands.

The NODA and Request for Comment sought comment on the merits of the injection depth waiver approach and whether the waiver process should apply only to saline formations and oil/gas reservoirs or to all formation types. Additionally, the Agency requested information on (1) locations in the U.S. where injection depth is an issue; (2) data and information on the safety of injecting through/above/between USDWs; and, (3) strategies being considered by States, Tribes, and Regions to address competing resource issues. The Agency requested this information to enable a more comprehensive decision regarding the impacts of the proposed injection depth requirements and the need for waivers.

Comments on the waiver alternative presented in the NODA and Request for Comment: The Agency received comments both in support of and opposition to the injection depth waiver alternative discussed in the NODA and Request for Comment.

Commenters supporting the waiver alternative presented in the NODA and Request for Comment acknowledged that the waiver approach is flexible, strikes the right balance between USDW protection and maximizing GS capacity, and would ensure a thorough and scientifically based, site-specific assessment of the appropriateness of a waiver during the siting process. A number of commenters supportive of the waiver cited hydrocarbon storage, other injection operations, and production activities as evidence that GS into shallower geologic environments can be performed safely and successfully while ensuring USDW protection.

There was limited opposition to the waiver alternative presented in the NODA and Request for Comment. Commenters who opposed the waiver approach maintained that all injection of CO_2 for GS should be below the lowermost USDW and any new requirements should maximize protection of USDWs. However, some commenters who opposed the waiver process acknowledged the utility of the waiver, and urged the Agency to consider additional requirements for any wells that operate under injection depth waivers. The Agency did not receive any analytical or quantitative data in response to publication of the NODA and Request for Comment.

The Agency also received comments on the waiver application and review process. Commenters questioned how the process would work and how waivers would apply to existing Class I, II, or V wells that may be re-permitted as Class VI wells in the future. Some commenters suggested that the waiver request should be part of the permit application process, while others felt that it should be a discrete submittal. Other commenters expressed concern about the nexus between the waiver process and aquifer exemptions. Some commenters who supported the waiver concept suggested that adoption of an injection depth waiver process should not be at the discretion of the individual UIC program Directors and that EPA should require all States to include a waiver process.

A number of commenters supporting the concept of the waiver of injection depth requirements indicated that they did not support the joint review of waiver information by both the UIC and PWSS Directors. These commenters believed that the joint review process as discussed in the NODA and Request for Comment was inefficient and duplicative, and could introduce confusion and lack of clarity about the role of each Director. However, a number of commenters did support the principle of affording the PWSS Director a consultative role for increased transparency and to ensure consideration of public water supply needs in a potential GS project area when siting a Class VI well.

Noting the unique nature of the waiver process and the belief that injection above USDWs may present additional questions relative to movement of CO_2 in the subsurface, many commenters supported the Agency's assertion that additional requirements should apply to waivered wells. These commenters suggested that additional regional, hydrologic studies be required when an injection depth waiver is considered. Other commenters encouraged EPA to enhance the site characterization requirements when a waiver is granted to (1) ensure the identification of appropriate upper and lower confining units, (2) include requirements for more comprehensive, site-specific monitoring (above and below the injection zone), and (3) ensure appropriate public notification prior to issuance of a waiver. A number of commenters also suggested that the Agency develop guidance to support the waiver application process, waiver evaluation, and decision making.

Comments on the use of aquifer exemptions for GS: Comments submitted in response to the NODA were similar to and built upon those received on the proposal. Some commenters indicated that, in addition to allowing injection above and between USDWs (through the waiver process), aquifer exemptions should also be allowed for Class VI injection. A number of these commenters requested that the Agency modify (1) the aquifer exemption criteria to ensure that the criteria specifically apply to CO_2 injection for GS and (2) the USDW definition to limit protection for formations currently afforded protection under the SDWA (*i.e.,* by reducing the 10,000 mg/l TDS threshold). These commenters added that Class II EOR/EGR operations injecting into exempted aquifers would need a mechanism to continue the aquifer exemptions if the well were to be re-permitted as a GS operation.

However, a number of commenters encouraged the Agency to limit or prohibit aquifer exemptions for Class VI injection, citing the need to ensure protection of current and future drinking water resources. Furthermore, several of these commenters suggested modifications to the definition of a USDW to enhance protection for formations in excess of 10,000 mg/l TDS.

Comments on injection formations for GS: Commenters submitted comments similar to those received on the proposal. Some commenters encouraged the Agency to limit GS injection to only deep saline formations and depleted reservoirs. These commenters cited a lack of information about the viability of basalts, salt domes, shales, and coal seams for GS. Other commenters suggested that the Agency allow injection into all formation types for GS. Commenters that supported flexibility in injection formation types indicated that proper site-characterization is critical, regardless of the injection formation type. They indicated that a decision to allow injection for GS should be made on a site-by-site basis and a prohibition based on formation types is not appropriate.

3. Final Approach

In response to comments on the proposed injection depth requirements, the use of aquifer exemptions for GS, the range of potential injection formations for GS, the waiver process discussed in the NODA and Request for Comment, and concerns about USDW protection and national capacity for GS, today's rule finalizes requirements at § 146.95 that allow owners or operators to seek a waiver of the Class VI injection depth requirements for injection into non-USDW formations above and/or between USDWs. It establishes: (1) Requirements specifying information that owners or operators must submit, and Directors must consider, in consultation with PWSS Directors; (2) procedures for public notice of a waiver application and for Director-Regional Administrator communication; (3) the waiver issuance process; and (4) additional requirements that apply to owners or operators of Class VI wells granted a waiver of the injection depth requirements to ensure USDW protection above and below the injection zone. Today's final rule also establishes limited circumstances under which expansions of aquifer exemptions may be granted for owners or operators of Class II EOR/EGR wells transitioning to Class VI injection for GS. Additionally, today's rule does not categorically preclude or prohibit injection into any type of formation.

The Agency is finalizing these requirements to ensure USDW protection while providing flexibility to UIC program Directors and owners or operators who will undertake CO_2 injection for GS. The Agency believes this approach: (1) Responds to concerns about local and regional geologic storage capacity limitations imposed by the proposed injection depth requirements; (2) allows for a more site-specific assessment of injection depth for GS projects; (3) accommodates injection into different formation types; (4) allows for injection of CO_2 for GS into non-USDWs above and/or between USDWs when appropriate and where it can be demonstrated that USDWs will be protected from endangerment; and (5) responds to concerns about the use of aquifer exemptions for GS. Finally, EPA's approach to addressing injection depth variability through a waiver process responds to concerns about future drinking water resource availability and the need to ensure that high quality water remains available in sufficient quantities to supply drinking water needs.

The final injection depth waiver requirements at § 146.95 apply to all non-USDWs including: (1) Formations that have salinities greater than 10,000 mg/l TDS and (2) all eligible previously exempted aquifers situated above and/or between USDWs. EPA anticipates that previously exempted aquifers will, in many cases, not be appropriate receiving formations for GS due to their location, size, lithologic properties, and previous injection operations; and, therefore, the Agency expects that few owners or operators will seek Class VI permits for GS injection into previously exempted aquifers.

Injection depth waivers for GS: Today's final rule requires an owner or operator seeking a Class VI waiver of the injection depth requirements to submit additional information to the Director to inform a comprehensive assessment of site-suitability for a Class VI well to inject into a non-USDW above or between USDWs. The Agency believes that it is appropriate and reasonable that the owner or operator and the Director consider additional, specific information prior to waiver issuance in addition to the required Class VI permit information and the site characterization information collected (pursuant to requirements at § 146.82(a) for the site-specific characterization of geologic, hydrogeologic, geochemical, and geomechanical properties and § 146.83 to determine the suitability of the proposed GS site).

In addition to submitting a Class VI permit application, the owner or operator must also submit a supplemental report (the GS Class VI injection depth waiver application report) referenced at § 146.82(d) and outlined at § 146.95(a) with additional, specific information including: Information about the injection zone; identification of confining units above and below the injection zone; tailored AoR modeling above and below the injection zone; a demonstration that well design is appropriate and protective of USDWs, in lieu of specific well construction requirements at § 146.86; a description of how monitoring will be tailored for injection above/between USDWs; and information about public water supplies in the AoR. The purpose of the report is to ensure that the owner or operator collects appropriate information and demonstrates to the Director that the injection zone is suitable for GS and is confined by confining units above and below the injection zone; that well construction, operation, and monitoring are tailored for the site; and, that USDWs are not and will not be endangered. This report, suggested by commenters on the NODA and Request for Comment, ensures that waiver information is discrete from the permit application as indicated at § 146.82(d) and must be made available to the UIC Director, PWSS Directors, the Regional Administrator, and the public when the waiver is publicly noticed with the draft, Class VI permit application.

EPA believes that, to be effective, a waiver of injection depth requirements should be granted only after the UIC program Director, the PWSS Director(s), and the public have evaluated information specific to the site and anticipated injection activity. In addition, the decision to waive injection depth requirements must be made using a clear and transparent public notification process. The requirements at § 146.95(b) establish considerations that the UIC Director must assess when evaluating a waiver application in conjunction with the permit application for a Class VI GS project. These are designed to ensure that USDW protection, site-specific drinking water resource issues, and the use and impact of GS technologies are considered and documented. The requirements at § 146.95(b)(2) also establish the manner in which the UIC Director will consult with the PWSS Director(s) of States, Territories, and Tribes having jurisdiction over lands within the AoR of a well for which a waiver is sought to ensure that water system concerns are considered when evaluating a waiver application. The communication with the PWSS Director is consultative and does not constitute a final Agency decision.

Under § 146.95(c) and pursuant to requirements at § 124.10, the public notification process for a waiver of injection depth requirements for a Class VI well must occur concurrently with the Class VI permit notification in order to ensure that all necessary information is disclosed to the public for notice and comment and that the public understands that the site, if permitted, would be operating under a waiver from the injection depth requirements. In addition, the rule at § 146.95(c) requires the Director to provide the public with appropriate, site-specific and waiver-specific information to inform public comment. If the permitting authority receives comments on the injection depth waiver during the public comment period for both the waiver and the permit application, the Director must evaluate comments prior to approving the waiver and issuing the Class VI permit. These requirements balance USDW protection and disclosure of PWSS information with the GS permit application process requirements.

Today's final regulations, at § 146.95(d), require the Director to provide the Regional Administrator with the information collected during the waiver application and the public notice processes. Based on this information and pursuant to requirements at § 146.95(d), the Regional Administrator will provide written concurrence or non-concurrence regarding waiver issuance. The requirements at § 146.95(d)(1) afford the Regional Administrator discretion to request limited, additional information to support the waiver decision. The Regional Administrator also has the discretion to require re-initiation of the public notice and comment period if necessary. Today's rule at § 146.95(d)(2) clarifies that Directors of State-approved programs shall not issue waivers without the written concurrence of the Regional Administrator. EPA believes Agency input is necessary in making injection depth waiver decisions and agrees with commenters who expressed interest in ensuring that multi-State boundary and water resource issues are addressed. EPA also believes that Agency involvement in the waiver decision process will contribute to national consistency in waiver issuance.

The requirements at § 146.95(e) identify the information that EPA will maintain on its Web site to provide transparency and inform the public regarding GS injection depth waiver issuance throughout the U.S.

Today's rule finalizes additional requirements at § 146.95(f) to address comments and provide clarity to owners or operators who receive and operate with a waiver of the Class VI injection depth requirements. These requirements are a supplement to all other applicable requirements finalized today (see § 146.95(f)(1)). The additional requirements are designed to complement existing requirements by:

- Building upon the site characterization and AoR delineation conducted during the waiver application process (at § 146.95(a)),
- Supplementing specific requirements that are not applicable due to the fact that certain Class VI requirements (*e.g.,* at § 146.86) reference the "lowermost USDW,"
- Expanding the monitoring requirements during operation and PISC to address protection of USDWs underlying and overlying the injection zone, and,
- Ensuring protection of USDWs above and below an injection zone when a Class VI well is issued a waiver of the injection depth requirements.

The Agency believes that collection and assessment of site- and project-specific information is integral to the waiver process. The Agency is developing guidance to support owners or operators in assessing a GS project site and applying for a waiver of the Class VI injection depth requirements and to assist Directors in evaluating waiver applications.

Today's final approach for injection depth waivers represents minimum Federal requirements. Adoption of the waiver process will remain at the discretion of individual UIC programs, since States may choose to develop requirements that are more stringent than the minimum Federal requirements provided in today's rule. Furthermore, States, Territories and Tribes may be prohibited by state law from allowing such a waiver process. Therefore, States, Territories, and Tribes seeking primacy for Class VI wells are not required to provide for injection depth waivers in their UIC regulations and may choose not to make this process available to owners or operators of Class VI wells under their jurisdiction. Although some commenters asked EPA to require that waivers be applied nationally, the Agency believes that the decision about whether a waiver program is appropriate in a specific State, Tribe, or Territory should be made by each program. This approach allows flexibility for individual program Directors to determine the appropriateness of allowing for waivers based on regional or State-specific conditions, such as the predominant geologic settings anticipated to be used for GS or other land uses in the State while ensuring maximum protection of USDWs from endangerment. UIC program Directors may adopt GS requirements that do not allow injection above or between USDWs if they determine this to be appropriate or if State law prohibits the injection depth waiver process.

No waivers can be issued prior to the establishment of a Class VI UIC program in a State, pursuant to the requirements at § 145.21(see section II.E.2). This is designed to ensure that States determine whether a waiver process will be allowed as a part of their GS program.

Use of aquifer exemptions for GS: Today's rule allows for the expansion to the areal extent of existing aquifer exemptions for Class II EOR/EGR wells transitioning to Class VI injection for GS pursuant to requirements at §§ 146.4 and 144.7(d). Today's final rule also precludes the issuance of new aquifer exemptions for Class VI wells. Aquifer exemptions will only be granted for projects that are transitioning from Class II EOR/EGR wells to Class VI, and are referred to as aquifer exemption expansions below. However, Class VI owners or operators granted expansions of existing Class II EOR/EGR aquifer exemptions for GS projects must meet all of the tailored requirements for Class VI wells in today's rule, except where there are specific provisions for grandfathering of constructed wells pursuant to requirements at § 146.81(c).

If an owner or operator applies for a Class VI permit to inject CO_2 into a previously exempted aquifer (non-USDW) that is located above and/or between USDWs, the permit applicant must also apply for a waiver of the injection depth requirements pursuant to § 146.95 to ensure that if a waiver is granted, USDWs above and below the injection zone are protected from endangerment.

While the Agency developed the waiver process to address comments and concerns about: (1) Current and future drinking water resources and (2) the use of climate mitigation technology at appropriate sites, the Agency acknowledges that there are limited circumstances where aquifer exemptions for GS may be warranted. The aquifer exemption requirements in today's final rule afford owners or operators an opportunity to assess and select a suitable GS site while also preserving USDWs (*i.e.,* formations/aquifers afforded SDWA protection). EPA agrees with commenters who expressed concerns about USDW preservation and protection and believes that, in most cases, the injection depth waiver is a more appropriate option than aquifer exemptions for Class VI injection, and believes that aquifer exemption expansions for GS should be granted in limited circumstances.

The aquifer exemption requirements and the injection depth waiver requirements serve different purposes. An aquifer exemption removes the injection formation from SDWA protection as a USDW and allows injection (*i.e.,* permitted or rule authorized) into an exempted formation, while an injection depth waiver allows (Class VI) CO_2 injection for GS above or between USDWs and ensures protection of USDWs above and below the injection zone (which may be an exempted aquifer).

The Agency recognizes that a limited number of Class II EOR/EGR well owners or operators currently inject into exempted aquifers or exempted portions of aquifers and these owners or operators may transition to Class VI GS in the future (see section II.H). In response to commenters who believed that there is a need for aquifer exemptions in specific circumstances and in an effort to maintain USDW protection while providing flexibility to transitioning projects, today's rule allows owners or operators of Class II EOR/EGR operations injecting into exempted aquifers (or exempted portions of aquifers) to reapply for an aquifer exemption expansion for the re-permitted Class VI injection.

For all Class II EOR/EGR aquifer exemption expansions for Class VI injection, public notice and opportunity for a public hearing is required under § 144.7(b)(3). In addition, today's rule requires that all such aquifer exemption expansion requests be treated as substantial program revisions under § 145.32 and will require revision of part 147. Furthermore, if EPA directly implements the UIC program in a State, an aquifer exemption expansion requires a revision to the UIC program of the applicable State under part 147.

The Agency acknowledges that the expansion of an existing aquifer exemption for a GS project will remove additional USDWs (or portions of USDWs) from SDWA protection, and that owners or operators of other classes of injection wells could apply for a permit to inject into these exempted aquifers. However, EPA clarifies that aquifer exemption expansions granted under today's rule will only be granted for the purpose of GS (and the injection will be subject to today's tailored requirements for Class VI wells). Any other uses of an exempted aquifer (*e.g.,* for Class I through V injection) require a separate permit, are subject to existing UIC requirements, and must be approved by the UIC Director. The Agency anticipates that a UIC Director will (and encourages the UIC Director to) consider the following types of risks when evaluating additional injection activities into the AoR of a GS project: The number of artificial penetrations in the AoR, potential adverse geochemical interactions between previously injected CO_2 and other injection fluids, and an increase in reservoir pressure as a result of multiple injectors and subsurface plume interaction. EPA believes that these factors would reduce the likelihood that exempted aquifers associated with GS injection will be used for other activities.

Additionally, the Agency recognizes that an owner or operator could, in theory, request multiple expansions to the areal extent of a previously exempted aquifer used for Class II EOR/EGR injection. However, due to the nature of Class VI operations including the permit application process, the AoR evaluation, and the development of site-specific plans, the Agency anticipates that an owner or operator will not be able to continually expand an aquifer exemption for a Class VI operation. Instead, the applicant should identify, up front, the predicted extent of the injected CO_2 plume and any mobilized fluids that may result in degradation of water quality over the lifetime of the GS project to develop an appropriate aquifer exemption request. Identification of the areal extent of the expanded aquifer exemption must be informed by computational modeling of the site developed for delineation of the AoR, and be of sufficient size to cover any possible changes to the computational model that may arise during future reevaluation of the AoR over the life of the project.

Pursuant to requirements at § 144.7(d)(2), the Director will comprehensively evaluate the permit application information in concert with the areal extent of the aquifer exemption expansion request. The purpose of these requirements is to ensure USDW protection while developing an exemption expansion that is commensurate with the Class VI injection project, for the life of the project, to reduce the potential need for additional expansions of a specific aquifer exemption for Class VI injection in the future.

Furthermore, in the event that a Class VI owner or operator obtains evidence based on monitoring data collected at the GS site, as required by § 146.90(g), that non-exempted, USDW portions of the aquifer (*i.e.,* on the periphery of the exempted aquifer) may be endangered by the injection activity, the owner or operator must immediately cease injection and implement the Emergency and Remedial Response Plan approved by the Director pursuant to requirements at § 146.94. Additionally, the Agency clarifies that such USDW endangerment is a violation of the UIC requirements and associated Class VI permit conditions (*e.g.,* § 144.12; § 146.86, etc.).

Today's final approach is designed to ensure that the differences between traditional Class II EOR/EGR operations and Class VI operations are considered during the aquifer exemption application process and the Class VI permitting process. These differences include the anticipated large CO_2 injection volumes associated with GS, the buoyant and mobile nature of the injectate, and its corrosivity in the presence of water. The Agency believes that this process will encourage owners or operators and Directors to consider the use of alternative formations for GS, including non-USDW formations through the waiver process, prior to applying for or approving aquifer exemption expansions for Class II EOR/EGR wells transitioning to Class VI GS operations. See the discussion on injection depth waivers for GS for information on scenarios that will require the use of both aquifer exemptions and waivers in this section.

Injection formations for GS: In response to comments received on the proposal and the NODA and Request for Comment, today's rule does not categorically preclude or prohibit injection into any type of formation. Instead, the requirements are designed to ensure protection of USDWs from endangerment through proper siting, well construction, operation, monitoring, and PISC at all sites selected for GS.

EPA recognizes that some types of formations, such as coal seams and basalts, are typically shallow and above the lowermost USDW. EPA expects that injection wells conducting GS in these shallow formations will be permitted as Class VI wells and such wells will be issued waivers, provided that their owners or operators can meet all of the requirements for an injection depth waiver at § 146.95 and demonstrate that such injection can be performed in a manner that protects USDWs. EPA adds that wells used to inject into these formation types or other formation types (*e.g.,* salt domes and shales) for experimental purposes would be permitted as Class V experimental technology wells. See section II.H for additional information on the use of the Class V experimental technology well classification following finalization of today's rulemaking.

To facilitate experimental injection for GS and to increase understanding of injection into basalts, shales, and other formation types, EPA is preparing additional guidance for owners or operators and Directors regarding the use of Class V experimental technology wells for GS following promulgation of today's rule.

Adaptive approach: In the early stages of GS deployment, EPA will collect and review project data on GS projects, including information on any Class VI wells granted a waiver of the injection depth requirements and any aquifer exemption expansions issued for Class II EOR/EGR wells transitioning to Class VI GS. Given the unique nature of the waiver of injection depth requirements, the Agency will further assess if the requirements provided in § 146.95 are appropriately designed to evaluate waiver applications, issue waivers, and ensure protection of USDWs. The adaptive approach will also afford the Agency an opportunity to assess the manner in which waivers and expansions of existing Class II EOR/EGR aquifer exemptions for GS are issued across the U.S. and evaluate the applicability of injection into all formation types.

E. Injection Well Operation

Today's final rule contains tailored requirements at § 146.88 for the operation of Class VI wells, including injection pressure limitations, use of down-hole shut-off systems, and annulus pressure requirements to ensure that injection of CO_2 does not endanger USDWs.

The requirements for operation of Class VI injection wells are based on the existing requirements for Class I wells, with enhancements to account for the unique conditions that will occur during GS including buoyancy, corrosivity, and higher sustained pressures over a longer period of operation.

Injection pressure limitations: EPA proposed that owners or operators limit injection pressure such that pressure in the injection zone does not exceed 90 percent of the fracture pressure of the injection zone, and that injection may not initiate new fractures or propagate existing fractures. Most commenters opposed an arbitrary pressure limit, and advocated setting pressure limitations on a site-specific basis. Today's final rule retains the requirement that pressure in the injection zone must not exceed 90 percent of the fracture pressure of the injection zone (§ 146.88(a)). The calculated fracture pressure—and therefore, the injection pressure limit—are based on site-specific geologic and geomechanical data collected during the site characterization process as advocated by commenters.

Annulus pressure: EPA proposed that owners or operators fill the annulus with an approved non-corrosive fluid and maintain pressure on the annulus that exceeds the operating injection pressure. Many commenters disagreed with the requirement to maintain an annulus pressure greater than the injection pressure because they indicated that this could increase the potential for damage to the well.

EPA acknowledges that, in some circumstances, maintaining an annulus pressure greater than the injection pressure could result in a greater chance for damage to the well or the formation. As a result, the final rule provides the Director discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation. EPA changed the requirements in § 146.88(c) to: "The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs."

Automatic down-hole shut-off devices: EPA proposed that owners or operators install and use alarms and automatic down-hole shut-off systems, in addition to the use of surface shut-off devices, to alert the owner or operator and shut-in the well in the event of a loss of mechanical integrity. Automatic down-hole shut-off devices are valves located in the well tubing (at a depth established based on the location of USDWs) that are set to close if triggered by changes in flow rate or other monitored parameters. Automatic surface shut-off valves are commonly used in the oil and gas industry to prevent further well complications in the case of a triggered event such as inadvertent well backflow during a workover. The Agency sought comment on the merits of requiring such devices.

Commenters, including representatives of water associations, supported the requirement to construct Class VI wells with automatic down-hole shut-off devices. These commenters suggested that automatic down-hole shut-off devices provide an additional barrier against upward migration of CO_2 and serve as an additional level of protection when used in concert with surface shut-off devices.

Many industry commenters disagreed with the requirement to construct Class VI wells with automatic down-hole shut-off devices. These commenters indicated that down-hole shut-off devices are redundant of surface devices and unnecessary and would not provide additional protection to USDWs. Commenters suggested that these devices are more appropriate for offshore wells and that the likelihood of damage to surface wellheads is small. Other commenters stated that installation of automatic down-hole shut-off devices in new and pre-existing deep injection wells is complex and servicing of the devices necessitates removal of the tubing. Commenters also indicated that the use of such devices can complicate routine testing and well workovers, and that failure of such devices could damage the well. Several commenters suggested alternatives to automatic down-hole shut-off devices including: Use of wireline retrievable plugs with landing nipples; and use of well materials designed to withstand the proposed injection pressures.

EPA evaluated the range of comments on this topic and maintains that down-hole shut-off devices are an important barrier against endangerment of USDWs from the escape of CO_2. While stakeholders commented that automatic down-hole shut-off devices are primarily used in offshore oil and gas production applications, they are currently used in other situations where loss of well integrity could result in damage to the well or harm to humans (*e.g.,* near high-density population areas, or in onshore acid gas injection; IEA, 2003). While commenters indicated that down-hole monitoring is more difficult, or impractical with an automatic down-hole shut-off device in place, EPA has identified examples of documented logging techniques, including ultrasonic and temperature logs, that can be performed with an automatic down-hole device emplaced (Julian *et al.,* 2007; Somaschini *et al.,* 2009). They are also used in high pressure, high temperature onshore wells and in permafrost areas.

EPA recognizes that, in limited circumstances, the sudden closing of an automatic shut-off valve could cause damage to a well, and that some of these devices may make well maintenance and operation more challenging. Additionally, EPA recognizes that well complications may increase as the frequency of routine or unexpected down-hole device maintenance workovers increases. However, the buoyant nature of CO_2 and the elevated injection pressures associated with GS increase the likelihood of an uncontrolled flow of CO_2 out of the well. If CO_2 does begin to flow back up an injection well, it will rapidly cool and expand as it moves toward the surface and can result in a stream of solid CO_2 which can cause damage to the wellhead and other well instrumentation; such damage has been documented in CO_2 ER wells (Skinner, 2003; Duncan *et al.,* 2009). Automatic shut-off devices can help prevent such occurrences.

After evaluating the risks and benefits of down-hole shut-off systems and considering additional research, EPA will not require automatic down-hole shut-off devices for onshore Class VI wells. Instead, the final rule, at § 146.88(e)(2), requires that owners or operators of onshore Class VI wells install automatic surface shut-off devices, and affords Director's discretion to mandate automatic down-hole shut-off devices in onshore situations that may warrant their use. EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection.

Today's rule, at § 146.88(e)(3), requires the installation of down-hole shut-off devices for Class VI wells located in the offshore submerged lands within the jurisdiction of a State UIC program. The Agency believes that the unique construction and operational conditions for offshore Class VI wells, including isolation from shorelines and the need to construct wells through the water column and the subsurface, may delay response time in the event of well difficulties. These conditions merit requiring automatic down-hole shut-off devices for offshore wells in the submerged lands of a State.

In the event of onshore or offshore well complications, an automatic surface or down-hole shut-off device will immediately shut-in the well to cease injection (limiting CO_2 volume associated with the event), isolate the injectate, and minimizes the risk of subsurface fluid movement and associated problems that may endanger USDWs. EPA believes that requiring the installation of automatic surface shut-off devices for onshore wells (and affording Director's discretion to require down-hole devices where necessary) and automatic down-hole shut-off devices for offshore wells in submerged lands within the jurisdiction of a State ensures that proper precautions are taken to prevent subsurface fluid movement and ensure protection of USDWs, human health, and the environment.

Well stimulation: In the proposed rule, EPA sought comment on whether well stimulation or fracturing to enhance formation injectivity is appropriate and should be allowed for Class VI wells. EPA also requested submittal of information from commenters to better qualify the use of hydraulic fracturing for well stimulation in specific geologic settings and various lithologies. Well owners or operators often use stimulation techniques, including intentionally creating new or propagating existing fractures in the injection zone on wells that have experienced decreased oil and gas production. Additionally, increasing the number and size of fractures surrounding the injection zone can enhance or increase the injectivity of the formation. However, if fractures extend to the confining layer, USDWs can be endangered.

Some commenters stated that while stimulation using a range of techniques including hydraulic fracturing is not appropriate in all geologic settings it should be allowed for Class VI wells. Commenters supported the requirement that hydraulic fracturing only be allowed during well stimulation, noting that ER operations have successfully employed hydraulic fracturing to increase well injectivity without damaging the confining layer. These commenters thought that enhancing injectivity through stimulation would allow injection to occur with fewer injection wells and therefore fewer penetrations of the confining layer.

Many commenters indicated that the Director should be able to determine, based on site-specific information, whether stimulation techniques would pose a risk to the confining layer. Some commenters proposed considerations for determining whether stimulation, including hydraulic fracturing, is appropriate in a given situation and acknowledged that tools exist for owners or operators and Directors to manage the safe use of well stimulation practices. These tools include use of monitoring programs or computer simulations in conjunction with stimulation activities to determine if stimulation is negatively impacting confining layers. Others suggested that open-hole injection zones and multiple injection points can also aid in increasing well injectivity.

A water association commented that activities such as hydraulic fracturing should not be allowed under any circumstances in order to prevent fracturing of the confining layer and the opening of pathways for fluid migration into a USDW.

EPA agrees with commenters that well stimulation may be appropriate in situations where it is determined that it will increase well injectivity and provide better performance for some projects. However, EPA believes that protection of USDWs from endangerment is critical and the primary purpose of UIC regulations pursuant to SDWA. In order to allow appropriate well stimulation while protecting confining layers and USDWs, EPA intends to allow stimulation only at the discretion of the Director. The Director is in the best position to determine if well stimulation techniques, including but not limited to hydraulic fracturing, are appropriate in a given situation. EPA has added a requirement at § 146.91(d)(2) that the owner or operator must notify the Director before any stimulation activities are undertaken. Such notice will provide the Director an additional opportunity to review stimulation plans, assess the description of stimulation fluids to be used, determine that stimulation will not interfere with containment, assess plan appropriateness, and potentially witness the stimulation activity. Although the plan will already have been approved by the Director as part of the permit application process and incorporated into the permit, this notification requirement gives the Director an opportunity to reassess the proposed stimulation activities in light of any new information. In order to preserve the integrity of the confining layer, EPA is retaining the prohibition against fracturing the confining layer at any time and adds that fracturing should not be allowed except during well stimulation. EPA clarifies that under no circumstances may stimulation endanger USDWs.

Tracers: In the proposed rule, EPA sought comment on the use of tracers in GS operations. Tracers are inert compounds added to or naturally occurring in the injection fluid, which can be easily detected through monitoring wells or through surface monitoring techniques. Detection of the tracer would indicate a leak of the injection fluid from the injection zone. Many types of tracers are available, including perfluorocarbons, SF_6, noble gases, and stable isotopes such ^{18}O and ^{14}C.

Some commenters supported the use of tracers in Class VI injection wells, maintaining that tracers are a useful method for detecting CO_2 leaks. Many commenters suggested that tracers should not be required, but should be allowed at the discretion of the Director. Other commenters thought that owners or operators should be allowed to decide whether to use tracers.

Most commenters asserted that tracers were unnecessary and that better methods for tracking CO_2 movement were available. These commenters cited a variety of reasons, including that tracers were expensive, burdensome, and untested; that detection of a tracer at the surface would do nothing to protect USDWs from endangerment; and that some tracers may have health risks or can contribute to climate change. EPA received comments on specific tracers, such as perfluorocarbons (which have been proven in other applications), radioactive tracers (which have been used successfully in the oil and gas industry, but only with a limited radius), and the use of CO_2 itself (which can act as a tracer).

EPA agrees that tracers can be a useful tool in some circumstances, but recognizes that some factors (*e.g.,* the potential to contribute GHGs to the atmosphere, cost, and difficulties associated with monitoring for tracers) may make other methods of tracking CO_2 movement more practical. Therefore, today's rule does not require use of tracers for Class VI wells. However, EPA does believe that tracers may be valuable in some cases, and will retain Director's discretion to require the use of tracers and to determine the type of tracer to be used if the Director determines that their use will increase USDW protection from endangerment.

F. Testing and Monitoring

Today's final rule at § 146.90 requires owners or operators of Class VI wells to develop and implement a comprehensive testing and monitoring plan for their projects that includes injectate monitoring, corrosion monitoring of the well's tubular, mechanical, and cement components, pressure fall-off testing, ground water quality monitoring, CO_2 plume and pressure front tracking, and, at the Director's discretion, surface air and soil gas monitoring (SDWA section 1421 *et al.*). The rule also requires MIT to verify proper well construction, operation, and maintenance.

Monitoring associated with injection projects is an important component of the UIC program and is required to ensure that USDWs are not endangered. Monitoring data can be used to verify that the injectate is safely confined in the target formation, minimize costs, maintain the efficiency of the storage operation, confirm that injection zone pressure changes follow predictions, and serve as inputs for AoR modeling. Monitoring results will provide information about site performance when compared against baseline information (collected during the site characterization phase) or when compared to previous monitoring results. In conjunction with careful site selection and AoR delineation, monitoring is critical to the successful operation, PISC, and site closure of a GS project.

Today's monitoring requirements are based on existing UIC regulations, tailored to address the needs and challenges posed by GS projects. For example, supercritical CO_2 is different from many Class I injectates in physical properties and chemical composition. Also, many GS projects are anticipated to be "large-scale," with large volumes of CO_2 injected over long project life-spans. In the proposed rule, EPA sought comment on the testing and monitoring plan, MIT, the use of pressure fall-off testing, the types and amounts of ground water quality monitoring, pressure front tracking, geophysical methods, and surface air and soil gas monitoring.

The testing and monitoring requirements for Class VI wells at § 146.90 incorporate elements of pre-existing UIC requirements for monitoring and testing, tailored and augmented as appropriate for GS projects. EPA recognizes that much will be learned about monitoring and testing technologies and their application in various geologic settings in the early phases of GS deployment. Therefore, the Agency will evaluate monitoring data from early GS projects as part of the Agency's adaptive rulemaking approach (See section II.F). The Agency is developing guidance to support testing and monitoring at GS sites.

1. Testing and Monitoring Plan

EPA proposed that owners or operators of Class VI wells submit monitoring plans with their permit applications. These plans would be tailored to the GS project and be implemented upon Director approval, and, at a minimum, include procedures and frequencies for analysis of the chemical and physical characteristics of the CO_2 stream; MIT (internal and external); corrosion monitoring; determination of the position of the CO_2 plume and area of elevated pressure; monitoring of geochemical changes in the subsurface; and, at the discretion of the Director, surface air and soil gas monitoring for CO_2 fluctuations, and any additional tests necessary to ensure USDW protection from endangerment.

EPA sought comment on the testing and monitoring plan. Commenters recommended that the plan be reevaluated concurrently with AoR reevaluations. Commenters agreed that the plan should be site-specific and flexible to allow the use of varied monitoring and testing technologies. The Agency acknowledges the importance of flexibility and today's rule maintains a testing and monitoring plan requirement that will allow for site specificity and selection of the most appropriate monitoring technologies. The Agency also acknowledges the importance of agreement between site-characterization data, AoR information, and monitoring and testing information.

The final rule retains the requirement to develop and implement a testing and monitoring plan and requires that the approved plan be incorporated into the Class VI permit. Owners or operators must also periodically review the testing and monitoring plan to incorporate operational and monitoring data and the most recent AoR reevaluation (§ 146.90(j)). This review must take place within one year of an AoR reevaluation, following significant changes to the facility, or when required by the Director. The iterative process by which this and other required plans are reviewed throughout the life of a project will promote an ongoing dialogue between the owner or operator and the Director. Tying the plan reviews to the AoR reevaluation frequency is appropriate to ensure that reviews of the plans are conducted on a defined schedule to address situations where there is a change in the AoR or other circumstances change, while adding little burden if the AoR reevaluation confirms that the plan is appropriate as written. The Agency is developing guidance that describes the contents of the project plans required in the GS rule, including the testing and monitoring plan.

2. CO_2 Stream Analysis

Injectate analysis provides information on the chemical composition and physical characteristics of the injectate. Analysis of the CO_2 stream for GS projects will provide information about any impurities that may be present and whether such impurities might alter the corrosivity of the injectate down-hole. Such information is necessary to inform well construction and the project-specific testing and monitoring plan, and enable the owner or operator to optimize well operating parameters while ensuring compliance with the Class VI permit. The proposed rule required that analysis of the CO_2 stream be conducted prior to commencing injection and throughout injection operations at an appropriate frequency based on the CO_2 source and the likelihood of variability in the injectate composition. Commenters supported the need for analysis of the CO_2 stream. The final rule retains the requirement that owners or operators need to characterize their CO_2 stream as part of their UIC permit application (§ 146.82(a)(7)), and throughout the operational life of the injection facility (§ 146.90(a)). The details of the sampling process and frequency must be described in the Director-approved, site/project-specific testing and monitoring plan.

Resource Conservation and Recovery Act (RCRA) Applicability to CO_2 Streams: EPA received public comment asserting that the proposed UIC Class VI requirements were unclear as to whether the CO_2 stream would be a RCRA hazardous waste, and left uncertain the type of permit needed. Many commenters stated that a CO_2 stream should not be treated as a RCRA hazardous waste on the grounds that it is neither a listed hazardous waste nor does it exhibit a hazardous characteristic. Other commenters asserted that CO_2 in the presence of water could exhibit the RCRA corrosivity characteristic. Additionally, commenters indicated that analytic procedures used under RCRA (in particular, the toxicity characteristic leaching procedure (TCLP)) cannot be applied to supercritical CO_2 streams and that the Class VI regulations would better ensure the proper management of a CO_2 injectate. EPA did not receive any new data on CO_2 stream characterization in the public comments.

In general, subtitle C of RCRA establishes a "cradle to grave" regulatory scheme over certain "solid wastes" which are also "hazardous wastes." RCRA defines solid waste as, among other things, discarded material, including solid, liquid, semisolid, or contained gaseous material. EPA has further defined the term solid waste for purposes of its hazardous waste regulations. To be considered a hazardous waste, a material must first be classified as a solid waste under the regulations (40 CFR 261.2). Under EPA's regulations at 40 CFR 262.11, generators of solid waste are required to determine whether their wastes are hazardous wastes. A solid waste is a hazardous waste if it exhibits any of four characteristics of a hazardous waste (*i.e.,* ignitability, corrosivity, reactivity, or toxicity) under 40 CFR 261.20–.24, or is a listed waste under 40 CFR 261.30–.33 (these include various used chemical products, by-products from specific industries, or unused commercial products).

A CO_2 stream is not itself a listed RCRA hazardous waste. EPA has reviewed estimates of CO_2 injectate quality, which were based upon information such as the quality of flue gas from the burning of fossil fuels, existing flue gas emission controls (*e.g.,* electrostatic precipitators and scrubbers), and data from applied CO_2 capture technology. These estimates indicate that captured CO_2 could contain some impurities. These estimates also indicate that the types of impurities and their concentrations would likely vary by facility, coal composition, plant operating conditions, and pollutant removal and carbon capture technologies.

Under this final rule, owners or operators will need to determine whether the CO_2 stream is hazardous under EPA's RCRA regulations, and if so, any injection of the CO_2 stream may only occur in a Class I hazardous waste injection well. Conversely, Class VI wells cannot be used for the co-injection of RCRA hazardous wastes (*i.e.,* hazardous wastes that are injected along with the CO_2 stream).

EPA supports the use of CO_2 capture technologies that minimize impurities in the CO_2 stream. As a result of the public comments received on the proposed Class VI rule related to various RCRA applicability issues, EPA initiated a rulemaking separate from today's final UIC Class VI rule. The RCRA proposed rule will examine the issue of RCRA applicability to CO_2 streams being geologically sequestered, including the possible option of a conditional exemption from the RCRA requirements for CO_2 GS in Class VI wells (see RIN 2050–AG60, EPA Semiannual Regulatory Agenda, Spring 2010, EPA–230–Z–10–001). EPA will consider comments received on the Class VI rule during the development of the RCRA proposal. The Agency clarifies that commenters who wish to submit comments on the RCRA proposal must do so during the comment period for that rule. Today's rule does not itself change applicable RCRA regulations.

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) Applicability to CO_2 Streams: EPA received a range of comments regarding CERCLA liability and GS. Some commenters suggested that the Agency allow for a GS exemption under CERCLA, while others requested that the rule specify that injectate intrusion into a USDW is not considered a CERCLA release and that the SDWA provides enough civil and criminal enforcement authority to address any environmental contamination that might result from GS. Other commenters supported maximizing protection under CERCLA by writing Class VI GS permits as broadly as possible so that "unauthorized releases" are avoided.

CERCLA, more commonly known as Superfund, is the law that provides broad Federal authority to clean up releases or threatened releases of hazardous substances that may endanger human health or the environment. CERCLA references four other environmental laws to designate more than 800 substances as hazardous and to identify many more as potentially hazardous due to their characteristics pursuant to RCRA. CERCLA authorizes EPA to clean up sites contaminated with hazardous substances and seek compensation from responsible parties or compel responsible parties to perform cleanups themselves.

CO_2 itself is not listed as a hazardous substance under CERCLA. However, the CO_2 stream may contain a listed hazardous substance (such as mercury) or may mobilize substances in the subsurface that could react with ground water to produce listed hazardous substances (such as sulfuric acid). Whether such substances may result in CERCLA liability from a GS facility depends entirely on the composition of the specific CO_2 stream and the environmental media in which it is stored (*e.g.,* soil or ground water). CERCLA exempts from liability under CERCLA section 107, 42 U.S.C. 9607, certain "Federally permitted releases" (FPR) as defined in CERCLA, 42 U.S.C. 9601(10), which would include the permitted injectate stream as long as it is injected and behaves in accordance with the permit requirements. Class VI permits will need to be carefully structured to ensure that they prevent potential releases from the well, which are outside the scope of the Class VI permit and thus not considered federally permitted releases.

The UIC program Director has authority under the SDWA to address potential compliance issues (*e.g.,* potential releases that may endanger USDWs) resulting from injection violations in the unlikely event that an emergency or remedial response (at § 146.94) is necessary. Although EPA anticipates that the need for emergency or remedial actions at GS sites will be rare, today's rule requires that emergency and remedial response plans be developed and updated to address such events (in accordance with the remedial response requirements at § 146.94) and that owners or operators demonstrate that financial resources are set aside to implement the plans if necessary (pursuant to the financial responsibility requirements at § 146.85).

3. Mechanical Integrity Testing (MIT)

Injection well MIT is a critical component of the UIC program's requirements designed to ensure USDW protection from endangerment. Testing and monitoring the integrity of an injection well at an appropriate frequency throughout the injection operation, in conjunction with corrosion monitoring of well materials, can verify that the injection system is operating as intended or provide notice that there may be a loss of containment that may lead to endangerment of USDWs. Routine MITs enable owners or operators to ensure that well integrity is maintained from construction throughout the life of the injection project. UIC regulations for other deep-well classes require injection well owners or operators to demonstrate both internal and external mechanical integrity.

Internal MIT: Internal mechanical integrity (MI) is an absence of significant leakage in the injection tubing, casing, or packer. Loss of internal MI is usually due to corrosion or mechanical failure of the injection well's tubular and mechanical components. Typically, internal MI is demonstrated with an annual pressure test of the annular space between the injection tubing and long-string casing.

For Class VI wells, EPA proposed that owners or operators perform an initial annulus pressure test and then continuously monitor injection pressure, injection rate, injected volume, pressure on the annulus between the tubing and long-stem casing, and annulus fluid during injection. EPA sought comment on the appropriate frequency of internal MIT and the practicality of continuous testing to measure internal MI. Commenters' suggestions on the appropriate frequency varied and some believed that the proposed requirement for continuous monitoring seemed excessive and/or impractical.

Today's rule at § 146.89 retains the requirements for continuous monitoring to demonstrate internal MI presented in the proposed rule. This is driven by concerns that the potential corrosivity of CO_2 in the presence of water and the anticipated high pressures and volumes of injectate could compromise the integrity of the well. Continuous monitoring to demonstrate internal MI for Class VI wells is essential because it allows for the immediate identification of corrosion-related mechanical integrity problems or problems due to temperature and pressure effects associated with injection of supercritical CO_2. Furthermore, the technologies used for continuous monitoring are currently available and widely used.

External MIT: External well MI is demonstrated by establishing the absence of significant fluid movement along the outside of the casing, generally between the cement and the well structure, and between the cement and the well-bore. Failure of an external MIT can indicate improper cementing or degradation of the cement that was emplaced to fill and seal the annular space between the outside of the casing and the well-bore. This type of failure can lead to movement of injected fluids out of intended injection zones and toward USDWs.

EPA proposed annual external MIT using a tracer survey, a temperature or noise log, a casing inspection log, or any other test the Director requires. EPA sought comment on the appropriate frequency and types of MITs for Class VI wells. In general, commenters requested flexibility in methods and timing of testing, with some suggesting a five-year frequency for external MIT.

Because GS is a new technology and there are a number of unknowns associated with the long-term effects of injecting large volumes of CO_2, today's rule requires owners or operators of CO_2 injection wells to demonstrate external MI at least once annually during injection operations using a tracer survey or a temperature or noise log (§ 146.89(c)). This increase in required testing frequency relative to other injection well classes ensures the protection of USDWs from endangerment given the potential corrosive effects of CO_2 (in the presence of water) on well components (steel casing and cement) and the buoyant nature of supercritical CO_2 relative to formation brines, which could enable it to migrate up a compromised wellbore. The Director may also authorize an alternate test of external mechanical integrity with the approval of EPA (§ 146.89(e)).

In addition, the final rule is modified from the proposal to allow the Director discretion to require use of casing inspection logs to determine the presence or absence of any casing corrosion at § 146.89(d). To ensure the appropriate application of this test and to afford flexibility to owners or operators and Directors, the final rule requires that the frequency of this test be established based on site-specific and well-specific conditions and incorporated into the testing and monitoring plan if the Director requires such testing. This modification is made to clarify that such logs, while not used to directly assess mechanical integrity, may be used to measure for corrosion of the long-string casing and thus may serve as a useful predictor of potential mechanical integrity problems in the future.

4. Corrosion Monitoring

Existing UIC Class I deep well operating requirements allow the Director discretion to require corrosion monitoring and control where corrosive fluids are injected. Corrosion monitoring can provide early warning of well material corrosion that could compromise the well's MI. Given the potential for corrosion of well components if they are in contact with water saturated with CO_2 or CO_2 in the presence of water, corrosion monitoring is included as a routine part of Class VI well testing. EPA proposed quarterly monitoring using coupons, routing the CO_2 injectate through a loop of well material, or an alternative method proposed by the Director.

Some commenters believed that such testing was unnecessary given that well materials will need to be constructed with materials compatible with the injectate. EPA notes, however, that the long-term effects of CO_2 on cement and other well components are not yet completely understood. Given the anticipated long life-span of a Class VI well and the difficulties that would be associated with a corrosion-related well failure, EPA believes that quarterly corrosion monitoring is justified and retains the requirement in the final rule (at § 146.90(c)).

5. Ground Water/Geochemical Monitoring

Ground water and geochemical monitoring are important monitoring techniques that ensure protection of USDWs from endangerment, preserve water quality, and allow for timely detection of any leakage of CO_2 or displaced formation fluids out of the target formation and/or through the confining layer. Periodically analyzing ground water quality (*e.g.,* salinity, pH, and aqueous and pure-phase CO_2) above the confining layer can reveal geochemical changes that result from leaching or mobilization of heavy metals and organic compounds, or fluid displacement.

EPA proposed periodic monitoring of the ground water quality and geochemical changes above the confining zone and sought comment on the types and frequencies of monitoring to be performed. The Agency agrees with commenters who support a flexible monitoring regime, and believes that the amounts and types of monitoring should be site specific.

Some commenters expressed concern that monitoring wells penetrating the confining layer could become conduits for fluid movement. EPA clarifies that direct geochemical monitoring is not required in the target formation itself, although sampling via wells in the target formation may be desirable in some circumstances, *e.g.,* to perform geochemical monitoring in wells used for direct pressure monitoring to meet requirements of § 146.90(g). Furthermore, EPA believes that the benefits of direct monitoring using wells outweigh the risks of unintended fluid migration. Monitoring wells provide important information that confirms injectate confinement. Careful siting and appropriate construction of monitoring wells are critical to effective monitoring and can minimize the potential that monitoring wells serve as conduits for fluid movement.

The final rule, at § 146.90(d), retains the requirement for direct ground water quality monitoring as specified in the site-specific monitoring plan. Such monitoring is required above the confining zone (and below the lower confining zone for waivered wells pursuant to requirements at § 146.95(f)). The number, placement, and depth of monitoring wells will be site-specific and will be based on information collected during baseline site characterization. Ground water and geochemical monitoring results, when compared to baseline site characterization data, previous monitoring results, and operational parameters will enable owners or operators and Directors to assess project performance, confirm that the injectate, formation fluids, and the injection operation are not impacting overlying (and underlying, for wells operating under injection depth waivers) formations, identify formation fluid changes, inform modifications to the monitoring plan, and ensure USDW protection from endangerment.

6. Pressure Fall-Off Testing

Pressure fall-off tests are designed to determine if reservoir pressures are tracking predicted pressures and modeling inputs. The results of pressure fall-off tests will confirm site characterization information, inform AoR reevaluations, and verify that projects are operating properly and the injection zone is responding as predicted.

EPA proposed that owners or operators perform pressure fall-off testing at least once every five years and requested comment on the use and frequency of these tests. Some commenters expressed support for the tests, and suggested frequencies of annually to every five years. Some commenters expressed opposition to the tests stating that they are not necessary and the information they provide is not unique and may be obtained from other tests.

The Agency believes that pressure fall-off testing provides valuable information and that a five-year frequency is appropriate. The final rule, at § 146.90(f), retains the requirement for testing at least once every five years. EPA believes that this frequency will allow for pressure tracking in the injection formation. It will also help to verify that the operation is responding as modeled/predicted and allow the owner or operator to take appropriate action (*e.g.,* recalibration of the AoR model) in the event that the monitoring results do not match expectations.

7. CO_2 Plume and Pressure Front Monitoring/Tracking

Monitoring the movement of the CO_2 and the pressure front are necessary to identify potential risks to USDWs posed by injection activities, verify predictions of plume movement, provide inputs for modeling, identify needed corrective actions, and target other monitoring activities. The proposed rule required tracking of the plume and pressure front by direct pressure monitoring via monitoring wells in the first formation overlying the confining zone or by using indirect geophysical techniques such as seismic profiling, electrical, gravity, and electromagnetic surveys.

EPA sought comment on the requirement to track the CO_2 plume and pressure front and the appropriate technologies and geophysical methods that can be used for such monitoring. Commenters focused on appropriate testing frequency and technologies, expressing concerns about cost and the belief that the requirements were too stringent and might negatively affect public opinion. With respect to direct monitoring of pressure, some commenters supported the proposed approach, while others believed the use of monitoring wells would be costly and difficult. Some commenters supported indirect (*i.e.,* geophysical) monitoring of the plume, while others expressed concerns that seismic methods may not be effective in all settings.

In consideration of all public comments, today's final rule at § 146.90 requires Class VI well owners or operators to perform monitoring to track the extent of the CO_2 plume and pressure front. The owner or operator must use direct methods to monitor for pressure changes in the injection zone. Indirect methods (*e.g.,* seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools) are required unless the Director determines, based on site-specific geology that such methods are not appropriate (§ 146.90(g)).

The purpose of monitoring in the injection zone (§ 146.90(g)(1)) is to track the development and movement of the pressure front and CO_2 plume. This will support an understanding of site performance and verify predictive modeling. Pressure monitoring within the injection zone is necessary because any such monitoring above the confining zone would not detect movement of the pressure front unless a breach of the confining zone occurs. EPA believes that monitoring using wells in the injection zone (*i.e.,* that penetrate the confining zone) can be safely performed if the wells are constructed to prevent flow between the injection zone and USDWs or other layers above the confining zone. Such construction technologies exist and have been used in the oil and gas industry for years. EPA believes that the benefits of monitoring in the injection formation outweigh the manageable risk of those monitoring wells serving as conduits for fluid movement. EPA adds that owners or operators may consider performing additional pressure monitoring in wells that are above the confining zone (*e.g.,* in the same wells used to perform ground water quality monitoring required at § 146.90(d)) to provide additional verification that no pressure changes are occurring above the confining zone due to CO_2 leakage or displacement of native fluids. An appropriate monitoring regimen will enhance public confidence in GS. EPA disagrees that the use of monitoring wells to track the plume and pressure front will be too costly and believes that the benefits outweigh the costs.

Additionally, § 146.90(g)(2) requires owners or operators to track the position of the CO_2 plume using indirect methods (*e.g.,* seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools), unless the Director determines based on site-specific geology, that such methods are not appropriate. EPA is affording Director's discretion regarding the use of geophysical techniques at some sites because the Agency recognizes that geophysical methods are not appropriate in all geologic settings. For example, geophysical methods are difficult to execute in areas that are structurally and topographically complex or where lithologies have limited contrast in density, porosity, permeability, and other physical properties. EPA clarifies that this determination will be made by the Director based on the site-specific geologic information submitted by the owner or operator with their permit application. However, because the use of geophysical methods can yield valuable information about the extent of the CO_2 plume and pressure front, EPA is requiring their use unless they are determined not to be appropriate.

EPA believes that this approach—requiring direct pressure monitoring at all sites and the use of indirect geophysical or down-hole techniques except where the Director determines that such methods are not appropriate based on site-specific information—provides owners or operators the flexibility to develop a site-specific monitoring plan, ensures that direct monitoring is available to track the movement of the CO_2 and validate models, and recognizes that indirect techniques may not be appropriate in all situations.

8. Surface Air/Soil Gas Monitoring

EPA proposed that Directors have discretion to require surface air and/or soil gas monitoring at GS sites. Surface air and soil gas monitoring can be used to monitor the flux of CO_2 out of the subsurface, with elevation of CO_2 levels above background levels indicating potential leakage and USDW endangerment. While deep subsurface well monitoring forms the primary basis for detecting threats to USDWs, knowledge of leaks to shallow USDWs is of critical importance because these USDWs are more likely to serve public water supplies than deeper formations. If leakage to a USDW should occur, near-surface and surface monitoring may assist owners or operators in identifying the general location of the leak and what USDWs may have been impacted by the leak, and initiating targeted emergency and remedial response actions.

EPA sought comment on the use of surface air and soil gas monitoring technologies to ensure USDW protection. Commenters that supported the use of surface air and soil gas monitoring technologies stressed the importance of USDW protection and noted that this monitoring can provide a potential indication that a leak into a USDW has occurred and may need to be remediated. These commenters suggested that such monitoring should be site-specific and that any data collected must be compared against baseline data (collected prior to commencing an injection project). Those who opposed the proposed surface air and soil gas monitoring requirements questioned the applicability of surface air and soil gas technologies to USDW protection, and expressed concerns about the potential for false positives, uncertainty and variability in measurements, and the negative impact that this requirement may have on public perception of GS. Some commenters also believed that requiring such monitoring would be outside the scope of SDWA authority.

The Agency agrees that surface air and soil gas monitoring, when coupled with subsurface monitoring, may be appropriate at some GS projects to ensure USDW protection and agrees that baseline information is needed for this type of monitoring. EPA also acknowledges that surface air and soil gas measurements are subject to variability and may not be suitable for all settings as a method to ensure USDW protection. However, EPA does not believe that this should entirely preclude their use. The decision to use surface monitoring and the selection of monitoring methods will be site-specific (*e.g.,* may be influenced by geology; injection depth; and operational conditions) and must be based on potential risks to USDWs within the AoR. EPA also believes that appropriately selected surface monitoring technologies will not negatively influence public opinion, but could help to assure the public that GS projects are being appropriately operated and monitored. Used in conjunction with deep subsurface monitoring, as required at § 146.90, and as part of a multi-barrier approach to protecting USDWs from endangerment, surface air and soil gas monitoring are within the scope of SDWA's general authority (SDWA sections 1421 *et al.*). Furthermore, where deployed, such monitoring will increase USDW protection, enable immediate notification of the UIC Director in the case of potential USDW endangerment, and facilitate remedial action.

The final rule at § 146.90(h) retains the allowance for surface air and soil gas monitoring at the discretion of the Director as a means of identifying leaks that may pose a risk to USDWs and informing emergency notification of a Class VI owner or operator and UIC Director in the event of a USDW endangerment, pursuant to requirements at § 146.91(c).

Since proposal of the Class VI UIC requirements (73 FR 43492, July 25, 2008), EPA proposed, and is finalizing concurrently with this rulemaking, GS reporting requirements under the GHG Reporting Program (subpart RR). Subpart RR is being promulgated under authority of the CAA and builds on UIC requirements with the additional goals of verifying the amount of CO_2 sequestered and collecting data on any CO_2 surface emissions. If a Director requires surface air/soil gas monitoring pursuant to requirements at § 146.90(h) and an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of subpart RR meets the requirements at § 146.90(h)(3), the Director must approve the use of monitoring employed under subpart RR.

The Agency recognizes that there may be unique circumstances wherein the UIC Director requires the use of surface air/soil gas monitoring other than monitoring deployed under subpart RR due to site-specific considerations. For example, a UIC Director may identify a sensitive USDW such as a sole source aquifer, as defined at 40 CFR part 149, in the AoR of a GS project. He or she may determine that the most appropriate method of enhancing protection of such resources is to require the owner or operator to deploy an array of soil gas probes, pursuant to § 146.90(h), around the sole source aquifer at specified depths and lateral spacing, with specified sampling and reporting frequencies, to ensure USDW protection. Such monitoring might not be necessary under subpart RR, where the primary purpose of surface air and soil gas monitoring is to verify the amount of CO_2 sequestered and collect data on any CO_2 surface emissions.

EPA believes that the requirements of these two rules complement one another by concurrently ensuring USDW protection, as appropriate, and requiring reporting of CO_2 surface emissions under subpart RR. Subpart RR is discussed further in section II.C.

9. Additional Requirements

EPA recognizes that monitoring and testing technologies used at GS sites will vary and be project-specific, influenced by both geologic conditions and project characteristics. At certain sites additional monitoring may be needed. Furthermore, EPA acknowledges that the science and technology behind subsurface monitoring and testing will continue to develop, and new methods may emerge to provide additional monitoring options. Therefore, the final rule (at § 146.90(i)) allows the Director discretion to require additional monitoring where appropriate. For example, a Director may require a Class VI owner or operator to conduct ground water quality monitoring in additional formations or zones or require the use of multiple indirect geophysical methods for plume and pressure front tracking if he or she determines it is necessary based on review of project-specific information submitted.

The final rule, at § 146.90(k), requires owners or operators to submit a quality assurance and surveillance plan (QASP) for all testing and monitoring requirements. A QASP ensures that all aspects of monitoring and testing are verifiable, including the technologies, methodologies, frequencies, and procedures involved. Each QASP will be unique to a given GS project, informed by site-specific details, monitoring technologies selected, and will be updated as the project evolves in concert with the testing and monitoring plan.

G. Recordkeeping and Reporting

Pursuant to § 1445(a)(1) of the SDWA, today's final rule at § 146.91 requires owners or operators of Class VI wells to submit the results of required periodic testing and monitoring associated with the GS project. Furthermore, today's rule at § 146.91(e) also requires that all required reports, submittals, and notifications under subpart H be submitted to EPA in an electronic format. This requirement applies to owners or operators in Class VI primacy States and those in States where EPA implements the Class VI program, pursuant to § 147.1. All Directors will have access to the data through the EPA electronic data system.

EPA expects that the Class VI permit application process will be an iterative process, during which the owner or operator must submit information to the Director to inform permitting decisions and permit issuance. During this process, the Director is responsible for reviewing and approving the required information. The Agency is requiring that owners or operators submit information in an electronic format to facilitate accessibility and transferability; however, if an owner or operator cannot submit the required data using EPA's electronic reporting system, EPA expects the Director to seek EPA's approval regarding an alternate reporting format. Following EPA's approval of a non-electronic submittal format, an alternate reporting procedure may be allowed.

The electronic reporting requirement is designed to facilitate programmatic activities by providing Directors with information needed to ensure compliance with UIC Class VI permits, while also ensuring that GS projects are operating properly, are in compliance with their permit conditions, and are sufficiently protective of USDWs. The information compiled under § 146.91 may be used as evidence of a permit violation.

Use of EPA's electronic reporting system will also allow EPA to access data related to Class VI program implementation and facilitate coordination between EPA and co-regulators. EPA plans to use the data and information submitted by owners or operators to periodically evaluate the effectiveness of the GS program, enabling the Agency to make changes to the Class VI program as necessary to incorporate new research, data, and information about GS and associated technologies.

1. What information must be provided by the owner or operator?

Today's rule identifies the technical information and reports that Class VI owners or operators must submit to the Director to obtain a Class VI permit to construct, operate, monitor, and close a Class VI well. The information submitted as a demonstration, to the Director, must be in the appropriate format and level of detail necessary to support permitting and project-specific decisions by the Director to ensure USDW protection. The final decision regarding the appropriateness and acceptability of all owner or operator submissions rests with the Director.

Class VI Permit Application Information: Today's rule requires owners or operators to submit, pursuant to the requirements at § 146.91(e), information to the Director to support Class VI permit applications (this information is enumerated at § 146.82). This information includes site characterization information on the stratigraphy, geologic structure, and hydrogeologic properties of the site; a demonstration that the applicant has met financial responsibility requirements; proposed construction, operating, and testing procedures; and AoR/corrective action, testing and monitoring, well plugging, PISC and site closure, and emergency and remedial response plans. The specific requirements for the content of this information are discussed in other sections of this preamble.

Operational and Monitoring Reports: Today's rule, at § 146.91, requires owners or operators to submit project monitoring and operational data at varying intervals, including semi-annually and prior to or following specific events (*e.g.,* 30-day notifications and 24-hour emergency notifications).

EPA proposed that operating data be reported semi-annually. EPA also proposed that monitoring data be submitted semi-annually in certain circumstances. Several commenters asked that the Director have discretion to authorize reporting less frequently than semi-annually, while other commenters suggested monthly or quarterly reporting. EPA is retaining the semi-annual reporting requirement for operating data and some monitoring data in the final rule (§ 146.91(a)). However, permitting authorities may choose to require more frequent reporting.

The final rule also requires owners or operators to report the results of mechanical integrity tests, any other injection well testing required by the Director, and any well workovers within 30 days (§ 146.91(b)), as proposed.

Today's final rule consolidates notification requirements and clarifies the manner in which the data must be reported. Owners or operators must notify the Director in writing 30 days prior to any planned well workover, stimulation, or test of the injection well (§ 146.91(d)). This notification affords the Director an opportunity to evaluate the planned activity in the context of new information received since permit approval and correspond with the owner or operator, if necessary, regarding any suggested modifications to the planned activity or to place additional conditions on the planned activity if necessary. EPA clarifies that a response by the Director following 30-day notification is not required if the Director has no further concerns regarding the activity. The final rule also requires owners or operators to notify the Director within 24 hours of obtaining any evidence that the injected CO_2 stream and associated pressure front may cause an endangerment to a USDW, any noncompliance with a permit condition, or of an event (such as malfunction of the injection system or triggering of a down-hole automatic shut-off system) that may endanger USDWs, or any release of carbon dioxide to the atmosphere or biosphere detected through any required soil/air monitoring (§ 146.91(c)).

Area of review reevaluations and plan amendments: Today's final rule requires owners or operators to electronically submit AoR reevaluation information and all plan amendments, pursuant to § 146.84, at a minimum of every five years.

Annual report: In addition to the recordkeeping and reporting requirements, EPA sought comment on requiring submittal of an annual report throughout the duration of a GS project. Most commenters did not support annual reports.

Today's final rule does not include a requirement for an annual report. EPA recognizes the concerns expressed by commenters about the burden associated with an annual report, and believes that the reporting required at § 146.91(a) in conjunction with the AoR reevaluations and associated plan updates, which are required no less frequently than every five years, will facilitate a continuous dialogue between owners or operators and the permitting authority, provide evidence of compliance with the Class VI permit, and ensure protection to USDWs.

2. How must information be submitted?

Electronic Reporting: Recognizing that much of the data generated during Class VI site characterization, operation, testing and monitoring, mechanical integrity testing, and during the post-injection site care period will be generated in electronic format, EPA proposed that owners or operators report data in an electronic format acceptable to the Director (§ 146.91). EPA also proposed that the Director have discretion to accept data in other formats, if appropriate. EPA sought comment on electronic data submissions and the concept of providing Directors discretion to accept other data formats. See section II.C for additional information on mandatory reporting of greenhouse gases under the Clean Air Act.

Most commenters supported the concept of requiring data to be submitted electronically. Commenters also recognized that there may be a need to accept data in other formats. Several commenters expressed concern about whether States would have the capabilities to accept electronic data submissions from owners or operators.

In light of the prevalent use of electronic data, the expectation that Class VI wells will be used into the future, that the capability to send and receive electronic data will improve over time, and that today, information generated during GS site characterization, operation, monitoring, and testing is generated in electronic formats, the final rule requires that owners or operators submit data in an electronic format.

Acknowledging that some States may have to develop electronic data systems to receive electronic information from the owner or operator, and that many States which already have electronic data systems will have to make changes to accommodate a new class of UIC well (Class VI), EPA believes that it is prudent to provide assistance by developing a central framework for the electronic system that will be used by States to gather and track owner or operator data. This will enable owners or operators to submit data without having to wait for a State to develop a system. It will also provide for standardized submissions across the country and enable States to focus State resources on reviewing and approving permit applications rather than building or upgrading separate, independent databases for GS information.

EPA recognizes that there may be some circumstances where it may be necessary to collect data in other formats, *e.g.,* for historical data, etc. Therefore, the Agency is providing for the Director to allow submission of data in alternative formats on a case-by-case basis. EPA expects that decisions to allow submission of data in formats other than electronic will be based on the inability or inefficiency of converting data to electronic formats, rather than the ability of the State to accept electronic data.

3. What are the recordkeeping requirements under this rule?

Today's final rule requires that owners or operators retain most operational monitoring data as required under § 146.91 for 10 years after the data are collected. In addition, the rule requires that owners or operators retain certain data until 10 years after site closure. This recordkeeping timeframe, which is longer than requirements for other injection well classes, is appropriate and tailored to the longer life-spans of GS projects.

The proposed rule did not include any requirements for operational data recordkeeping. However, existing UIC requirements at 40 CFR 144.51(j), which apply to all permitted injection wells require retention of certain operational data and permit application data for three years and retention of injectate quality data throughout the life of the project and for three years after injection well plugging. Commenters requested clarity on the recordkeeping requirements for Class VI well owners or operators, particularly related to well plugging and site closure reports.

Today's final rule clarifies the recordkeeping requirements for Class VI well owners or operators. These include the requirements at 40 CFR 144.51(j) and the Class VI-specific recordkeeping requirements in today's rule at § 146.91(f). Class VI well owners or operators must retain data collected to support permit applications and data on the CO_2 stream until 10 years after site closure. Owners or operators must retain monitoring data collected under the testing and monitoring requirements at § 146.90(b–i) for 10 years after it is collected. Today's rule allows the Director authority to require the owner or operator to retain specific operational monitoring data for a longer duration of time (§ 146.91(f)(5)). Well plugging reports, PISC data, and site closure reports must be kept for 10 years after site closure (§§ 146.92(d), 146.93(f), and 146.93(h)).

EPA believes that longer record retention timeframes are appropriate for Class VI wells to ensure that all necessary data are available to support AoR reevaluations, updates to the various plans which will occur at least every five years, and non-endangerment demonstrations during PISC. In addition, extended retention periods will ensure that data are available should any project-specific questions or concerns arise following site closure. These data will also support EPA's review of project data as part of the adaptive rulemaking approach.

Class VI compliance: Today's final Class VI rule includes requirements for permitting, siting, construction, operation, financial responsibility, testing and monitoring, PISC, and site closure of Class VI injection wells to ensure that USDWs are not endangered. Site-specific information collected during the site characterization process and periodically updated throughout the life of the project is incorporated into the GS project plans and used to establish permit conditions. This information establishes the manner in which an owner or operator must construct, operate, monitor, report on, and close a Class VI GS project—the conditions the owner or operator must meet to ensure compliance. Pursuant to requirements at 40 CFR 144.8, an owner or operator's failure to comply with the site-specific permit conditions, failure to complete construction elements, failure to complete or provide compliance schedules or monitoring reports, failure to submit complete reports, and any action that causes USDW endangerment during the life of the GS project are considered instances of noncompliance and will result in a violation of the permit under SDWA section 1423. Additionally, EPA may use this information as evidence of an imminent and substantial endangerment of a USDW, which may require remedial action under SDWA section 1431.

Data and information gathered through information requests, semi-annual and 30-day reporting, and other project records will provide information to demonstrate and confirm that a Class VI project is in compliance. Information reported within 24 hours as required under § 146.91(c), including, but not limited to: Evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW; triggering of a shut-off system; or failure to maintain mechanical integrity is used to inform the Director of any evidence indicating that an owner or operator of a Class VI well has violated a permit condition or caused endangerment to USDWs.

H. Well Plugging, Post-Injection Site Care (PISC), and Site Closure

Today's final action, at § 146.92 requires owners or operators of Class VI wells to plug injection and monitoring wells in a manner that protects USDWs. The final rule, at § 146.93, also contains tailored requirements for extended, comprehensive post-injection monitoring and site care of GS projects following cessation of injection until it can be demonstrated that movement of the CO_2 plume and pressure front no longer pose a risk of endangerment to USDWs.

Proper plugging of injection and monitoring wells is a long-standing requirement in the UIC program designed to ensure that injection wells do not serve as conduits for fluid movement following cessation of injection and site closure in order to ensure protection of USDWs. PISC, which is unique to GS, is necessary to ensure that site monitoring continues until the injectate and any mobilized fluids do not pose a risk to USDWs.

1. Injection Well Plugging

EPA proposed that, after injection ceases at a GS project, the injection well must be plugged in order to ensure that the well itself does not become a conduit for fluid movement into USDWs. Well plugging activities include flushing the well with a buffer fluid, testing the external mechanical integrity of the well, and emplacing cement into the well in a manner that will prevent fluid movement that may endanger USDWs. In the proposed rule, EPA did not specify the types of materials or tests that must be used during well plugging, acknowledging that there are a variety of methods that are appropriate and new materials and tests may become available in the future. However, all plugging materials must be compatible with the injectate (*i.e.,* such that plugging materials would not degrade over time). EPA sought comment on the injection well plugging activities identified in the proposed rule.

Most commenters supported EPA's proposed approach regarding well plugging. Because the injection well plugging requirements provide appropriate protection of USDWs while allowing owners or operators flexibility in meeting the well plugging requirements by allowing them to choose from available materials and tests to carry out the requirements, EPA retains the requirements as proposed in today's rule at § 146.92. The owners or operators must prepare and comply with a Director-approved injection well plugging plan submitted with their permit application (§ 146.92(b)). The approved injection well plugging plan will be incorporated into the Class VI permit. The Agency is developing guidance that describes the contents of the project plans required in the GS rule, including the injection well plugging plan.

Owners or operators must submit a notice of intent to plug at least 60 days prior to plugging the well. At this time, if any changes have been made to the original well plugging plan (*e.g.,* based on operational and monitoring data or data collected during AoR reevaluations), the owner or operator must submit a revised injection well plugging plan (§ 146.92(c)). Any amendments to the injection well plugging plan must be incorporated into the permit following public notice and comment and approval by the Director. EPA envisions that owners or operators will take into account similar considerations that guide updates to other project plans, *e.g.,* the testing and monitoring plan, as they update the injection well plugging plan. However, EPA is not requiring formal periodic review and updates to the injection well plugging plan throughout the injection phase because it is not expected that changes to this plan will be implemented until the point at which the injection well is to be plugged. EPA also encourages an ongoing dialogue between owners or operators and Directors regarding planned well plugging activities. Finally, owners or operators must submit, to the Director, a plugging report within 60 days after plugging. The Agency is developing guidance on injection well plugging, PISC, and site closure that addresses performing well plugging activities.

2. Post-Injection Site Care (PISC)

Today's final rule at § 146.93 incorporates a PISC period, specific to Class VI wells. PISC is the period after CO_2 injection ceases—but prior to site closure—during which the owner or operator must continue monitoring to ensure USDW protection from endangerment.

PISC and site closure plan submittal and updates: EPA proposed that owners or operators would prepare, update, and comply with a Director-approved PISC and site closure plan that would describe the anticipated PISC monitoring activities and frequency.

EPA sought comment on the PISC and site closure plan requirements. Most commenters supported the requirement for PISC monitoring and the proposed approach regarding submittal, revision, and implementation of a PISC and site closure plan. Many commenters agreed that a PISC monitoring plan is a necessary and important part of the permitting process. These commenters supported the option to amend the plan. However, they contended that, upon cessation of injection, if evaluation of monitoring and modeling results indicates that the project is performing as expected, an owner or operator should not have to submit amendments to the plan.

Today's final regulation retains the PISC and site closure plan requirements (§ 146.93) with an additional requirement at § 146.93(a)(2)(v) that the owner or operator include the duration of the PISC timeframe, and the demonstration of any alternative PISC timeframe pursuant to requirements at § 146.93(c) as part of the plan. The requirement to maintain and implement the approved PISC and site closure plan is directly enforceable regardless of whether the requirement is a condition of the Class VI permit. The PISC and site closure plan will serve to clarify PISC requirements and procedures prior to commencement of a project.

Upon cessation of injection, today's rule requires that owners or operators of Class VI wells either submit an amended PISC and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed (§ 146.93(a)(3)). Any amendments to the PISC and site closure plan would be incorporated into the permit once they are approved by the Director. EPA envisions that owners or operators would take into account similar considerations that guide updates to other project plans, *e.g.,* the testing and monitoring plan, as they update the PISC and site closure plan. EPA also encourages an ongoing dialogue between owners or operators and Directors regarding planned PISC and site closure activities. The Agency is developing guidance that describes the content of the project plans required in the GS rule, including the PISC and site closure plan.

PISC timeframe: EPA proposed that during PISC, owners or operators of Class VI wells would be required to periodically monitor the site and track the position of the CO_2 plume and pressure front to ensure USDWs are not endangered. The proposed rule identified a default PISC timeframe of 50 years following the cessation of injection. This timeframe was based on a review of research studies, industry reports, and existing environmental programs. In order to support site-specific flexibility, the proposed rule stipulated that the PISC timeframe could be shortened by the Director after cessation of injection if the owner or operator could demonstrate that USDWs would not be endangered prior to 50 years. Similarly, if after 50 years the Director determined that USDWs may still become endangered by the CO_2 plume and/or pressure front, he or she could lengthen the PISC timeframe. EPA sought comment on the proposed PISC timeframe and whether the timeframe should be adjusted.

Most industry commenters supported reducing the default PISC timeframe, stating that the 50-year default timeframe in the proposal would make GS prohibitively expensive, and is not warranted based on the probable timeframes of CO_2 trapping. Commenters suggested that the PISC timeframe should be specific to the characteristics of a project, including the predicted extent of the CO_2 plume and the area of elevated pressure, geologic factors, modeled predictions of CO_2 trapping, and subsurface geochemical reactions and that the PISC period be established on a case-by-case basis as a part of the permitting process. Other commenters supported the proposed 50-year PISC period and indicated that the risks of GS to USDWs are still unclear, and thus a conservative PISC monitoring time period should be implemented. Other commenters asserted that a combination of a fixed timeframe and a performance standard would strike a good balance and is preferable to relying on only one approach.

EPA evaluated comments advocating for a shorter timeframe, including suggestions of 10 and 30 years. However, EPA has not obtained any data from commenters or identified other research that contradict EPA's initial analysis and supports a default timeframe shorter than 50 years. EPA acknowledges the merits of a performance-based approach for the PISC timeframe, recognizing the variety of site conditions that will affect the appropriate PISC timeframe. EPA believes that the Director will be in the best position to make a site-specific determination allowing for the PISC timeframe to be modified while ensuring USDWs are not endangered.

Therefore, in response to comments, EPA retains the proposed default 50-year PISC timeframe. However, today's final rule affords flexibility regarding the duration of the PISC timeframe by: (1) Allowing the Director discretion to shorten or lengthen the PISC timeframe during the PISC period based on site-specific data, pursuant to requirements at § 146.93(b); and, (2) affording the Director discretion to approve a Class VI well owner or operator to demonstrate, based on substantial data during the permitting process, that an alternative PISC timeframe is appropriate if it ensures non-endangerment of USDWs pursuant to requirements at § 146.93(c).

EPA clarifies that owners or operators of all GS sites (*i.e.,* those commencing injection using the 50-year default PISC or those demonstrating an alternative PISC timeframe pursuant to requirements at § 146.93(c)) must continue monitoring until they submit, for Director review and approval, a demonstration based on monitoring and other site-specific data that no additional monitoring is needed to ensure that the GS project does not pose an endangerment to USDWs. If a demonstration cannot be made that the GS project no longer poses a risk of endangerment to USDWs, or the Director does not approve the demonstration, the owner or operator must submit a plan to the Director to continue post-injection site care until such a demonstration can be made and approved by the Director.

Today's final rule at § 146.93(c), affords the Director discretion to approve a demonstration during the permitting process (per requirements at § 146.82(a)(18)) that an alternative post-injection site care timeframe, other than the 50-year default, is appropriate. The demonstration must be based on substantial evidence and site-specific data and information compiled and analyzed during the permitting process and must satisfy the Director, in consultation with EPA that USDWs will be protected from endangerment from GS activities.

Today's final rule at § 146.93(c)(1) specifies what the Director, in consultation with EPA, must consider and what the demonstration of an alternative PISC timeframe must be based on: The results of site-specific computational modeling of the AoR (performed pursuant to § 146.84) and information that supports the PISC and site closure plan development required at § 146.93(a), including the predicted timeframe for pressure decline within the injection zone and any other zones; the predicted rate of CO_2 plume migration and timeframe for the cessation of migration; site-specific chemical processes that will result in CO_2 trapping (*e.g.,* by capillary trapping, dissolution, and mineralization); the predicted rate of CO_2 trapping; and laboratory analyses, research studies, and/or field or site-specific studies to verify the information on trapping. The demonstration must also be based on consideration and documentation of a characterization of the confining zone(s), *e.g.,* thickness, integrity, and the absence of transmissive faults, fractures, and micro-fractures (based on information collected per § 146.82(a)(3)); the presence of potential conduits for fluid movement near the injection well (per § 146.84(c)(2)); the quality of wells and well plugs in wells within the AoR (per § 146.84(c)(3)); the distance between the injection zone and the nearest USDWs above and/or below the injection zone (based on data collected per § 146.82(a)(5)); and any additional site-specific factors required by the Director.

The demonstration of an alternative PISC timeframe must meet criteria set forth at § 146.93(c)(2) to ensure that the data and models on which the demonstration is based are accurate, appropriate to site-specific circumstances, based on the best available information, calibrated where sufficient data are available, and reproducible. This demonstration must be submitted as part of the permit application pursuant to § 146.82(a)(18); the duration of the alternative PISC timeframe and the associated demonstration must be included in the PISC and site closure plan pursuant to § 146.93(a)(2)(iv); and, must be incorporated in the permit as part of the PISC and site closure plan as required at § 146.82(c)(9).

Over the lifetime of the project, owners or operators must periodically reevaluate the AoR regardless of the PISC timeframe approved by the Director. This may also result in periodic reevaluations and updates as needed to the PISC and site closure plan (per § 146.93(a)(4)). These reevaluations provide opportunities for the owner or operator and the Director to review and validate the data on which the alternative demonstration is based, along with operational and monitoring data, to determine whether modifications to the alternative PISC timeframe are needed, and to make changes to the PISC plan as appropriate. Regardless of whether the PISC and site closure plan is modified during the injection period or not, the rule requires at § 146.93(a)(3) that upon cessation of injection, owners or operators must either submit an amended plan or demonstration to the Director through monitoring data and modeling results that no amendment to the plan is needed.

Today's final rule also retains the proposed approach affording the Director discretion, during the PISC period, to shorten the PISC timeframe if the owners or operators can demonstrate that there is substantial evidence that the GS project no longer poses a risk of endangerment to USDWs (§ 146.93(b)). Likewise, the Director may lengthen the PISC timeframe if, after 50 years, USDWs still may become endangered.

EPA believes that a default post-injection site care timeframe of 50 years, with flexibility to adjust the timeframe during the permitting process where substantial data exists to demonstrate that an alternative timeframe would be protective of USDWs, or based on data collected during the PISC period, is appropriate to address the range of sites where GS is anticipated to occur, to accommodate site-specific circumstances and various geologic conditions, and addresses commenters' concerns, while ensuring USDW protection. The Agency is developing guidance on injection well plugging, PISC, and site closure.

3. Site Closure

EPA proposed that, following a determination under § 146.93 that the site no longer poses a risk of endangerment to USDWs, the Director would approve site closure and the owner or operator would be required to properly close site operations. EPA proposed site closure activities similar to those for other well classes. These include plugging all monitoring wells; submitting a site closure report; and recording a notation on the deed to the facility property or other documents that the land has been used to sequester CO_2. Site closure would proceed according to the approved PISC and site closure plan. Today's final regulation retains these closure requirements (at § 146.93(d) through (h)).

The site closure report will provide documentation of injection and monitoring well plugging; copies of notifications to State and local authorities that may have authority over future drilling activities in the region; and records reflecting the nature, composition, and volume of the injected CO_2 stream. The purpose of this report will be to provide information to potential, future users and authorities of the land surface and subsurface pore space regarding the operation. Well plugging reports, PISC data, including, if appropriate, data and information used to develop the alternative PISC timeframe, and site closure reports must be kept for 10 years after site closure (or longer at the Director's discretion), pursuant to the requirements at §§ 146.91(f),146.93(f), and 146.93(h). See section III.G for more about the recordkeeping requirements in today's rule.

I. Financial Responsibility

Today's rule finalizes regulations at § 146.85 to require that owners or operators demonstrate and maintain financial responsibility as approved by the Director for performing corrective action on wells in the AoR, injection well plugging, PISC and site closure, and emergency and remedial response.

The purpose of these financial responsibility requirements is to ensure that owners or operators have the resources to carry out activities related to closing and remediating GS sites if needed during injection or after wells are plugged but before site closure is approved so that they do not endanger USDWs. The end result is ensuring that all the GS injection sites are cared for and maintained appropriately and that there is no gap in coverage throughout injection and post-injection site care and site closure.

EPA's Proposed Approach: Financial assurance for wells under the UIC program is typically demonstrated through two broad categories of financial instruments: (1) Third party instruments, including surety bond, financial guarantee bond or performance bond, letters of credit (the above third party instruments must also establish a standby trust fund), and an irrevocable trust fund; and (2) self-insurance instruments, including the corporate financial test and the corporate guarantee. In the preamble to the proposed rule, EPA described these instruments and sought comment on the need to adjust financial responsibility instruments for GS projects and the need for additional financial responsibility instruments. The Agency also sought comment on allowing separate financial demonstrations for injection well plugging and PISC (*i.e.,* a demonstration submitted prior to well plugging and the beginning of the post-injection site care period rather than with the permit application).

Summary of Public Comments and Other Input: Commenters identified strengths and weaknesses of the various financial responsibility instruments and expressed concerns about the risk of bank failures and corporate insolvency, which could leave financial obligations unfunded. Some commenters supported the use of self insurance (*i.e.,* a financial test and a corporate guarantee) as a mechanism to demonstrate financial responsibility for GS projects, but expressed concerns that companies that have passed financial tests can fail, and also that the current tangible net worth requirement of $10 million is not adequate for GS projects. Generally, commenters supported allowing separate financial demonstrations for injection well plugging and PISC. Many commenters expressed concern about the potential high cost and long time frames involved with GS projects. They believed that financial assurance would be difficult to obtain, particularly throughout the duration of the PISC period and that it may discourage investment in GS.

Commenters also expressed a need for regulatory certainty to help inform financial responsibility requirements for well owners or operators. They suggested that EPA specify the acceptability of various financial responsibility instruments and that States needed guidance including information on what instruments they should approve in order to avoid approving financial assurance that did not meet the Federal requirements or that was financially inadvisable. Other commenters suggested that the proposed rule left too much discretion to the Director, possibly causing operators to run a higher risk of having their instrument rejected. Other commenters suggested that the rule provide flexibility to owners or operators in the choice of financial instruments, while allowing the Director discretion to assess instruments in the context of operational and site-specific factors, including the level of risk over time, when approving financial responsibility for each project.

Many commenters addressed the use of a pay-in period for trust funds. Some commenters expressed concern that an initial three-year pay-in period would increase upfront costs, while others suggested that an initial pay-in period could help lower financial risk. A commenter suggested that the duration of the pay-in period could coincide with the estimated project risk.

In addition to evaluating public comments, EPA worked with members of the public, academia, industry, regulatory agencies, and financial experts to address the unique financial responsibility issues associated with GS projects. In April and May of 2009, EPA held webinars for the public and industry stakeholders to gather information to inform the financial responsibility requirements and guidance. The webinars facilitated information sharing among stakeholders on financial instruments that could be used to meet the financial responsibility requirements for GS projects. Approximately 100 webinar participants, representing a range of organizations with interest in and unique perspectives on financial responsibility, attended the workshop series which focused on the strengths and weaknesses of various financial instruments and their applicability for various injection activities. The material presented during the webinars and summaries of participant discussions can be found in the docket for today's rulemaking.

EPA is also aware of recent published literature on the topic of financial responsibility for GS. In particular, the World Resources Institute (WRI) and CCS Regulatory Project (affiliated with Carnegie Mellon University, Department of Engineering and Public Policy) have published research on climate change technologies and policy issues. These and other resources are informing EPA's financial responsibility guidance. These reports can be found in the docket for today's rulemaking.

To supplement publicly available literature and public comments, EPA reevaluated the current minimum Tangible Net Worth (TNW) requirement of $10 million used in the Class I regulations and will recommend a TNW threshold for Class VI wells in guidance. EPA guidance on TNW for GS will help ensure that the risk borne by the public from a self-insured owner or operator is no greater than the riskiest scenario where independent third-party instruments are used. The financial responsibility guidance will also include a recommended cost estimation methodology to assist owners or operators of Class VI wells. The guidance will provide examples of cost considerations and activities that may need to be performed to satisfy the requirements of today's rule. A draft of this guidance will be posted on EPA's Web site at *http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm* for a 30-day public comment period concurrent with or shortly after publication of today's final rule.

EPA solicited input from the Environmental Financial Advisory Board (EFAB) to develop recommendations on financial responsibility for Class VI wells absent any constraints under the SDWA. EFAB made several recommendations that support the financial responsibility requirements in today's final rule. EFAB agreed that both self insurance and third-party insurance should be made available to responsible parties. They also supported the requirement that third-party providers, such as insurers, pass financial strength requirements, the use of credit ratings to demonstrate financial strength, and that the owner or operator notify the Director in the event of bankruptcy. EFAB also agreed that financial responsibility requirements be linked to cost estimates, with regular updates to both cost estimates and financial responsibility demonstrations. Additionally, EFAB specifically recommended:

- The use of standardized language for financial instruments. Although EFAB did not recommend the use of standardized policy language for insurance, they did suggest that procedures be adopted so that the Director can specifically agree to limitations contained in the insurance policy or specifically reject such limitations during the review process;
- That the owner or operator be required to notify the Director by certified mail of any proceeding under Title 11 (Bankruptcy), U.S. Code, within 10 business days after the commencement of the proceeding; that owners or operators be deemed to not possess the required financial responsibility in the event of bankruptcy, insolvency, or a suspension or revocation of the license or charter of the third party when using letters of credit, surety bonds, or insurance policies or loss of authority of the third party to act as a trustee when using a trust fund;
- That because the RCRA financial mechanisms, which are largely used in the SDWA Class I program, were developed based on hazardous waste facility owner's or operator's considerations, there may be differences in the owner or operator profiles for proposed GS facilities that warrant additional assurance mechanisms. Thus, the Agency should consider adding a new category of financial assurance to the Class VI program that provides the Agency with the flexibility to approve the "functional equivalent" to the established RCRA financial assurance tests; and
- That EPA consider the use of rate-based financing, a new category of instrument that would provide the Director with the flexibility to approve instruments that are functionally equivalent to existing qualifying instruments.

Today's Final Approach: Today's final regulation retains the substantive requirements that owners or operators of Class VI wells demonstrate and maintain financial responsibility to cover the cost of corrective action, injection well plugging, PISC and site closure, and emergency and remedial response. In response to public comments EPA requested in the proposed rule and other input, this final regulation at § 146.85, modifies the proposed requirements to provide clarity on acceptable instruments to enhance enforceability of the requirements, and to set reporting timeframes to provide consistency with other EPA regulations. Specifically, EPA has clarified the financial responsibility requirements by:

(1) Describing "qualifying instruments" to cover the cost of corrective action, injection well plugging, PISC and site closure, and emergency and remedial response in a manner that prevents endangerment of USDWs.

(2) Adding language clarifying that the financial responsibility instrument is directly enforceable regardless of whether the requirement is a condition of the permit.

(3) Requiring submission of annual inflationary updates and specifying a 60-day timeframe after notification by the Director for the submission of written updates of adjustments to the cost estimate.

(4) Requiring owners or operators to notify the Director no later than 10 days after filing for bankruptcy.

(5) Requiring an owner or operator or its guarantor using self insurance to demonstrate financial responsibility for GS to meet a Tangible Net Worth of an amount approved by the Director; have both a net working capital and a tangible net worth of at least six times the sum of the current well plugging, post-injection site care and site closure cost; have assets located in the U.S. amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post-injection site care and site closure cost; submit annual report of bond rating and financial information; and either: (1) Pass a bond rating test issued by one or both of the nationally recognized bond rating agencies, Standard & Poor's and Moody's for which the bond's rating must be one of the four highest categories (*i.e.,* AAA, AA, A, or BBB for Standard & Poor's or Aaa, Aa, A, or Baa for Moody's); or, (2) Meet all of the following five financial ratio thresholds:

- A ratio of total liabilities to net worth less than 2.0;
- A ratio of current assets to current liabilities greater than 1.5;
- A ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1;
- A ratio of current assets minus current liabilities to total assets greater than −0.1; and
- A net profit (revenues minus expenses) greater than 0.

These financial responsibility requirements are not made to duplicate existing financial responsibility regulations, but are tailored to the unique characteristics and requirements of GS. Considering the potential high costs associated with large-scale deployment of GS projects, EPA would like to ensure that adequate and continuous financial responsibility mechanisms are in place throughout the life of each GS project and that the cost associated with operation of GS projects is not passed along to the public. EPA also believes that having stringent self-insurance requirements in addition to an annual evaluation of the financial instrument minimizes the potential for a financial institution (that has passed the test) to be likely to undergo financial difficulties that can hinder the financial responsibility demonstration for a GS project.

EPA's final approach for financial responsibility for Class VI wells: EPA does not have authority under SDWA to be the direct or indirect beneficiary of a trust fund under this statute for the purpose of establishing financial responsibility for GS projects. EPA must comply with the Miscellaneous Receipts Act, 31 U.S.C. 3302. Standby trust funds are not stand-alone financial instruments that can be used by an owner or operator to demonstrate financial responsibility. Standby trusts must be used with certain types of financial responsibility instruments to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. Use of standby trust funds must be accompanied by other financial responsibility instruments (*e.g.,* surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed. The final rule, at § 146.85(a)(1), identifies the following qualifying financial instruments for Class VI wells, all of which must be sufficient to address endangerment of USDWs. Standby trusts are not needed for options 1, 4, and 5.

(1) Trust Funds: If using a trust fund, owners or operators are required to set aside funds with a third party trustee sufficient to cover estimated costs. During the financial responsibility demonstration, the owner or operator may be required to deposit the required amount of money into the trust prior to the start of injection or during the "pay-in period" if authorized by the Director.

(2) Surety Bond: Owners or operators may use a payment surety bond or a performance surety bond to guarantee that financial responsibility will be fulfilled. In case of operator default, a payment surety bond funds a standby trust fund in the amount equal to the face value of the bond and sufficient to cover estimated costs, and a performance surety bond guarantees performance of the specific activity or payment of an amount equivalent to the estimated costs into a standby trust fund.

(3) Letter of Credit: A letter of credit is a credit document, issued by a financial institution, guaranteeing that a specific amount of money will be available to a designated party under certain conditions. In case of operator default, letters of credit fund standby trust funds in an amount sufficient to cover estimated costs.

(4) Insurance: The owner or operator may obtain an insurance policy to cover the estimated costs of GS activities requiring financial responsibility. This insurance policy must be obtained from a third party to decrease the possibility of failure (*i.e.,* non-captive insurer).

(5) Self Insurance (*i.e.,* Financial Test and Corporate Guarantee): Owners or operators may self insure through a financial test provided certain conditions are met. The owner or operator needs to pass a financial test to demonstrate profitability, with a margin sufficient to cover contingencies and unknown obligations, and stability. If the owner or operator meets corporate financial test criteria, this is an indication that the owner or operator can guarantee its ability to satisfy financial obligations based solely on the strength of the company's financial condition. An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.

(6) Escrow Account: Owners or operators may deposit money to an escrow account to cover financial responsibility requirements. This account must segregate funds sufficient to cover estimated costs for GS financial responsibility from other accounts and uses.

(7) Other instrument(s) satisfactory to the Director: In addition to these instruments, EPA anticipates that new instruments that may be tailored to meet GS needs may emerge, and may be determined appropriate for use by the Director for the purpose of financial responsibility demonstrations.

The final rule specifies that the qualifying financial responsibility instrument must include protective conditions of coverage, including, but not limited to: Cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable in case of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum credit rating, minimum capitalization, and ability to pass the bond rating when applicable. This clarification was made in direct response to issues raised by commenters for numerous instruments, and also to make sure that there is no gap in coverage if a financial instrument fails.

Today's rule, at § 146.85(c), requires the owner or operator to have a detailed written estimate, in current dollars, of the cost of: Performing corrective action on wells in the AoR, plugging the injection well(s), PISC and site closure, and emergency and remedial response. A cost estimate must be prepared separately for each of these activities and be based on the costs to the owner or operator of hiring a third party (who is neither a parent nor a subsidiary of the owner or operator) to perform the activities. EPA recommends that owners or operators take the following into account when determining the cost estimate for GS projects:

(1) Performing corrective action on wells in the AoR. This includes conducting corrective action on deficient wells in the AoR during the initial AoR, under a phased corrective action approach; and for newly-identified deficient wells in subsequent AoR re-evaluations. See section III.B for more details on the AoR and corrective action plan requirements.

(2) Plugging the injection well(s). This includes performing a final external MIT and plugging the wells in a manner that considers the well depth, the number of plugs and the amount of cement needed, the composition of the captured CO_2, and the types of subsurface formations. See section III.H for more details on plugging requirements.

(3) Post-injection site care and closure. This includes all needed monitoring and site care until it can be demonstrated that the site no longer poses an endangerment to USDWs. See section III.H for more details on post-injection site care and site closure requirements.

(4) Emergency and remedial response. This includes the cost to perform any necessary responses or remediation to address potential USDW endangerment. See section III.J for more details on the emergency and remedial response requirements.

Owners or operators have the flexibility to choose from a variety of financial instruments to meet their financial responsibility obligations. Owners or operators may use one or multiple financial responsibility instruments for well plugging and PISC (§ 146.85(a)(6)). However, EPA will not allow for a separate financial responsibility demonstration for well plugging and PISC (*i.e.,* a demonstration submitted prior to well plugging and the beginning of the PISC period rather than with the permit application). A demonstration of financial responsibility for all phases of the GS project will be required prior to the issuance of a Class VI permit (§ 146.85(a)(5)(i)).

EPA adds that under today's final rulemaking at § 146.85(a), the Director will only approve instruments determined to be sufficient to address endangerment of USDWs, and has the discretion to disapprove of instruments that he/she determines may not be sufficient based on the following:

(1) The financial instrument is not determined to be a qualifying instrument;

(2) The financial instrument is not sufficient to cover the cost to properly plug and abandon, remediate, and manage wells;

(3) The financial instrument is not sufficient to address endangerment of USDWs; or

(4) The financial instrument does not include required conditions of coverage to facilitate enforceability and prevent gaps in coverage for the life of the GS project.

EPA has added language, at § 146.85(b), that a financial responsibility instrument is directly enforceable regardless of whether the requirement is a condition of the permit. EPA also specifies circumstances under which an owner or operator may be released from a financial instrument, including that the owner or operator has completed the GS project activity for which the financial instrument was required and has fulfilled all financial obligations as determined by the Director, or has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument. The Director's determination of completion of a GS project activity may be sustained by a professional engineer's report on completion. The Director must notify the owner or operator in writing that the owner or operator is no longer required to maintain financial responsibility for the project or activity. This clarification was added to address unforeseen situations where EPA may need to directly enforce the financial responsibility provisions should the permit inadequately provide protection of USDWs from endangerment.

This rule, at § 146.85(c), also requires that the owner or operator adjust the cost estimates to address amendments to the AoR and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the PISC and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94). Within 60 days after the Director has approved any modifications to the plan(s), the owner or operator must review and update the cost estimate for well plugging, PISC and site closure, and emergency and remedial response to account for any amendments if the change in the plan increases the cost. The revised cost estimate must also be adjusted for inflation as specified at § 146.85(c)(2). Any changes to the approved cost estimate must be approved by the Director.

Today's rule does not allow a separate demonstration for financial responsibility requirements (*i.e.,* a demonstration submitted prior to well plugging and the beginning of the post-injection site care period rather than with the permit application). Although the owner or operator may use a financial instrument or a combination of financial instruments for the purpose of financial responsibility for specific phases of the GS project, the demonstration of financial responsibility must be done for the overall GS project at the time of permit application. However, today's rule, at § 146.85(a)(6) provides that, prior to obtaining a Class VI permit, an owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific GS activities, thereby realizing greater flexibility and cost savings from this regulation. In the event that the owner or operator combines more than one instrument for a specific GS activity (*e.g.,* well plugging), such combination must be limited to instruments that are not based on financial strength or performance (*i.e.,* self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of instruments, rather than the single instrument, which must provide financial responsibility for an amount at least equal to the current cost estimate. EPA also notes that today's rule requires the Director to approve the use and length of pay-in-periods for trust funds or escrow accounts. EPA understands that in some cases a short pay-in period (*e.g.,* three-years or less) will provide some financial flexibility for owners or operators while balancing financial risk.

EPA has further clarified financial responsibility requirements by requiring owners or operators or a guarantor to notify the Director no later than 10 days after filing for bankruptcy, at § 146.85(d). This requirement is added in direct response to commenters who addressed the necessity of adequate financial responsibility requirements, even in the event of operator bankruptcy. EPA is adding this requirement in order to avoid a gap in coverage in the event that an instrument fails. This timeframe is consistent with the current U.S. bankruptcy code. In the event that the third party files for bankruptcy, today's rule requires that the owner or operator establish alternative financial assurance within sixty (60) days.

Today's rule, at § 146.85(e), also requires the owner or operator to adjust cost estimates if the Director has reason to believe that the most recent demonstration is no longer adequate to cover the cost of the identified activities. This clarification is made in direct response to commenters who stressed the importance of accurate cost estimates. The Agency is developing guidance, which will provide direction to the Director for when a demonstration may no longer be adequate to cover the GS activities.

As a Federal agency, EPA is working to create a nationally consistent financial responsibility program for GS activities while providing permitting authorities an appropriate level of flexibility. EPA is developing guidance on financial responsibility for owners or operators of Class VI wells to assist owners or operators in evaluating the financial responsibility requirements for Class VI wells and to assist Directors in evaluating financial responsibility demonstrations. The guidance will describe financial responsibility options, demonstrations, types of financial instruments for Class VI wells as well as how to estimate the costs to support accurate financial responsibility demonstrations specific to the needs of a GS project.

Long-term liability and stewardship for GS projects under the SDWA: EPA received a range of comments from stakeholders regarding liability following site closure. Many commenters suggested that, after a GS site is closed, liability should be transferred to the State or Federal government or to a publicly- or industry-funded entity based on a series of rationales (*e.g.,* the need for certainty; the potential for high cost; insurance and legal concerns). EPA also received comments from those who disagreed with the assertion that a public entity should bear liability following site closure based on the belief that, if owners or operators face potential liability following site closure, they would use precaution in their operations to avoid risks and potential environmental damage. Additionally, many commenters encouraged EPA to consider other State or Federal laws under which liability transfers may be accomplished as models for GS liability transfer.

Under SDWA authority, owners or operators of injection wells must ensure protection of USDWs from endangerment and are subject to liability for enforcement under the Act. The final rule requires that an owner or operator must conduct monitoring as specified in the Director-approved PISC and site closure plan following the cessation of injection until the owner or operator can demonstrate to the Director that the geologic sequestration project no longer poses an endangerment to USDWs. For additional information about the PISC and site closure requirements, see section III.H of this action.

Once an owner or operator has met all regulatory requirements under part 146 for Class VI wells and the Director has approved site closure pursuant to requirements at § 146.93, the owner or operator will generally no longer be subject to enforcement under section 1423 of SDWA for noncompliance with UIC regulatory requirements. However, an owner or operator may be held liable for regulatory noncompliance under certain circumstances even after site closure is approved under § 146.93, under section 1423 of the SDWA for violating § 144.12, such as where the owner or operator provided erroneous data to support approval of site closure.

Additionally, an owner or operator may always be subject to an order the Administrator deems necessary to protect the health of persons under section 1431 of the SDWA after site closure if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW. For example, the Administrator may issue a SDWA section 1431 order if a well may present an imminent and substantial endangerment to the health of persons, and the State and local authorities have not acted to protect the health of such persons. The order may include commencing a civil action for appropriate relief. If the owner or operator fails to comply with the order, they may be subject to a civil penalty for each day in which such violation occur or failure to comply continues.

Furthermore, after site closure, an owner or operator may, depending on the fact scenario, remain liable under tort and other remedies, or under other Statutes including, but not limited to, Clean Air Act, 42 U.S.C. §§ 7401–7671; CERCLA, 42 U.S.C. § 9601–9675; and RCRA, 42 U.S.C. 6901–6992.

EPA acknowledges stakeholder interest in liability and long-term stewardship in the context of development and deployment of GS technology, however, under current SDWA provisions EPA does not have authority to transfer liability from one entity (*i.e.,* owner or operator) to another.

J. Emergency and Remedial Response

Today's rule at § 146.94 requires Class VI well owners or operators to develop and maintain an 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. Owners or operators must also periodically update the emergency and remedial response plan to incorporate changes to the AoR or other significant changes to the project. Today's requirements will support expeditious and appropriate response to protect USDWs from endangerment in the unlikely event of an emergency.

Developing emergency and remedial response plans: EPA proposed that owners or operators submit an emergency and remedial response plan to the Director as part of the Class VI permit application. The plan would describe measures that would be taken in the event of adverse conditions at the well, such as a loss of mechanical integrity, the opening of faults or fractures within the AoR, or if movement of injection or formation fluids caused an endangerment to a USDW. Commenters were supportive of including an emergency and remedial response plan as part of the Class VI permit, and some commenters suggested that the plan should be risk based. EPA agrees that advanced planning for emergency and remedial response is an important part of ensuring protection of USDWs at GS sites from endangerment, and today's rule retains the requirement for an emergency and remedial response plan (§ 146.94(a)), and also requires that the approved emergency and remedial response plan be incorporated into the Class VI permit. The purpose of the emergency and remedial response plan is to ensure that owners or operators comprehensively plan, in advance, what actions would be necessary in the unlikely event of an emergency. The plan will also ensure that operators know what entities and individuals must be notified and what actions might need to be taken to expeditiously mitigate any emergency situations and protect USDWs from endangerment. The Agency is developing guidance that describes the contents of the project plans required in the GS rule, including the emergency and remedial response plan. The docket for today's rulemaking includes brief research papers that discuss remedial technologies available to address potential impacts of CO_2 on water resources (USEPA, 2010b) and remedial technologies that may be used to seal faults and fractures at GS sites (USEPA, 2010c).

EPA agrees with commenters that the emergency and remedial response plan should be site-specific and "risk-based." EPA expects that each emergency and remedial response plan will be tailored to the site, and today's rule provides flexibility to the owner or operator to design a site-specific plan that meets the requirements of § 146.94(a). Rather than requiring specific information in the emergency and remedial response plan that may not be relevant to all GS projects, the plan allows such information to be determined on a site-specific basis. The details of an emergency and remedial response plan may be influenced by a variety of factors including: Geology, USDW depth, and injection depth; the presence, depth, and age of artificial penetrations; proposed operating conditions and properties of the CO_2; and activities in the AoR (*e.g.,* the presence of population centers, land uses, and public water supplies). The Director will evaluate the proposed emergency and remedial response plan for a GS project in the context of all information submitted with the permit application (*e.g.,* site characterization information, AoR evaluation data, and well construction, monitoring, and operational information) to ensure that the plan is appropriately comprehensive to address potential emergencies.

Implementing the emergency and remedial response plan: EPA also proposed several steps that the owner or operator would need to follow if he or she obtained evidence that the injectate and associated pressure front may endanger a USDW. Most comments requesting clarity on this requirement recommended that EPA establish triggers during the initial permitting phase and identify appropriate mitigation options.

EPA disagrees with commenters that it is appropriate or useful to identify specific triggers or response actions in the rule that would apply to all sites.

EPA believes that decisions about responses should be made through consultation between owners or operators and Directors because each response action will be site- and event-specific. The purpose of the emergency and remedial response requirements in today's rule is to ensure that a plan is in place for the owner or operator to take appropriate action (*e.g.,* cease injection) in the unlikely event of an emergency or USDW endangerment. The plan also facilitates a dialogue between the owner or operator and the Director to expedite the necessary and appropriate response based on steps identified in advance.

Today's rule at § 146.94(b) requires that, if an owner or operator obtains evidence of endangerment to a USDW, he or she must: (1) Immediately cease injection; (2) take all steps reasonably necessary to identify and characterize any release; (3) notify the Director within 24 hours; and, (4) implement the approved emergency and remedial response plan.

Emergency and remedial response plan updates: Two water associations recommended that the emergency and remedial response plan be reviewed and updated throughout the course of a GS project. EPA agrees with these commenters and today's rule includes a requirement that owners or operators must periodically review the emergency and remedial response plan to incorporate operational and monitoring data and the most recent AoR reevaluation at § 146.94(d). This review must take place within one year of an AoR reevaluation, following significant changes to the facility, or when required by the Director. The iterative process by which this and other required plans are reviewed throughout the life of a project will promote an ongoing dialogue between owners or operators and Directors and ensure that owners or operators are complying with the conditions of their Class VI permits. Tying emergency and remedial response plan reviews to the AoR reevaluation frequency is appropriate to ensure that reviews of the plans are conducted on a defined schedule that ensures there will be appropriate revisions to the plan if there is a change in the AoR or other relevant circumstances change, while adding little burden if the AoR reevaluation confirms that the plan is appropriate as written.

K. Involving the Public in Permitting Decisions

Public input and participation in GS projects has a number of benefits, including: (1) Providing citizens with access to decision-making processes that may affect them; (2) educating the community about a GS project; (3) ensuring that the public receives adequate information about the proposed GS project; and (4) allowing the permitting authority and owners or operators to become aware of public viewpoints, preferences and environmental justice concerns and ensuring these concerns are considered by decision-making officials.

GS of CO_2 is a new technology that is unfamiliar to most people and maximizing the public's understanding of the technology can result in more meaningful public input and constructive participation as new GS projects are proposed and developed. Early and frequent public involvement through education and information exchange is critical to the success of GS and can provide early insight into how the local community and surrounding communities perceive potential environmental, economic, or health effects associated with a specific GS project. Owners or operators can increase the likelihood of success by integrating social, economic, and cultural concerns of the community into the permit decision-making process.

In the proposed rule, EPA sought comment on: (1) The appropriateness of adopting existing public participation requirements at 40 CFR parts 25 and 124 for GS; (2) the need for additional public participation requirements to reflect availability of new information technology to disseminate and gather information; and (3) ways to enhance the public participation process.

Nearly all commenters agreed that early and frequent public education and participation would enhance public acceptance of GS projects. Several commenters supported adopting the existing public participation requirements used for other injection well classes. Many commenters favored requiring the use of new information technology to improve public notification and involvement on GS projects and permitting.

Today's final approach adopts the existing UIC public participation requirements at 40 CFR part 25 and the permitting decision procedures at 40 CFR part 124. EPA encourages owners or operators and permitting agencies to involve the public by providing them information about the Class VI permit (and any requests for a waiver of the injection depth requirements or an expansion of the areal extent of an aquifer exemption) as early in the process as possible. Under 40 CFR parts 25 and 124, permitting authorities must provide public notice of pending actions via newspaper advertisements, postings, mailings, or e-mails to interested parties; hold public hearings if requested; solicit and respond to public comment; and involve a broad range of stakeholders.

EPA expects that there will be higher levels of public interest in GS projects than for other injection activities. The Agency believes that encouraging public participation will help permitting authorities understand public concerns about GS projects and will afford the public an opportunity to gain a clearer understanding of the nature and safety of GS projects and technologies. To address comments about stakeholder participation, EPA is amending the requirements for public notice of permit actions and public comment period at § 124.10 to clarify that public notice of Class VI permitting activities must be given to State and local oil and gas regulatory agencies, State agencies regulating mineral exploration and recovery, the Director of the PWSS program in the State, and all agencies that have jurisdiction to oversee wells in the State in addition to the general public.

EPA agrees with commenters that the use of new forms of information technology can improve public participation and understanding of GS projects. EPA recognizes the importance of social media as a public outreach tool. Social media, which are primarily Internet and mobile based technologies for disseminating and discussing information, can help provide accessibility and transparency to a wide audience. EPA encourages permit applicants and permitting authorities to use the Internet and other forms of social media to explain potential GS projects; describe GS technologies; and post information on the latest developments related to a GS project including schedules for hearings, briefings and other opportunities for involvement.

L. Duration of a Class VI Permit

Today's rule establishes that Class VI permits are issued for the life of the GS project, including the PISC period (§ 144.36). In lieu of the periodic permit reissuance required for most other deep-well classes, owners or operators of Class VI wells must periodically reevaluate the AoR and prepare and implement a series of plans for AoR and corrective action, testing and monitoring, injection well plugging, PISC and site closure, and emergency and remedial response. These plans must be reevaluated by the owner or operator throughout the life of the project to foster a continuing dialogue between the owner or operator and the

Director, and afford opportunities for public input as needed and ensure compliance with the Class VI permit.

EPA proposed that Class VI injection well permits be issued for up to the operating life of the facility, including the PISC period. In the preamble to the proposed rule, EPA explained that, in lieu of permit renewals for Class VI wells, owners or operators must periodically re-evaluate the AoR, at least every 10 years. In existing UIC program regulations, permit duration varies by injection well class: permits for Class I and Class V wells are effective for up to 10 years; while Class II and III permits may be issued for the operating life of the facility, but are subject to a review by the permitting authority at least once every five years.

EPA sought comment on the proposed permit duration for Class VI wells, the appropriateness of GS project plans, and the merits of updating the AoR and corrective action plan in place of permit reissuance. Many commenters supported EPA's proposal to issue permits for the life of a GS project, stating that the requirements for periodic reevaluation of the AoR and corrective action plan would make a five-or ten-year permit review process unnecessary and that a lifetime permit would provide operational continuity. Some commenters suggested that other plans (*e.g.,* the testing and monitoring plan) should also be periodically reviewed throughout the life of the project. Other commenters disagreed with EPA's proposed permit duration for Class VI wells, believing that the proposed level and frequency of interaction (*i.e.,* every 10 years) between the primacy agency and owner or operator would not be sufficient to justify a permit for the operating life of the project. Comments both in favor of and opposition to lifetime permits stressed the importance of incorporating new information, the value of permit review and modification, and the need for a transparent process.

EPA agrees with commenters regarding the need for continuous interaction between permitting authorities and owners or operators of GS projects. Today's rule retains the requirement that Class VI permits are issued for the lifetime of the project (§ 144.36). It also requires owners or operators to review and update the AoR and corrective action plan, the testing and monitoring plan, and the emergency and remedial response plan throughout the life of the project (§ 146.84(e), § 146.90(j), and § 146.94(d)).

Today's rule requires owners or operators to review each plan as required by part 146 and either identify necessary amendments to the plan or demonstrate to the satisfaction of the Director that no amendment is needed. These reviews must be performed within one year of an AoR reevaluation, following any significant changes to the facility (*e.g.,* the addition of monitoring or injection wells), or when required by the Director. In no case can reviews occur less often than once every five years. This review frequency is necessary to ensure that reviews of the plans are conducted on a defined schedule or when there is a change in the AoR or other significant change, while adding little burden if an AoR reevaluation confirms that the plans are appropriate as written. (EPA also revised the AoR reevaluation frequency from 10 years to five years; see section III.B.)

EPA is not requiring formal periodic review and updates to the injection well plugging plan and PISC and site closure plan throughout the injection phase because it is not expected that changes to these plans would be implemented until injection operations cease. However, today's rule at §§ 146.92 and 146.93 does require that owners or operators identify any needed changes to these plans at the cessation of injection operations.

Because the approved plans required by today's rule will be incorporated into the Class VI permit, today's rule establishes permit modification requirements tailored for Class VI permits (*e.g.,* associated with plan updates and other project changes). These requirements state that any changes to the plans will trigger a permit modification pursuant to § 144.39(a)(5).

These modifications invoke part 124 public participation requirements. The Director, through consultation with the owner or operator, may choose to provide public notice of permit modifications as they occur or concurrent with the five year permit review schedule at § 144.36 (*e.g.,* the Director may notice multiple modifications at once, every five years). Minor changes to the plans (*e.g.,* correction of typographical errors) that may result in a permit modification pursuant to requirements at § 144.41 for minor modifications of permits will not require public notification. If any of the plans are changed because of significant changes they will be considered by the Director to be major modifications under § 144.39.

Periodic review and revision of required plans and the ongoing dialogue between owners or operators and Directors will address many of the comments in support of periodic permit renewal, without the associated time and expense of rewriting the entire permit. Instead, today's final approach requires a close level of interaction between owners or operators and Directors. It requires permits to be informed with continually updated information, focuses resources on key issues, and provides for public transparency and involvement when needed. Periodic reevaluation of the AoR, along with reviews and updates to the plans, will provide an equivalent level of review and attention to address potential risks, while focusing time and resources on the most important components of GS operations.

The iterative reviews and revisions of the various rule-required plans and the underlying computational models will also provide numerous opportunities for technical reassessments of the project. These reviews will ensure that the owner or operator and the Director have current knowledge of how the CO_2 plume and pressure front are behaving and afford them time to assess the information and react appropriately to ensure protection of USDWs.

Transfer of permits: Today's final rule does not allow for automatic transfer of a Class VI permit to a new owner or operator (§ 144.38(b)). Given the unique nature of GS and the importance of interaction between GS project owners or operators and permitting authorities, the Agency believes that the Director should have an opportunity to review the permit and determine whether any changes are necessary at the time of the permit transfer, pursuant to requirements at § 144.38(a). If information about the GS project and existing permit conditions are determined to be adequate, the permit review and transfer may entail a minimal amount of new information and administrative effort.

Area permits: Today's rule does not allow area permits for Class VI wells (§ 144.33(a)(5)). Individual well permits are essential to ensure that every Class VI well is constructed, operated, monitored, plugged, and abandoned in a manner that protects USDWs from endangerment. Individual permitting of wells maximizes opportunities for the public to provide input on each well as it is brought into service. This also ensures that existing wells that are converted or re-permitted from other well classes (*e.g.,* Class II EOR/EGR wells converted to Class VI) are engineered and constructed to meet the requirements at § 146.86(a) and ensure protection of USDWs from endangerment in lieu of requirements at § 146.86(b) and § 146.87(a).

While area permits allow for some administrative efficiency, this efficiency can also be achieved through appropriately executed plans for Class VI wells. For example, an owner or operator under § 146.84(c)(1) must delineate the projected lateral and vertical movement of the CO_2 plume and formation fluids from the commencement of injection activities until injection ceases. This delineation should account for any future wells that the owner or operator plans to construct in the AoR to ensure that the Director can consider all anticipated injection and resultant pressure changes when evaluating the plan and setting permit conditions. Similarly, testing and monitoring plans should account for future injection wells to ensure that ground water monitoring and CO_2 plume and pressure front tracking are planned appropriately. Through this iterative planning and submission process, owners or operators and Directors can accomplish multiple efficiencies: permits to construct Class VI wells can be submitted and reviewed either separately or simultaneously, and common, static components of the project can be identified and incorporated into future permit applications, which would facilitate submittal of data by the owner or operator and review and approval by the Director of future wells in the same field.

Owners or operators and permitting authorities may also achieve economies of scale by conducting the public process (*e.g.,* noticing wells; holding hearings) for several Class VI permits simultaneously. This may improve efficiency and public understanding of how multiple wells may interact in a given GS site. EPA also believes that requiring separate permit applications 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.

As part of the EPA's adaptive rulemaking approach, the Agency will collect information on early GS projects and may consider the use of area permits in the future.

IV. Cost Analysis

Today's rulemaking finalizes regulations for the protection of USDWs, but it does not require entities to sequester CO_2. The costs and benefits associated with protection of USDWs from endangerment are the focus of this rule; however, those associated with the mitigation of climate change are not directly attributable to this rulemaking.

To calculate the costs and benefits of compliance for the final GS Rule, EPA selected the existing UIC program Class I industrial waste disposal well category as the baseline for costs and benefits. EPA used this baseline to determine the incremental costs of today's rule, based on the fact that permits issued to early pilot projects included requirements similar to those for Class I industrial wells.

The incremental costs of the rule include elements such as geologic site characterization, well construction and operation, monitoring equipment and procedures, well plugging, and post-injection site care (monitoring). The benefits of this rulemaking include the decreased risk of endangerment to USDWs and potentially a corresponding decrease in health-related risks associated with contaminated USDWs.

The scope of the GS Rule Cost Analysis includes the full range of activities associated with an injection project, from the end of the CO_2 pipeline at the GS site to the underground injection and monitoring, as it occurs during the timeframe of the analysis. The scope of the cost analysis does not include capturing or purifying the CO_2, nor does it include transporting the CO_2 to the GS site. Some costs as highlighted in this section have changed from the proposed rule based on cost updates or public comments received.

The timeframe of the cost analysis was extended from 25 years in the proposed rule to 50 years for the final rule. Although twice as long as the timeframes commonly used in drinking water-related cost analyses, EPA believes that 50 years reflects the fact that the full lifecycle of GS projects is expected to be well beyond 25 years while avoiding the extreme amount of uncertainty involved in projecting an analysis across multiple generations. Costs attributed to this rule are inclusive of GS projects begun during the 50 years of the analysis, and all cost elements that occur during the 50-year timeframe are discounted to present year values. The number of GS projects projected to be implemented over the timeframe of the cost analysis (29) includes pilot projects and other projects associated with regulations that are in place today.[3] EPA consulted directly with DOE and Regional Partnerships and searched publicly available data to inform the estimated number of projects. Again, EPA emphasizes that the rule does not require anyone to undertake GS.

[3] Note that although pilot projects are conducted on a small scale, they are considered geologic sequestration demonstration projects for a given site, not Class V experimental technology well projects.

EPA recognizes that basing the analysis on 29 projects (consisting of pilot projects and other projects) expected on the basis of regulations in place today omits the incremental costs of applying these requirements to additional projects that may result from future changes in climate policy and that a much larger number of affected projects (and thus higher costs) could result from such policy changes. EPA has thus conducted several sensitivity analyses to provide perspective on the incremental costs of the rule under possible future climate policy scenarios. These are summarized in Section IV.A.2.b of this preamble and discussed in greater detail in Cost Analysis for this rule (see EPA, 2010d).

This section of the Preamble summarizes the results of the cost analysis conducted for this rule. For details, see the *Cost Analysis for the Final GS Rule,* which is included in the rule docket.

A. National Benefits and Costs of the Rule[4]

1. National Benefits Summary

This section summarizes the risk (and benefit) tradeoffs between compliance with existing requirements and with the regulatory alternative (RA) selected for the final rule. The Cost Analysis includes a more comprehensive evaluation of risk and benefit tradeoffs for all of the RAs considered for the final rule (see Chapter 2 of the Cost Analysis for a description of each of the RAs). These evaluations in the Cost Analysis include a nonquantitative analysis of the relative risks of contamination to USDWs for the RAs under consideration. The expected change in risk based on promulgation of the selected RA and the potential nonquantified benefits of compliance with this RA are also discussed.

a. Relative Risk Framework—Qualitative Analysis

Table IV–1 below presents the projected directional change in risk of the selected RA relative to the baseline. As detailed in Chapter 5 in the Cost Analysis, the term "baseline" in the exhibit refers to risks as they exist under the current UIC program regulations for Class I industrial wells. The terms "decrease" and "increase" indicates the change in risk relative to this baseline. The Agency has used best professional judgment to qualitatively assess the relative risk associated with each RA.

[4] Although both estimated costs and benefits are discussed in detail, the final policy decisions regarding this rulemaking are not premised solely on a cost/benefit basis.

This assessment was made with contributions from a wide range of injection well and hydrogeological experts, ranging from scientists and well owners or operators to administrators and regulatory experts.

TABLE IV–1—RELATIVE RISK OF REGULATORY COMPONENTS FOR SELECTED RA VERSUS THE CURRENT REGULATIONS [5]

Requirements	Direction of change in risk for selected RA (relative to baseline)
1. Geologic Characterization	
Baseline Identify a geologic system consisting of a receiving zone; trapping mechanism; and confining system to allow injection at planned rates and volumes. Provide maps and cross sections of local and regional geology, AoR, and USDWs; characterize the overburden and subsurface; and provide information on fractures, stress, rock strength, and in-situ fluid pressures within cap rock and storage reservoir. *Incremental Requirements under RA3* Perform detailed assessment of geologic, hydrogeologic, geochemical and geomechanical properties of proposed site. Identify additional zones above the confining zone that will impede vertical fluid movement (at Director's discretion). Collect seismic history data; identify and evaluate faults and fractures.	Decrease.
2. Area of Review (AoR) Study and Corrective Action	
Baseline The AoR determined as either a ¼ mile radius or by mathematical formula. Identify all wells in the AoR that penetrate the injection zone and provide a description of each; identify the status of corrective action for wells in the AoR; and remediate those posing a risk to USDWs. *Incremental Requirements under RA3* Define the AoR using sophisticated computational models based on site specific data that accounts for multiphase flow and the buoyancy of CO_2. Perform corrective action using materials that are compatible with CO_2. Periodically reevaluate the AoR over the life of the injection project.	Decrease.
3. Injection Well Construction	
Baseline The well must be cased and cemented to prevent movement of fluids into or between USDWs and to withstand the injected materials at the anticipated pressure, temperature and other operational conditions. Wells must be constructed to inject below the lowermost USDW. *Incremental Requirements under RA3* Construct and cement wells with casing, tubing, and packer that meet API or ASTM International standards and are compatible with CO_2. Cemented surface casing (base of the lowermost USDW to surface) and long string casing (cemented from injection zone to surface) must be compatible with fluids with which they may be expected to come into contact. (A waiver of the Class VI requirement that projects inject below the lowermost USDW may be permitted in limited cases.)	Decrease (enhanced well construction requirements); Increase (A waiver to inject above the lowermost USDW in limited cases).
4. Well Operation	
Baseline Limit injection pressure to avoid initiating new fractures or propagating existing fractures in the confining zone adjacent to the USDWs. *Incremental Requirements under RA3* Limit injection pressure to less than the fracture pressure of the injection formation in any portion of the area defined by the anticipated pressure front. Equip injection wells with down-hole shut-off systems.	Decrease.
5. Mechanical Integrity Testing (MIT)	
Baseline Demonstrate internal mechanical integrity, and conduct a pressure fall-off test every 5 years *Incremental Requirements under RA3* Continuously monitor injection pressure, flow rate, injected volumes, and pressure on the annulus between the tubing and the long string casing. Demonstrate external mechanical integrity annually, and conduct casing inspection logs at the discretion of the Director.	Decrease.
6. Monitoring	
Baseline Monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics. Conduct ground water monitoring within the AoR (Director's discretion). Report semi-annually on the characteristics of injection fluids, injection pressure, injection flow rate, injection volume and annular pressure, and on the results of MITs and groundwater monitoring.	Decrease.

TABLE IV–1—RELATIVE RISK OF REGULATORY COMPONENTS FOR SELECTED RA VERSUS THE CURRENT REGULATIONS [5]—Continued

Requirements	Direction of change in risk for selected RA (relative to baseline)
Incremental Requirements under RA3 Develop, implement, and periodically review a Testing and Monitoring plan for the site. Monitor injectate; corrosion of the well's tubular, mechanical and cement components. Conduct pressure fall-off testing; CO_2 plume and pressure front tracking; and ground water quality monitoring. Report operating and monitoring results twice per year in operating reports, unless the monthly MIT or other periodic tests revealed operations were somehow compromised, in which case 24 hour notification is required.	
7. Well Plugging and Post-Injection Site Care (PISC)	
Baseline Ensure that the well is in a state of static equilibrium and plugged using approved methods. Plugs shall be tagged and tested. Conduct PISC monitoring to confirm that CO_2 movement is limited to intended zones. *Incremental Requirements under RA3* Flush the well with a buffer fluid, determine bottom-hole reservoir pressure, and perform a final external MIT. Develop and implement a plan to conduct PISC monitoring, (which may include pressure monitoring, geophysical monitoring, and geochemical monitoring in and above the injection zone and the USDW). Following the PISC monitoring (50 years), perform a non-endangerment demonstration to ensure no threat to USDWs and that no further monitoring is necessary.	Decrease.
8. Financial Responsibility	
Baseline Demonstrate and maintain financial responsibility and resources to plug and abandon the injection well *Incremental Requirements under RA3* Demonstrate and maintain financial responsibility for all needed corrective action, emergency and remedial response, and PISC and closure. Adjust the cost estimates for these activities periodically to account for inflation and other conditions that may affect costs.	Decrease.
9. Emergency and Remedial Response	
Baseline No specific requirement under Baseline. *Incremental Requirements under RA3* Develop and periodically review an emergency and remedial response plan that describes actions to be taken to address events that may cause an endangerment to a USDW during construction, operation and PISC.	Decrease.
Overall	Decrease.

[5] The activity baseline used for costing purposes in this analysis is based on the UIC program Class I industrial waste disposal well category because of the similarity of early CO_2 sequestration permits to the permits from that well class.

Note: Chapters 2 and 4 of the GS rule Cost Analysis provide detail on the components of the regulatory alternatives considered in this analysis and on the direction of change in risk associated with them, respectively.

In considering the benefits of the GS rule, the direction of change in risk compared to the baseline regulatory scenario was assessed for each component of the four RAs considered. An overall assessment for each alternative as a whole requires consideration of the relative importance of the risk being mitigated by each component of the rule.

As shown in Table IV–1, EPA estimates that under the selected alternative, RA3, risk will decrease relative to the baseline for each of the nine components assessed.

b. Other Nonquantified Benefits

Finalization of this rule will result in direct benefits, that is, protection of USDWs as is required of EPA under SDWA; and indirect benefits, which are those protections afforded to entities as a by-product of protecting USDWs. Indirect benefits are described in Chapter 4 of the GS Rule Cost Analysis. They include mitigation of potential risk to surface ecology and to human health through exposure to elevated concentrations of CO_2. Potential benefits from any climate change mitigation are not included in the assessment.

2. National Cost Summary

a. Cost of the Selected RA

EPA estimated the incremental one-time, capital, and operations and maintenance (O&M) costs associated with today's rulemaking. As Table IV–2 shows, the total annualized incremental cost associated with the selected RA is $38.1 million (as compared to $15.0 million for the proposed rule) and $31.7 million (as compared to $15.6 million in the proposed rule), using a 3-percent and 7-percent discount rate, respectively. These costs are in addition to the baseline costs that would be incurred if GS activities were instead subject to the current rules for UIC Class I industrial wells. As can be seen from Table IV–2, today's rule increases the costs of complying with UIC regulations for these wells from approximately a baseline total of $70.2 million ($32.3 million in the proposed rule) to $108.3 million ($47.3 million in the proposed rule) in annualized terms using a 3-percent discount rate, which is an increase of 54 percent. EPA believes these increased costs are needed to ensure the protection of UDWSs from endangerment. The details of the costs associated with each RA are presented in the Cost Analysis, along with a discussion of how EPA derived these estimates (EPA, 2010d).

Table IV-2. Annualized Incremental Costs of Selected RA for Initial Baseline[1] of 29 Projects (2008$, $million)[2]

Regulatory Alternative	One-Time Costs	Capital Costs	O&M Costs	Total
	3 Percent Discount Rate			
RA0	$ 10.0	$ 15.5	$ 44.8	$ 70.2
RA3	$ 16.6	$ 21.5	$ 70.2	$ 108.3
RA3 Incremental	$ 6.6	$ 6.0	$ 25.4	$ 38.1
	7 Percent Discount Rate			
RA0	$ 11.2	$ 16.5	$ 30.4	$ 58.1
RA3	$ 18.2	$ 23.5	$ 48.1	$ 89.8
RA3 Incremental	$ 7.0	$ 7.0	$ 17.7	$ 31.7

Notes:

1) Depending on the RA, it is estimated that 25-26 of the 29 baseline projects (25.1 under RA0 and 26.4 under RA3) will successfully deploy over the 50 year period of analysis. Annualized one-time, capital, and O&M costs are based on the number of successfully deployed projects.

2) Detail may not add due to rounding.

Table IV–3 presents a breakout of the annualized incremental costs of the selected RA by rule component using a 3-percent discount rate:

• Monitoring activities account for approximately 49 percent of the incremental regulatory costs. Most of this cost is for the construction, operation, and maintenance of corrosion-resistant monitoring wells. This cost includes tracking of the plume and pressure front as well as the cost of incorporating monitoring results into fluid-flow models that are used to reevaluate the AoR. These activities are a key component of decreasing risk associated with GS because they facilitate early detection of unacceptable movement of CO_2 or formation fluids.

• The next largest cost component of the selected RA is injection well operation, which accounts for approximately 22 percent of the total incremental cost. This component ensures that the wells operate within established parameters in the permit to prevent unacceptable fluid movement.

• Mechanical integrity testing accounts for approximately 6.8 percent of the cost. Continuous pressure monitoring is a key component of decreasing risk because it provides an early warning that a CO_2 leak may have occurred and allows the owner or operator to prevent compromises to well integrity.

• Construction of Class VI wells using the corrosion-resistant design and materials necessary to withstand exposure to CO_2 accounts for approximately 3.2 percent of the incremental cost of the selected RA.

• Geologic site characterization, which ensures that the site geology is safe and appropriate for GS, accounts for approximately 12.1 percent of the incremental cost of the selected RA. Costs for this component were determined using a site selection factor that accounts for the expense of characterizing multiple sites prior to finding an appropriate site.

• Well plugging and post-injection site care activities, which ensure that the injection well is properly closed and that the geologic sequestration project no longer poses a risk to USDWs, account for approximately 5.7 percent of the total incremental cost of RA 3.

• AoR activities, which include modeling the AoR and remediating wells in the AoR, account for approximately 1.0 percent of the total incremental cost of RA3.

Table IV-3. Annualized Incremental Rule Costs of Selected RA for Initial Baseline of 29 Projects by Rule Component (2008$, $million)

Regulatory Alternative	Rule Component									
	Geologic Site Characterization	Monitoring	Injection Well Construction	Area of Review	Well Operation	MIT	Well Plugging and Post-Injection Site Care[1]	Financial Responsibility[2]	Permitting Authority Admin	TOTAL
	3 Percent Discount Rate									
Baseline	$6.7	$3.4	$16.2	$1.1	$41.8	$0.2	$0.6	$0.0	$0.3	$70.2
Alternative 3	$11.3	$22.0	$17.4	$1.5	$50.3	$2.7	$2.8	$0.0	$0.4	$108.3
Alt 3 Incremental	$4.6	$18.6	$1.2	$0.4	$8.5	$2.6	$2.2	$0.0	$0.1	$38.1
Alt 3 as % of Total	12.1%	49%	3.2%	1.0%	22%	6.8%	5.7%	0.0%	0.3%	100%
	7 Percent Discount Rate									
Baseline	$8.3	$2.9	$17.0	$1.0	$28.2	$0.1	$0.2	$0.0	$0.3	$58.1
Alternative 3	$14.1	$18.7	$18.4	$1.3	$34.2	$1.7	$1.0	$0.0	$0.4	$89.8
Alt 3 Incremental	$5.7	$15.8	$1.4	$0.3	$5.9	$1.6	$0.8	$0.0	$0.2	$31.7
Alt 3 as % of Total	18%	50%	4.3%	1.1%	19%	5.1%	2.4%	0.0%	0.5%	100%

Notes:

1) With the exception of the two pilot saline projects in the baseline, the GS Rule Cost Model does not capture the full PISC period for projects under the baseline and RA3, and because these costs mostly occur near (or after) the end of the 50 year period of analysis they are also significantly influenced by the discount rate.

2) Costs related to demonstration of Financial Responsibility are less than $100,000 in annualized terms.

3) Detail may not add due to rounding.

b. Nonquantified Costs and Uncertainties in Cost Estimates

Should this rule somehow impede GS from happening, then the opportunity costs of not capturing the benefits associated with GS could be attributed to this regulation; however, the Agency has tried to develop a rule that balances risk with practicability, site specific flexibility and economic considerations and believes the probability of such impedance is low. This rule ensures protection of USDWs from endangerment associated with GS activities while also providing regulatory certainty to industry and permitting authorities and an increased understanding of GS through public participation and outreach. Thus, EPA believes the rule will not impede GS from happening and has not quantified such risk.

Uncertainties in the analysis are inherent in some of the basic assumptions as well as some detailed cost items. Uncertainties related to economic trends, the future rate of CCS deployment, and GS implementation choices may affect three basic assumptions on which the analysis is based: (1) The estimated number of projects that will be affected by the GS rule; (2) the labor rates applied; and (3) the estimated number of monitoring wells to be constructed per square mile of the AoR to adequately monitor in a given geologic setting.

First, the number of projects that will deploy from 2011 through 2060 may be significantly underestimated in this analysis given the uncertainty in future deployment of this technology. The current baseline assumption is that 29 projects (changed from 22 projects in the proposed rule) will deploy during the 50-year period (changed from 25 years in the proposed rule), as described in Chapter 3 of the Cost Analysis. To address the uncertainty inherent in projecting the GS baseline, the final rule cost analysis also presents sensitivity analyses that considers 5 and 54 projects as the lower and upper bound project numbers to be consistent with the Mandatory Reporting of Greenhouse Gases: injection and Geologic Sequestration of CO_2 rule (subpart RR). EPA developed this rule simultaneously with subpart RR to ensure coordination of requirements and costs between the two rules. The sensitivity analysis numbers (5 and 54 projects) are based on projected deployment highlighted in the presidential memorandum establishing the CCS Task Force and an EPA legislative analysis model of deployment under the American Power Act, respectively.

Second, the labor rate adopted for each of the labor categories for owners or operators described in Section 5.2.1 of the Cost Analysis (*i.e.,* geoscientist, mining and geological engineer) may be underestimated. The labor rates used in the Cost Analysis are based on current industry costs; therefore, the level and pace of price responses as the level of GS deployment increases represents a potentially uncertain component in the cost estimates. The practice of CO_2 injection represents an activity that, although already practiced widely in some contexts (*i.e.,* ER), has the potential to expand rapidly in the coming years. This expansion may be exponential under certain climate legislative scenarios, which may lead to shortages in labor and equipment in the short term and result in rapid cost escalation for many of the cost components discussed in the Cost Analysis. However, based on current research, potential increases in costs due to increased deployment rates and an associated rise in demand for labor or services in the field are not expected to cause a rapid, wide-scale increase in deployment. To address the potential underestimate of labor rates in the event that rapid deployment does drive up costs, EPA conducted sensitivity analyses using labor rates that were 50% higher than those used in the primary analysis. EPA found that the 50% increase in industry labor rates results in annualized incremental rule costs of $38.6 million based on a 3 percent discount rate, an approximately 1% increase in costs from the primary analysis.

Third, for the purpose of estimating national costs, the Agency assumes one monitoring well above the injection zone per two square miles of AoR; for monitoring wells into the injection zone, the Agency assumes one monitoring well per four square miles. EPA assumes monitoring wells into the injection zone will also be used to sample above the injection zone. However, the Agency recognizes that operators and primacy agency Directors may choose more or fewer monitoring wells depending on project site characteristics. Because the monitoring wells and associated costs represent a significant component of the cost analysis, the Agency acknowledges that this factor may be significant in the overall uncertainty of the cost analysis. To address this source of uncertainty, the Agency conducted sensitivity analyses based on alternative estimates of 25 percent more and 25 percent fewer monitoring wells than the number assumed for the primary analysis. These analyses resulted in annualized incremental rule costs of approximately $43.1 million and $33.0 million respectively, a 13 percent increase or decrease from the primary analysis results of $38.1 million at a 3 percent discount rate.

Additional uncertainties correspond more directly to specific assumptions made in constructing the cost model. If the assumptions for such items are incorrect, there may be significant cost implications outside of the general price level uncertainties discussed above. These cost items are described in Section 5.9.2 of the Cost Analysis.

EPA requested and received comments on the cost analysis presented in the preamble of the proposed rule. One commenter expressed concern that EPA overstated risks to USDWs, which may discourage investment in CCS. EPA notes that the risks have been discussed as low, based on the rule requirements and the redundancy in those requirements. One commenter requested that costs be estimated for a range of projects, rather than only the number of projects estimated in the cost analysis. EPA notes that the cost analysis for the final rule presents sensitivity analyses that consider 5 and 54 projects as the lower and upper bound number of projects deployed which is comparable with the Subpart RR analysis. The sensitivity analyses are intended to further explore the implications of alternative climate policy scenarios.

EPA received comments on the proposal cost analysis section that suggested that various estimated costs were too high, too low, or absent. EPA clarifies that cost estimates are presented in incremental terms. For this reason, costs may seem lower or less comprehensive than expected. However, EPA increased some costs, such as labor rates, in response to comments. Using industry survey data from the American Association of Petroleum Geologists and the Society for Petroleum Engineers, as presented in the Cost Analysis, EPA increased the estimated labor rates significantly from the Bureau of Labor Statistics estimates used in the analysis for the proposed rule. The updated rates (weighted by 1.6 for overhead) in the analysis for the final rule are $110.62 and $107.23 in 2008$ for engineers and geologists, respectively. These correspond approximately to annual salaries of $143,800 and $139,400 and represent an approximately 115 percent and a one percent increase, respectively, for engineers and geologists from the proposed rule analysis. For more details please see the Cost Analysis for the Final GS Rule (USEPA, 2010d).

Lastly, many commenters believed that an assumption of three monitoring wells per GS injection well was too high or too low a ratio, or should be modeled for a range of values. EPA changed the algorithm for calculating the number of monitoring wells to be based on the AoR, instead of the number of injection wells. For a representative saline project of approximately 23.3 square miles, EPA assumed 12 monitoring wells (six above the injection zone, and six into the injection zone), which EPA understands will be an overestimate in some cases and an underestimate in others. Because EPA recognizes the inherent uncertainty in this assumption, the cost analysis for the proposed rule presented and for the final rule presents a sensitivity analysis based on alternative estimates of 25 percent more and 25 percent fewer monitoring wells than the number assumed for the primary analysis.

c. Supplementary Cost and Uncertainties in Cost Estimates

To better establish the context in which to evaluate the cost analysis for this rule, EPA considers three types of costs that are not accounted for explicitly for this rule: (1) Costs that are incurred beyond the 50-year timeframe of the analysis, (2) costs that could arise due to a higher rate of deployment of CCS in the future in response to climate change legislation, and (3) overall costs of CCS and their relationship to the proportion of such costs attributable to the requirements. Because GS is in the early phase of development, and given the significant interest in research, development, and eventual commercialization of CCS, EPA provides a preliminary discussion of the potential significance of these costs below.

The cost analysis for this rule estimates costs that EPA anticipates will be incurred during a 50-year timeframe beginning with rule promulgation.[6] When analyzing costs for a commercial-size saline formation sequestration project that begins in year one of the cost analysis, EPA assumes that the first year is a pre-construction and construction period, followed by 40 years of injection and then either 10, 50, or 100 years of PISC as indicated in the cost analysis for the RAs considered. Given the 50-year timeframe (changed from 25 years in the proposed rule) of the analysis, the first nine years (changed from four years in proposed rule) of the PISC period would be captured in the cost analysis for a project beginning in year one, and fewer or no years of PISC for a project beginning later in the 50-year analytical timeframe would be included. EPA estimates that the incremental present value sequestration costs above the baseline costs incurred for one representative large deep saline project within the 50-year timeframe of the cost analysis are approximately $1.26/metric tonne CO_2. These costs over the full lifetime of the sequestration project are estimated to be $1.40/metric tonne CO_2. Thus the 50-year timeframe (changed from 25 years in proposed rule) captures approximately 90 percent (changed from 75 percent in the proposed rule) of the present value lifetime incremental costs associated with implementing this rule. EPA notes, however, that the longer time horizon over which costs are estimated inherently introduces increasing amounts of uncertainty into those estimates, and that the relatively low percentage share of these costs as a fraction of the total costs is significantly influenced by the long horizon (greater than 50 years) over which they are discounted.

The cost analysis assumes that Class VI well owners or operators will inject approximately 1.0 billion metric tons (or 1.0 Petagram, Pg) of CO_2 cumulatively over the next 50 years.[7] The start years of these projects, for both pilot and large-scale saline, are staggered over the first seven years of the period of analysis.[8] Based on the assumed deployment schedule, the analysis captures the full injection periods for approximately 10 large scale saline projects (with an injection period of 40 years) and 2 pilot saline projects (with an injection period of four years), and for 14 ER projects (with an assumed injection period of 10 years), which are

[6] A detailed discussion of the timeframe over which the costs of the final requirements were estimated can be found in the Cost Analysis. The 50 years of costs are calculated in terms of their present value (2008$) and then annualized over a 25-year period for a more consistent comparison to other regulations.

[7] A more detailed discussion of these projects can be found in the Cost Analysis.

[8] A detailed table of the scheduled deployment of projects assumed in the baseline over the 50-year timeframe can be found in Exhibit 3.1 of the Cost Analysis.

in oil and gas reservoirs. The analysis assumes that 10 percent of projects initiated will include waiver applications, and that 50 percent of those applications will be approved, while the other 50 percent of waiver applicants are removed from the baseline. The analysis also assumes that five percent of project permits for the initial baseline estimate of 29 projects will not be approved for geological or mechanical reasons.[9] While the baseline injection amount represents a significant step towards demonstrating the feasibility of CCS on an annual basis, it represents a small amount of current CO_2 emissions in the United States (approximately one percent).

The U.S. fleet of 1,493 coal-fired power generators emits 1.932 Pg CO_2 equivalent per year. The technical or economic viability of retrofitting these or other industrial facilities with CCS is not the subject of this rulemaking. However, if some percentage of these facilities undertook CCS and used GS, they (or the owner or operator of the Class VI injection wells) would be subject to the UIC requirements. For example, if 25 percent of these facilities undertook CCS (assuming a 90 percent capture rate and the incremental rule costs outlined in Table IV–4) the annualized incremental sequestration costs associated with meeting the Class VI requirements would be on the order of $546 million. Similarly, if 100 percent of these plants undertook CCS, the annualized incremental costs would be on the order of $2.2 billion, although it is unlikely that all coal plants would deploy CCS simultaneously. These preliminary cost estimates represent the annualized incremental cost of meeting the additional sequestration requirements in the rule, which would be incurred over the lifetime of the sequestration projects, assuming that all sequestration projects begin in the same year. These cost estimates were not generated from a full economic analysis or included in the cost analysis for this rule, due to the uncertainty of what percentage, if any, of such facilities will deploy CCS in the future. However, based on current research, the uncertainty in labor or service costs is not likely to contribute significantly as a rapid, wide-scale increase in deployment is not expected.[10] Therefore, the cost estimates presented represent a sensitivity analysis of the potential costs, assuming that 25 percent or 100 percent of all plants undertake CCS beginning in the same year, and do not take into consideration CCS deployment rates and project-specific costs. Actual annualized costs incurred as CCS deploys in the future could be higher or lower, depending on a number of factors, including deployment rates, capital and labor cost trends, and the shape of the learning curve among industry and State/Federal operators.

Based on current literature, sequestration costs are expected to be a small component of total CCS project costs. Table IV–4 shows example total annualized CCS project costs broken down by capture, transportation, and sequestration components. The largest component of total CCS project costs is the cost of capturing CO_2 ($42.90/metric tonne CO_2 for capture from an integrated gasification combined cycle power plant.[11]) Transportation costs vary widely depending on the distance from emission source to sequestration site, but EPA uses a long-term average estimate of $4.60/metric tonne CO_2.[12] EPA estimates total sequestration costs for a commercial-size deep saline project to be approximately $3.80/ metric tonne CO_2, of which approximately $1.40/metric tonne CO_2 is attributable to complying with requirements of this rule (including PISC). Based on the project costs outlined in Table IV–4, the requirements amount to approximately 2.7 percent of the total CCS project costs.

[7] A more detailed discussion of these projects can be found in the Cost Analysis.

[8] A detailed table of the scheduled deployment of projects assumed in the baseline over the 50-year timeframe can be found in Exhibit 3.1 of the Cost Analysis.

[9] Of the 29 projects that compose the initial baseline, a total of 10 percent, or approximately 3 projects, will not be approved based on their permit or waiver applications; costs for compiling the applications and reviewing them are included in the cost analysis, but no further costs are incurred for those projects that do not get approved. EPA recognizes that this may omit opportunity costs of projects that do not go forward.

[10] Potential increase in costs due to increased deployment rates and an associated rise in demand for labor or services in the field were considered in

Table IV-4. Example Total Annualized CCS Project Costs

Example Total CCS Project Costs (including capture at an IGCC plant, transportation, and deep saline reservoir at commercial scale sequestration)		
	Cost over lifetime of project ($/metric tonne)	Percentage of Total CCS Project Cost (%)
Capture (IGCC plant)	$ 42.90	83.6%
Transportation Estimate	$ 4.60	9.0%
Baseline Sequestration	$ 2.40	4.7%
Incremental Final Rule Sequestration Requirements	$ 1.40	2.7%
Total CCS Project Cost	**$ 51.30**	**100%**

Notes:

1) Detail may not add due to rounding.

2) Transportation cost estimates are based on a distance of 150 miles.

B. Comparison of Benefits and Costs of RAs Considered

1. Costs Relative to Benefits; Maximizing Net Social Benefits

EPA developed a relative risk analysis in place of a comparison of quantified benefits (a direct numerical comparison of costs to benefits) because GS is a new technology and data collection on the potential effects of GS on USDWs are ongoing. Costs can only be compared to qualitative relative risks as discussed in section IV.A.1.

Compared to the baseline, RA3 provides greater protection to USDWs because it is specifically tailored to GS injection activities. The current regulatory requirements do not specifically consider the injection of a buoyant, corrosive (in the presence of water) fluid. In particular, RA3 includes increased monitoring requirements that provide the amount of protection the Agency estimates is necessary for USDWs. As described in section IV.A. (National Benefits and Costs of the Rule), monitoring requirements account for 49 percent of the incremental regulatory costs, of which 74 percent is incurred for the construction, operation, and maintenance of monitoring wells, and the other 26 percent for tracking of the plume and pressure front through complex modeling at a minimum of every five years for all operators and for monitoring for CO_2 leakage. Public awareness of these protective measures would be expected to enhance public acceptance of GS.

EPA also compared RA1 and RA2 to the baseline (discussed in the proposed rule of July 2008). RA1 does not contain specific requirements but requires operators to meet a performance standard regarding protection of USDWs. RA2 is similar to the Class II UIC requirements, with some additional construction and PISC requirements. See the Cost Analysis (USEPA, 2010d) for a more detailed description. RA1 and RA2 do not provide the specific safeguards against CO_2 migration that RA3 does because of a significantly greater amount of discretion allowed to Directors and operators for interpreting requirements, and less stringent requirements for some compliance activities. Only RA3 and RA4 require the periodic complex modeling exercise for tracking the plume, for example. RA4 provides greater safeguards against CO_2 migration, but at a much higher cost.

2. Cost Effectiveness and Incremental Net Benefits

RA1 and RA2 provide lower costs than RA3 but at increased levels of risk to USDWs. Although RA4 has more stringent requirements, EPA does not believe that the increased requirements and the increased costs are necessary to provide protection to USDWs. Therefore EPA believes that RA3 is the most appropriate alternative.

C. Conclusions

RA3 provides a high level of protection to USDWs overlying and underlying GS CO_2 injection zones. It does so at lower costs than the more stringent RA4 while providing significantly more protection than RA1 or RA2. Therefore EPA has selected RA3 for the final GS Rule.

V. Statutory and Executive Order Review

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is a "significant regulatory action." Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act (PRA)

The information collection requirements in this rule will be submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them.

The information collected as a result of this rule will allow EPA and State permitting authorities to review geologic information about a proposed injection project to evaluate its suitability for safe and effective GS. It also allows the Agency to fulfill the requirements of the UIC program to verify throughout the life of the injection project that protective requirements are in place and that USDWs are protected. The collection requirements are mandatory under the SDWA (42 U.S.C. 300h *et seq.*).

For the first three years after publication of the final rule in the **Federal Register**, the major information requirements apply to a total of 38 respondents, for an average of 12.6 respondents per year. The total incremental burden (for owners or operators, permitting authorities, and the Agency) associated with the change in moving from the information requirements of the UIC program for Class I non-hazardous wells (baseline) to the selected alternative under the GS Rule over the three years covered by the Information Collection Request (ICR) for the Geologic Sequestration Rule is 53,740 hours, for an average of 17,913 hours per year. The total incremental reporting and recordkeeping cost over the three year clearance period is $36.9 million, for an average of $12.3 million per year (simple average over three years). The average burden per response (*i.e.,* the amount of time needed for each activity that requires a collection of information) is 423 hours; the average cost per response is $290,695. The collection requirements are mandatory under SDWA (42 U.S.C. 3501 *et seq.*). Details on the calculation of the rule information collection burden and costs can be found in the ICR (USEPA, 2010e) and Chapter 5 of the Cost Analysis (USEPA, 2010d). A summary of the burden and costs of the collection is presented in Exhibit V–1.

Exhibit V-1 Average Annual Net Change Burden and Costs for the GS ICR

Respondent Type	Annual Respondents	Annual Burden Hours	Cost				Annual Responses
			Annual Labor Cost	Annual Capital Cost	Annual O&M Cost	Total Annual Cost	
Owners or Operators	1.0	1,549	$ 204,574	$ 5,827,027	$ 5,454,346	$ 11,485,946	6.9
Permitting Authorities	10.7	11,241	$ 555,763	$ -	$ -	$ 555,763	23.6
Agency	1.0	5,123	$ 256,880	$ -	$ -	$ 256,880	11.7
Total	12.6	17,913	$ 1,017,217	$ 5,827,027	$ 5,454,346	$ 12,298,589	42.3

Source:

Information Collection Request for the Geologic Sequestration Rule (USEPA, 2010c).

Notes:

1) Detail may not add exactly to total due to independent rounding.

2) "Annual Burden Hours" reflects an annual average for all project types over the 3-year ICR period.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. In addition, EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information requirements contained in this final rule.

C. Regulatory Flexibility Act (RFA)

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedures Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business primarily engaged in the generation, transmission, and/or distribution of electric energy for sale as defined by North American Industry Classification System (NAICS) codes 221111, 221112, 221113, 221119, 221121, 221122 with total electric output for the preceding fiscal year that did not exceed 4 million megawatt hours; (2) a small business primarily engaged in petroleum production as defined by NAICS code 324110 with fewer than 1,500 employees and less than 125,000 barrels per calendar day in total Operable Atmospheric Crude Oil Distillation capacity, as specified for government procurement purposes (capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput); (3) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (4) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. The small entity definitions for commercial operations focus on the electricity and oil and gas sectors because these are the sectors most likely to deploy GS.

After considering the economic impacts of today's final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This rule does not impose any requirements on small entities.

Furthermore, GS is a technologically complex activity, the cost of which is anticipated to be prohibitive to small entities. Therefore it is anticipated small entities would not elect to sequester CO_2 via injection wells, and thus the rule will not have any impact on them.

D. Unfunded Mandates Reform Act (UMRA)

This rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. The total annual incremental costs estimated for the implementation of this rule are well under $100 million, resulting in expenditures for the entity groupings required under an UMRA analysis that also fall far below the $100 million per year threshold. Thus, this rule is not subject to the requirements of sections 202 or 205 of UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. Government responsibilities for oversight and implementation of this rule reside with State or Federal agencies and not with small governments.

E. Executive Order 13132: Federalism

Under section 6(b) of Executive Order 13132, EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and Local governments, or EPA consults with State and Local officials early in the process of developing the proposed action. In addition, under section 6(c) of Executive Order 13132, EPA may not issue an action that has federalism implications and that preempts State law, unless the Agency consults with State and Local officials early in the process of developing the proposed action.

EPA concluded that today's action does not have federalism implications. This rule will not impose substantial direct compliance costs on State or Local governments, nor does EPA anticipate that it will preempt State law. Thus, the requirements of sections 6(b) and 6(c) of the Executive Order do not apply to this action.

Consistent with EPA policy, EPA nonetheless consulted with representatives of State and local governments early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. Representatives included the National Governors' Association, the National Conference of State Legislatures, the Council of State Governments, the National League of Cities, the U.S. Conference of Mayors, the National Association of Counties, the International City/County Management Association, the National Association of Towns and Townships, and the County Executives of America. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on the proposed action from State and local officials. See section II of the Preamble for more details on consultation with State and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) EPA may not issue a regulation that has Tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by Tribal governments, or EPA consults with Tribal officials early in the process of developing the proposed regulation and develops a Tribal summary impact statement.

EPA has concluded that this action may have Tribal implications. However, it will neither impose substantial direct compliance costs on Tribal governments, nor preempt Tribal law. Indian Tribes may voluntarily apply for primary enforcement responsibility to regulate the UIC program in lands under their jurisdiction (See section II.G for more details on primacy). Currently, two Tribes have received primacy for the UIC program under section 1425 of the SDWA since the publication of the proposed rule. EPA is responsible for implementing the UIC program in the event that States or Tribes do not seek primary enforcement responsibility. EPA clarifies that regardless of whether Tribes have UIC program primacy, the rule protects USDWs from contamination and therefore protects all populations from adverse health effects related to potential USDW contamination.

EPA consulted with Tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. A summary of the Tribal consultation calls are included in the docket for the GS rulemaking. See section II.E.3 for more information on the details of the Tribal consultation process.

As required by section 7(a), EPA's Tribal Consultation Official has certified that the requirements of the Executive Order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to EO 13045 (62 FR 19885, April 23, 1997) because it is not economically significant as defined by EO 12866 and because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. Today's rule does not require or provide incentive for firms to engage in GS, however, it does protect USDWs from potential negative impacts from GS of CO_2 should a firm decide to undertake such a project. Health and risk assessments related to GS of CO_2 and its effects on humans and the environment are presented in the *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide* (USEPA, 2008b). Additionally, EPA notes that it is funding and monitoring research related to the potential for USDW contamination associated with GS projects. Much of this research focuses on potential exceedances of drinking water standards (as suggested), which were developed by EPA and take into account impacts on children. Please see section II of this Preamble for more details on this research.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The higher degree of regulatory certainty and clarity in the permitting process may, in fact, have a positive effect on the energy sector. Specifically, if climate change legislation that imposes caps or taxes on CO_2 emissions is passed in the future, energy generation firms and other CO_2 producing industries will have an economic incentive to reduce emissions, and this rule will provide regulatory certainty in determining how best to meet any new requirements (for example, by maintaining or increasing production while staying within the emissions cap or avoiding some carbon taxes). The rule may allow some firms to extend the life of their existing capital investment in plant machinery or plant processes.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves environmental monitoring or measurement. Consistent with the Agency's Performance Based Measurement System (PBMS), EPA has decided not to require the use of specific, prescribed analytic methods. Rather, the rule will allow the use of any method that meets the performance criteria. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. While EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified, the PBMS approach is fully consistent with the use of voluntary consensus standards, as such standards are generally designed to address the same types of criteria required by PBMS.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations. Existing electric power generation plants that burn fossil fuels may be more prevalent in areas with higher percentages of people who are minorities or have lower incomes on average, but it is hard to predict where new plants with CCS will be built. EPA is developing guidance for UIC Directors that places emphasis on considering the potential impact of any Class VI permits on communities (such as minority and low income populations) when evaluating Class VI injection well permit applications, as well as provides suggestions and tools for targeted outreach to ensure more meaningful public input and participation from the most affected communities during the permit evaluation and approval process.

This rule does not require that GS be undertaken; but does require that if it is undertaken, operators will conduct the activity in such a way as to protect USDWs from endangerment caused by CO_2. Additionally, this rule will ensure that all areas of the United States are subject to the same minimum Federal requirements for protection of USDWs from endangerment from GS. Additional detail regarding the potential risk of the rule is presented in the *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide* (USEPA, 2008b).

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective January 10, 2011.

VI. References

Benson. 2008. Multi-Phase Flow and Trapping of CO_2 in Saline Aquifers. Sally M. Benson, SPE, Stanford University. Copyright 2008, Offshore Technology Conference.

Birkholzer, J., T. Apps, L. Zheng, Y. Zhang, T. Xu, and C.F. Tsang. 2008a. Research Project on CO_2 Geological Storage and Groundwater Resources: Water Quality Effects Caused by CO_2 Intrusion into Shallow Groundwater. LBNL paper #LBNL–1251E. *http://repositories.cdlib.org/lbnl/LBNL–1251E.*

Birkholzer, J., Zhou, Q., Zhang, K., Jordan, P., Rutqvist, J., and C.F. Tsang. 2008b. Research Project on CO_2 Geological Storage and Groundwater Resources: Large-Scale Hydrological Evaluation and Modeling of the Impact on Groundwater Systems. NETL Project Annual Report, October 1, 2007 to September 30, 2008.

BLM. 2009. Framework for Geological Carbon Sequestration on Public Land.

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.

DOE NETL. 2007. Carbon Sequestration Atlas of the U.S. and Canada. U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory. March 2007.

DOE NETL. 2008. Carbon Sequestration Atlas of the United States and Canada (Atlas II). Second Edition. National Energy Technology Laboratory, Pittsburgh, PA, USA.

Dooley, J.J., R.T. Dahowski, C.L. Davidson. 2008. On the Long-Term Average Cost of CO_2 Transport and Storage, Pacific Northwest National Laboratory, PNNL–17389.

Dooley, J., C. Davidson, and R. Dahowski. 2009. An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. Joint Global Change Research Institute. Pacific Northwest National Laboratory. PNNL–18520.

Duncan, I.J., J.P. Nicot, and J.W. Choi. 2009. Risk Assessment for Future CO_2 Sequestration Projects Based on CO_2 Enhanced Oil Recovery in the U.S. Energy Procedia 1(1): 2037–2042.

Energy Information Administration (EIA). 2009. Annual Energy Review, 2008.

EPRI. 1999. Enhanced Oil Recovery Scoping Study. Report TR–113836.

GAO. 2008. Climate Change—Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage as a Key Mitigation Option. GAO–08–1080.

GAO. 2010. Climate Change: A Coordinated Strategy Could Focus Federal Geoengineering Research and Inform Governance Efforts. GAO–10–903.

Holloway, S., J. Pearce, V. Hards, T. Ohsumi, and J. Gale. 2007. Natural Emissions of CO_2 from the Geosphere and their Bearing on the Geological Storage of Carbon Dioxide. Energy 32: 1194–1201.

IEA. 2003. Acid Gas Injection: A Study of Existing Operations. Phase 1: Final Report.

IEA. 2008. CO_2 Capture and Storage: A Key Abatement Option. Energy Technology Analysis. Paris: IEA/OECD, 2008.

IPCC. 2005. IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Metz, B., O. Davidson, H.C. de Coninck, M. Loos, and L.A. Meyer (eds.). New York: Cambridge University Press.

IRS. 2009. Internal Revenue Service (IRS) Guidance for Tax Incentives for GS Projects 2009–44 IRB *http://www.irs.gov/irb/2009–44_IRB/ar11.html#d0e1860.*

Julian, J.Y., G.E. King, J.E. Johns, J.K. Sack, and D.B. Robertson. 2007. Detecting Ultra-Small Leaks with Ultrasonic Leak Detection-Case Histories from the North Slope, Alaska. Presented at International Oil Conference and Exhibition, 27–30 June, Veracruz, Mexico. Society of Petroleum Engineers. Paper Number 108906–MS.

Klusman, R.W. 2003. Evaluation of Leakage Potential from a Carbon Dioxide EOR/Sequestration Project. Energy Conversion and Management 44: 1921–1940.

Oldenburg, C.M., K. Pruess, and S.M. Benson. 2001. Process Modeling of CO_2 Injection into Natural Gas Reservoirs for Carbon Sequestration and Enhanced Gas Recovery. Energy and Fuels 15: 293–298.

Oil and Gas Journal. 2008. Enhanced Oil Recovery Survey. April 21, 2008, p. 41–59.

Schnaar, G., and D.C. Digiulio. 2009. Computational Modeling of the Geologic Sequestration of Carbon Dioxide. Vadose Zone J. 8: 389–403.

Skinner, L. 2003. CO_2 Blowouts: An Emerging Problem. World Oil. 224(1).

Somaschini, G., J. Lovell, H. Abdullah, B. Chariyev, P. Singh, and F. Arachman. 2009. Subsea Deployment of Instrumented Sand Screens in High-Rate Gas Wells. Presented at SPE Annual Technical Conference and Exhibition, 4–7 October 2009, New Orleans,

Louisiana. Society of Petroleum Engineers. Paper Number 125047–MS.
USEPA. 2001. Class I Underground Injection Control Program: Study of the Risks Associated with Class I Underground Injection Wells.
USEPA. 2007. Using the Class V Experimental Technology Well Classification for Pilot Carbon Geologic Sequestration Projects—Underground Injection Control Program Guidance (UICPG # 83). March 2007.
USEPA. 2008a. Climate Change—Climate Economics. Economic Analyses. Updated May 7, 2008. *http://www.epa.gov/climatechange/economics/economicanalyses.html.*
USEPA. 2008b. Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide.
USEPA. 2010. Climate Change Science Facts. 430–10–F–002.
USEPA. 2010a. International Geologic Sequestration Efforts: An Overview of the Sleipner, Weyburn, and In Salah Projects and Summary of International Regulatory Developments. 816–R10–011.
USEPA. 2010b. Drinking Water Treatment Considerations: Water Quality, Carbon Dioxide Concentration, and Geologic Sequestration Projects. 816–R10–014.
USEPA. 2010c. Technologies Available to Address Induced Faults and Fractures: Considerations for GS Sites. 816–R10–0018.
USEPA. 2010d. Cost Analysis for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells (Final GS Rule). 816–R10–013.
USEPA. 2010e. Information Collection Request for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration. 816–R10–012.
USEPA. 2010f. EPA's June 2010 American Power Act Analysis. *http://www.epa.gov/climatechange/economics/economicanalyses.html#apa2010.*
USGS. 2010. A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage. *http://pubs.usgs.gov/of/2010/1127/.*
WRI. 2007. J. Logan, J. Venezia, and K. Larsen. Issue Brief: Opportunities and Challenges for Carbon Capture and Sequestration. WRI Issue Brief, No. 1. World Resources Institute. October 2007. Washington, DC.

List of Subjects

40 CFR Part 124

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous waste, Indians—lands, Reporting and recordkeeping requirements, Water pollution control, Water supply.

40 CFR Part 144

Environmental protection, Administrative practice and procedure, Confidential business information, Hazardous waste, Indians—lands, Reporting and recordkeeping requirements, Surety bonds, Water supply.

40 CFR Part 145

Environmental protection, Confidential business information, Indian—lands, Intergovernmental relations, Penalties, Reporting and recordkeeping requirements, Water supply.

40 CFR Part 146

Environmental protection, Hazardous waste, Indian—lands, Reporting and recordkeeping requirements, Water supply.

40 CFR Part 147

Environmental protection, Indian—lands, Intergovernmental relations, Penalties, Reporting and recordkeeping requirements, Water supply.

Dated: November 22, 2010.

Lisa P. Jackson,

Administrator.

■ For the reasons set forth in the preamble, title 40 chapter I of the Code of Federal Regulations is amended as follows:

PART 124—PROCEDURES FOR DECISION MAKING

■ 1. The authority citation for part 124 continues to read as follows:

Authority: Resource Conservation and Recovery Act, 42 U.S.C. 6901 *et seq.;* Safe Drinking Water Act, 42 U.S.C. 300f *et seq.;* Clean Water Act, 33 U.S.C. 1251 *et seq.;* Clean Air Act, 42 U.S.C. 7401 *et seq.*

Subpart A—General Program Requirements

■ 2. Section 124.10 is amended by revising paragraph (c) introductory text and by adding paragraph (c)(1)(xi) to read as follows:

§ 124.10 Public notice of permit actions and public comment period.

* * * * *

(c) Methods (applicable to State programs, see 40 CFR 123.25 (NPDES), 145.11 (UIC), 233.23 (404), and 271.14 (RCRA)). Public notice of activities described in paragraph (a)(1) of this section shall be given by the following methods:

(1) * * *

(xi) For Class VI injection well UIC permits, mailing or e-mailing a notice to State and local oil and gas regulatory agencies and State agencies regulating mineral exploration and recovery, the Director of the Public Water Supply Supervision program in the State, and all agencies that oversee injection wells in the State.

* * * * *

PART 144—UNDERGROUND INJECTION CONTROL PROGRAM

■ 3. The authority citation for part 144 continues to read as follows:

Authority: Safe Drinking Water Act, 42 U.S.C. 300f *et seq.;* Resource Conservation and Recovery Act, 42 U.S.C. 6901 *et seq.*

Subpart A—General Provisions

■ 4. Section 144.1 is amended by adding paragraph (f)(1)(viii) and by revising paragraph (g) introductory text to read as follows:

§ 144.1 Purpose and scope of part 144.

* * * * *

(f) * * *

(1) * * *

(viii) Subpart H of part 146 sets forth requirements for owners or operators of Class VI injection wells.

* * * * *

(g) *Scope of the permit or rule requirement.* The UIC permit program regulates underground injection by six classes of wells (see definition of "well injection," § 144.3). The six classes of wells are set forth in § 144.6. All owners or operators of these injection wells must be authorized either by permit or rule by the Director. In carrying out the mandate of the SDWA, this subpart provides that no injection shall be authorized by permit or rule if it results in the movement of fluid containing any contaminant into underground sources of drinking water (USDWs—see § 144.3 for definition), if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR part 141 or may adversely affect the health of persons (§ 144.12). Existing Class IV wells which inject hazardous waste directly into an underground source of drinking water are to be eliminated over a period of six months and new such Class IV wells are to be prohibited (§ 144.13). For Class V wells, if remedial action appears necessary, a permit may be required (§ 144.25) or the Director must require remedial action or closure by order (§ 144.6(c)). During UIC program development, the Director may identify aquifers and portions of aquifers which are actual or potential sources of drinking water. This will provide an aid to the Director in carrying out his or her duty to protect all USDWs. An aquifer is a USDW if it fits the definition under § 144.3, even if it has not been "identified." The Director may also designate "exempted aquifers" using the criteria in 40 CFR 146.4 of this chapter. Such aquifers are those which would otherwise qualify as "underground sources of drinking water" to be protected, but which have no real potential to be used as drinking water sources. Therefore, they are not USDWs. No aquifer is an exempted aquifer until it has been affirmatively designated under the procedures at § 144.7. Aquifers which do not fit the definition of "underground source of drinking water" are not "exempted aquifers." They are simply not subject to the special protection afforded USDWs. During initial Class VI program development, the Director shall not expand the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption for Class VI injection wells and EPA shall not approve a program that applies for aquifer exemption expansions of Class II–Class VI exemptions as part of the program description. All Class II to Class VI aquifer exemption expansions previously issued by EPA must be incorporated into the Class VI program descriptions pursuant to requirements at § 145.23(f)(9).

* * * * *

■ 5. Section 144.3 is amended by adding in alphabetic order the definition "geologic sequestration" to read as follows:

§ 144.3 Definitions.

* * * * *

Geologic sequestration 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.

* * * * *

■ 6. Section 144.6 is amended by revising paragraph (e) and adding paragraph (f) to read as follows:

§ 144.6 Classification of wells.

* * * * *

(e) *Class V.* Injection wells not included in Class I, II, III, IV, or VI. Specific types of Class V injection wells are described in § 144.81.

(f) *Class VI.* 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 § 146.95 of this chapter; 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 §§ 146.4 of this chapter and 144.7(d).

■ 7. Section 144.7 is amended as follows:

■ a. Revising paragraph (a);

■ b. Revising paragraphs (b)(1) and (b)(2); and

■ c. Adding paragraph (d) as follows:

§ 144.7 Identification of underground sources of drinking water and exempted aquifers.

(a) The Director may identify (by narrative description, illustrations, maps, or other means) and shall protect as underground sources of drinking water, all aquifers and parts of aquifers which meet the definition of "underground source of drinking water" in § 144.3, except to the extent there is an applicable aquifer exemption under paragraph (b) of this section or an expansion to the areal extent of an existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption for the exclusive purpose of Class VI injection for geologic sequestration under paragraph (d) of this section. Other than EPA approved aquifer exemption expansions that meet the criteria set forth in § 146.4(d) of this chapter, new aquifer exemptions shall not be issued for Class VI injection wells. Even if an aquifer has not been specifically identified by the Director, it is an underground source of drinking water if it meets the definition in § 144.3.

(b)(1) The Director may identify (by narrative description, illustrations, maps, or other means) and describe in geographic and/or geometric terms (such as vertical and lateral limits and gradient) which are clear and definite, all aquifers or parts thereof which the Director proposes to designate as exempted aquifers using the criteria in § 146.4 of this chapter.

(2) No designation of an exempted aquifer submitted as part of a UIC program shall be final until approved by the Administrator as part of a UIC program. No designation of an expansion to the areal extent of a Class II enhanced oil recovery or enhanced gas recovery aquifer exemption for the exclusive purpose of Class VI injection for geologic sequestration shall be final until approved by the Administrator as a revision to the applicable Federal UIC program under part 147 or as a substantial revision of an approved State UIC program in accordance with § 145.32 of this chapter.

* * * * *

(d) *Expansion to the Areal Extent of Existing Class II Aquifer Exemptions for Class VI Wells.* Owners or operators of Class II enhanced oil recovery or enhanced gas recovery wells may request that the Director approve an expansion to the areal extent of an aquifer exemption already in place for a Class II enhanced oil recovery or enhanced gas recovery well for the exclusive purpose of Class VI injection for geologic sequestration. Such requests must be treated as a revision to the applicable Federal UIC program under part 147 or as a substantial program revision to an approved State UIC program under § 145.32 of this chapter and will not be final until approved by EPA.

(1) The owner or operator of a Class II enhanced oil recovery or enhanced gas recovery well that requests an expansion of the areal extent of an existing aquifer exemption for the exclusive purpose of Class VI injection for geologic sequestration must define (by narrative description, illustrations, maps, or other means) and describe in geographic and/or geometric terms (such as vertical and lateral limits and gradient) that are clear and definite, all aquifers or parts thereof that are requested to be designated as exempted using the criteria in § 146.4 of this chapter.

(2) In evaluating a request to expand the areal extent of an aquifer exemption of a Class II enhanced oil recovery or enhanced gas recovery well for the purpose of Class VI injection, the Director must determine that the request meets the criteria for exemptions in § 146.4. In making the determination, the Director shall consider:

(i) Current and potential future use of the USDWs to be exempted as drinking water resources;

(ii) 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 GS project, as informed by computational modeling performed pursuant to § 146.84(c)(1), in order to ensure that the proposed injection operation will not at any time endanger USDWs including non-exempted portions of the injection formation;

(iii) Whether the areal extent of the expanded aquifer exemption is of sufficient size to account for any possible revisions to the computational model during reevaluation of the area of review, pursuant to § 146.84(e); and

(iv) Any information submitted to support a waiver request made by the owner or operator under § 146.95, if appropriate.

■ 8. Section 144.8 is amended by adding paragraph (b)(2)(iii) to read as follows:

§ 144.8 Noncompliance and program reporting by the Director.

* * * * *

(b) * * *

(2) * * *

(iii) All Class VI program reports shall be consistent with reporting requirements set forth in § 146.91 of this chapter.

* * * * *

Subpart B—General Program Requirements

■ 9. Section 144.12 is amended by revising the first sentence in paragraph (b) to read as follows:

§ 144.12 Prohibition of movement of fluid into underground sources of drinking water.

* * * * *

(b) For Class I, II, III, and VI wells, if any water quality monitoring of an underground source of drinking water indicates the movement of any contaminant into the underground source of drinking water, except as authorized under part 146, the Director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting (including closure of the injection well) as are necessary to prevent such movement. * * *

* * * * *

■ 10. Section 144.15 is added to read as follows:

§ 144.15 Prohibition of non-experimental Class V wells for geologic sequestration.

The construction, operation or maintenance of any non-experimental Class V geologic sequestration well is prohibited.

■ 11. Section 144.18 is added to subpart B to read as follows:

§ 144.18 Requirements for Class VI wells.

Owners or operators of Class VI wells must obtain a permit. Class VI wells cannot be authorized by rule to inject carbon dioxide.

■ 12. Section 144.19 is added to subpart B to read as follows:

§ 144.19 Transitioning from Class II to Class VI.

(a) 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 geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations. In determining if there is an increased risk to USDWs, the owner or operator must consider the factors specified in § 144.19(b).

(b) The Director shall determine when there is an increased risk to USDWs compared to Class II operations and a Class VI permit is required. In order to make this determination the Director must consider the following:

(1) Increase in reservoir pressure within the injection zone(s);

(2) Increase in carbon dioxide injection rates;

(3) Decrease in reservoir production rates;

(4) Distance between the injection zone(s) and USDWs;

(5) Suitability of the Class II area of review delineation;

(6) Quality of abandoned well plugs within the area of review;

(7) The owner's or operator's plan for recovery of carbon dioxide at the cessation of injection;

(8) The source and properties of injected carbon dioxide; and

(9) Any additional site-specific factors as determined by the Director.

Subpart C—Authorization of Underground Injection by Rule

■ 13. Section 144.22 is amended by revising paragraph (b) to read as follows:

§ 144.22 Existing Class II enhanced recovery and hydrocarbon storage wells.

* * * * *

(b) *Duration of well authorization by rule.* Well authorization under this section expires upon the effective date of a permit issued pursuant to §§ 144.19, 144.25, 144.31, 144.33 or 144.34; after plugging and abandonment in accordance with an approved plugging and abandonment plan pursuant to §§ 144.28(c) and 146.10 of this chapter; and upon submission of a plugging and abandonment report pursuant to § 144.28(k); or upon conversion in compliance with § 144.28(j).

Subpart D—Authorization by Permit

■ 14. Section 144.31 is amended by revising paragraph (e) introductory text to read as follows:

§ 144.31 Application for a permit; authorization by permit.

* * * * *

(e) *Information requirements.* All applicants for Class I, II, III, and V permits shall provide the following information to the Director, using the application form provided by the Director. Applicants for Class VI permits shall follow the criteria provided in § 146.82 of this chapter.

* * * * *

■ 15. Section 144.33 is amended by revising paragraph (a)(4) and adding paragraph (a)(5).

§ 144.33 Area permits.

(a) * * *

(4) Used to inject other than hazardous waste; and

(5) Other than Class VI wells.

* * * * *

■ 16. Section 144.36 is amended by revising paragraph (a) to read as follows:

§ 144.36 Duration of permits.

(a) Permits for Class I and V wells shall be effective for a fixed term not to exceed 10 years. UIC permits for Class II and III wells shall be issued for a period up to the operating life of the facility. UIC permits for Class VI wells shall be issued for the operating life of the facility and the post-injection site care period. The Director shall review each issued Class II, III, and VI well UIC permit at least once every 5 years to determine whether it should be modified, revoked and reissued, terminated or a minor modification made as provided in §§ 144.39, 144.40, or 144.41.

* * * * *

■ 17. Section 144.38 is amended by revising paragraph (b) introductory text to read as follows:

§ 144.38 Transfer of permits.

* * * * *

(b) *Automatic transfers.* As an alternative to transfers under paragraph (a) of this section, any UIC permit for a well not injecting hazardous waste or injecting carbon dioxide for geologic sequestration may be automatically transferred to a new permittee if:

* * * * *

■ 18. Section 144.39 is amended as follows:

■ a. Revising the second sentence in paragraph (a) introductory text;

■ b. Revising the second sentence in paragraph (a)(3) introductory text; and

■ c. Adding a new paragraph (a)(5) to read as follows:

§ 144.39 Modification or revocation and reissuance of permits.

* * * * *

(a) * * * For Class I hazardous waste injection wells, Class II, Class III or Class VI wells the following may be causes for revocation and reissuance as well as modification; and for all other wells the following may be cause for revocation or reissuance as well as modification when the permittee requests or agrees.

* * * * *

(3) * * * Permits other than for Class I hazardous waste injection wells, Class II, Class III or Class VI wells may be

modified during their permit terms for this cause only as follows:

* * * * *

(5) *Basis for modification of Class VI permits.* Additionally, for Class VI wells, whenever the Director determines that permit changes are necessary based on:

(i) Area of review reevaluations under § 146.84(e)(1) of this chapter;

(ii) Any amendments to the testing and monitoring plan under § 146.90(j) of this chapter;

(iii) Any amendments to the injection well plugging plan under § 146.92(c) of this chapter;

(iv) Any amendments to the post-injection site care and site closure plan under § 146.93(a)(3) of this chapter;

(v) Any amendments to the emergency and remedial response plan under § 146.94(d) of this chapter; or

(vi) A review of monitoring and/or testing results conducted in accordance with permit requirements.

* * * * *

■ 19. Section 144.41 is amended by adding a new paragraph (h) to read as follows:

§ 144.41 Minor modifications of permits.

* * * * *

(h) Amend a Class VI injection well testing and monitoring plan, plugging plan, post-injection site care and site closure plan, or emergency and remedial response plan where the modifications merely clarify or correct the plan, as determined by the Director.

Subpart E—Permit Conditions

■ 20. Section 144.51 is amended to read as follows:

■ a. Adding a new paragraph (j)(4);

■ b. Revising paragraph (o); and

■ c. Removing the first sentence in paragraph (q)(1) and adding two sentences in its place; and

■ d. Revising the first sentence in paragraph (q)(2).

§ 144.51 Conditions applicable to all permits.

* * * * *

(j) * * *

(4) Owners or operators of Class VI wells shall retain records as specified in subpart H of part 146, including §§ 146.84(g), 146.91(f), 146.92(d), 146.93(f), and 146.93(h) of this chapter.

* * * * *

(o) A Class I, II or III permit shall include and a Class V permit may include conditions which meet the applicable requirements of § 146.10 of this chapter to ensure that plugging and abandonment of the well will not allow the movement of fluids into or between USDWs. Where the plan meets the requirements of § 146.10 of this chapter, the Director shall incorporate the plan into the permit as a permit condition. Where the Director's review of an application indicates that the permittee's plan is inadequate, the Director may require the applicant to revise the plan, prescribe conditions meeting the requirements of this paragraph, or deny the permit. A Class VI permit shall include conditions which meet the requirements set forth in § 146.92 of this chapter. Where the plan meets the requirements of § 146.92 of this chapter, the Director shall incorporate it into the permit as a permit condition. For purposes of this paragraph, temporary or intermittent cessation of injection operations is not abandonment.

* * * * *

(q) * * *

(1) The owner or operator of a Class I, II, III or VI well permitted under this part shall establish mechanical integrity prior to commencing injection or on a schedule determined by the Director. Thereafter the owner or operator of Class I, II, and III wells must maintain mechanical integrity as defined in § 146.8 of this chapter and the owner or operator of Class VI wells must maintain mechanical integrity as defined in § 146.89 of this chapter. * * *

(2) When the Director determines that a Class I, II, III or VI well lacks mechanical integrity pursuant to §§ 146.8 or 146.89 of this chapter for Class VI of this chapter, he/she shall give written notice of his/her determination to the owner or operator. * * *

* * * * *

■ 21. Section 144.52 is amended as follows:

■ a. By revising paragraph (a) introductory text;

■ b. Revising paragraph (a)(2);

■ c. Revising paragraphs (a)(7)(i)(A) and (a)(7)(ii); and

■ d. Revising paragraph (a)(8).

§ 144.52 Establishing permit conditions.

(a) In addition to conditions required in § 144.51, the Director shall establish conditions, as required on a case-by-case basis under § 144.36 (duration of permits), § 144.53(a) (schedules of compliance), § 144.54 (monitoring), and for EPA permits only § 144.53(b) (alternate schedules of compliance), and § 144.4 (considerations under Federal law). Permits for owners or operators of hazardous waste injection wells shall include conditions meeting the requirements of § 144.14 (requirements for wells injecting hazardous waste), paragraphs (a)(7) and (a)(9) of this section, and subpart G of part 146. Permits for owners or operators of Class VI injection wells shall include conditions meeting the requirements of subpart H of part 146. Permits for other wells shall contain the following requirements, when applicable.

* * * * *

(2) Corrective action as set forth in §§ 144.55, 146.7, and 146.84 of this chapter.

* * * * *

(7) * * *

(i) * * *

(A) The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to §§ 144.51(o), 146.10, and 146.92 of this chapter, and submitted a plugging and abandonment report pursuant to § 144.51(p); or

* * * * *

(ii) The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance, such as a financial statement or other materials acceptable to the Director. For EPA administered programs, the Regional Administrator may on a periodic basis require the holder of a lifetime permit to submit an estimate of the resources needed to plug and abandon the well revised to reflect inflation of such costs, and a revised demonstration of financial responsibility, if necessary. The owner or operator of a well injecting hazardous waste must comply with the financial responsibility requirements of subpart F of this part. For Class VI wells, the permittee shall show evidence of such financial responsibility to the Director by the submission of a qualifying instrument (see § 146.85(a) of this chapter), such as a financial statement or other materials acceptable to the Director. The owner or operator of a Class VI well must comply with the financial responsibility requirements set forth in § 146.85 of this chapter.

(8) *Mechanical integrity.* A permit for any Class I, II, III or VI well or injection project which lacks mechanical integrity shall include, and for any Class V well may include, a condition prohibiting injection operations until the permittee shows to the satisfaction of the Director under § 146.8, or § 146.89 of this chapter for Class VI, that the well has mechanical integrity.

* * * * *

Subpart G—Requirements for Owners and Operators of Class V Injection Wells

■ 22. Section 144.80 is amended by revising the first sentence in paragraph (e) and by adding paragraph (f) to read as follows:

§ 144.80 What is a Class V injection well?

* * * * *

(e) *Class V.* Injection wells not included in Class I, II, III, IV or VI. * * *

(f) *Class VI.* Wells used for geologic sequestration of carbon dioxide beneath the lowermost formation containing a USDW, except those wells that are experimental in nature; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at § 146.95 of this chapter; or, wells used for geologic sequestration of carbon dioxide that have received an expansion to the areal extent of a existing Class II enhanced oil recovery or enhanced gas recovery aquifer exemption pursuant to § 146.4 of this chapter and § 144.7(d).

PART 145—STATE UIC PROGRAM REQUIREMENTS

■ 23. The authority citation for part 145 continues to read as follows:

Authority: 42 U.S.C. 300f *et seq.*

Subpart A—General Program Requirements

■ 24. Section 145.1 is amended by adding paragraph (i) to read as follows:

§ 145.1 Purpose and scope.

* * * * *

(i) States seeking primary enforcement responsibility for Class VI wells must submit a primacy application in accordance with subpart C of this part and meet all requirements of this part. States may apply for primary enforcement responsibility for Class VI wells independently of other injection well classes.

Subpart C—State Program Submissions

■ 25. Section 145.21 is amended by adding paragraph (h) to read as follows:

§ 145.21 General requirements for program approvals.

* * * * *

(h) To establish a Federal UIC Class VI program in States not seeking full UIC primary enforcement responsibility approval, pursuant to the SDWA section 1422(c), States shall, by September 6, 2011, submit to the Administrator a new or revised State UIC program complying with §§ 145.22 or 145.32 of this part. Beginning on September 6, 2011 the requirements of subpart H of part 146 of this chapter will be applicable and enforceable by EPA in each State that has not received approval of a new Class VI program application under section 1422 of the Safe Drinking Water Act or a revision of its UIC program under section 1422 of the Safe Drinking Water Act to incorporate subpart H of part 146. Following September 6, 2011, EPA will publish a list of the States where subpart H of part 146 has become applicable.

■ 26. Section 145.22 is amended by revising paragraphs (a) introductory text and (a)(5) to read as follows:

§ 145.22 Elements of a program submission.

(a) Any State that seeks to administer a program under this part shall submit to the Administrator at least three copies of a program submission. For Class VI programs, the entire submission can be sent electronically. The submission shall contain the following:

* * * * *

(5) Copies of all applicable State statutes and regulations, including those governing State administrative procedures;

* * * * *

■ 27. Section 145.23 is amended as follows:

■ a. By revising the introductory text;

■ b. Revising paragraph (c);

■ c. Revising paragraph (d);

■ d. Revising paragraphs (f)(1), (f)(2), (f)(3), (f)(4), and (f)(9); and

■ e. Adding paragraph (f)(13) to read as follows:

§ 145.23 Program description.

Any State that seeks to administer a program under this part shall submit a description of the program it proposes to administer in lieu of the Federal program under State law or under an interstate compact. For Class VI programs, the entire submission can be sent electronically. The program description shall include:

* * * * *

(c) A description of applicable State procedures, including permitting procedures and any State administrative or judicial review procedures.

(d) Copies of the permit form(s), application form(s), reporting form(s), and manifest format the State intends to employ in its program. Forms used by States need not be identical to the forms used by EPA but should require the same basic information. The State need not provide copies of uniform national forms it intends to use but should note its intention to use such forms. For Class VI programs, submit copies of the current forms in use by the State, if any.

* * * * *

(f) * * *

(1) A schedule for issuing permits within five years after program approval to all injection wells within the State which are required to have permits under this part and 40 CFR part 144. For Class VI programs, a schedule for issuing permits within two years after program approval;

(2) The priorities (according to criteria set forth in § 146.9 of this chapter) for issuing permits, including the number of permits in each class of injection well which will be issued each year during the first five years of program operation. For Class VI programs, include the priorities for issuing permits and the number of permits which will be issued during the first two years of program operation;

(3) A description of how the Director will implement the mechanical integrity testing requirements of § 146.8 of this chapter, or, for Class VI wells, the mechanical integrity testing requirements of § 146.89 of this chapter, including the frequency of testing that will be required and the number of tests that will be reviewed by the Director each year;

(4) A description of the procedure whereby the Director will notify owners or operators of injection wells of the requirement that they apply for and obtain a permit. The notification required by this paragraph shall require applications to be filed as soon as possible, but not later than four years after program approval for all injection wells requiring a permit. For Class VI programs approved before December 10, 2011, a description of the procedure whereby the Director will notify owners or operators of any Class I wells previously permitted for the purpose of geologic sequestration or Class V experimental technology wells no longer being used for experimental purposes that will continue injection of carbon dioxide for the purpose of GS that they must apply for a Class VI permit pursuant to requirements at § 146.81(c) within one year of December 10, 2011. For Class VI programs approved following December 10, 2011, a description of the procedure whereby the Director will notify owners or operators of any Class I wells previously permitted for the purpose of geologic sequestration or Class V experimental technology wells no longer being used

for experimental purposes that will continue injection of carbon dioxide for the purpose of GS or Class VI wells previously permitted by EPA that they must apply for a Class VI permit pursuant to requirements at § 146.81(c) within one year of Class VI program approval;

* * * * *

(9) A description of aquifers, or parts thereof, which the Director has identified under § 144.7(b) as exempted aquifers, and a summary of supporting data. For Class VI programs only, States must incorporate information related to any EPA approved exemptions expanding the areal extent of existing aquifer exemptions for Class II enhanced oil recovery or enhanced gas recovery wells transitioning to Class VI injection for geologic sequestration pursuant to requirements at §§ 146.4(d) and 144.7(d), including a summary of supporting data and the specific location of the aquifer exemption expansions. Other than expansions of the areal extent of Class II enhanced oil recovery or enhanced gas recovery well aquifer exemptions for Class VI injection, new aquifer exemptions shall not be issued for Class VI wells or injection activities;

* * * * *

(13) For Class VI programs, a description of the procedure whereby the Director must notify, in writing, any States, Tribes, and Territories of any permit applications for geologic sequestration of carbon dioxide wherein the area of review crosses State, Tribal, or Territory boundaries, resulting in the need for trans-boundary coordination related to an injection operation.

■ 28. Section 145.32 is amended by adding a sentence at the end of paragraph (b)(2) to read as follows:

§ 145.32 Procedures for revision of State programs.

* * * * *

(b) * * *

(2) * * * All requests for expansions to the areal extent of Class II enhanced oil recovery or enhanced gas recovery aquifer exemptions for Class VI wells must be treated as substantial program revisions.

* * * * *

PART 146—UNDERGROUND INJECTION CONTROL PROGRAM: CRITERIA AND STANDARDS

■ 29. The authority citation for part 146 continues to read as follows:

Authority: Safe Drinking Water Act 42, U.S.C. 300f *et seq.;* Resource Conservation and Recovery Act, 42 U.S.C. 6901 *et seq.*

■ 30. Section 146.4 is amended by revising the introductory text and adding paragraph (d) to read as follows:

§ 146.4 Criteria for exempted aquifers.

An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" in § 146.3 may be determined under § 144.7 of this chapter to be an "exempted aquifer" for Class I–V wells if it meets the criteria in paragraphs (a) through (c) of this section. Class VI wells must meet the criteria under paragraph (d) of this section:

* * * * *

(d) The areal extent of an aquifer exemption for a Class II enhanced oil recovery or enhanced gas recovery well may be expanded for the exclusive purpose of Class VI injection for geologic sequestration under § 144.7(d) of this chapter if it meets the following criteria:

(1) It does not currently serve as a source of drinking water; and

(2) The total dissolved solids content of the ground water is more than 3,000 mg/l and less than 10,000 mg/l; and

(3) It is not reasonably expected to supply a public water system.

■ 31. Section 146.5 is amended by revising the first sentence in paragraph (e) introductory text and by adding paragraph (f) to read as follows:

§ 146.5 Classification of injection wells.

* * * * *

(e) *Class V.* Injection wells not included in Class I, II, III, IV or VI. * * *

* * * * *

(f) *Class VI.* 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 § 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 § 146.4 and § 144.7(d) of this chapter.

■ 32. Subpart H is added to read as follows:

Subpart H—Criteria and Standards Applicable to Class VI Wells

Sec.

Subpart H—Criteria and Standards Applicable to Class VI Wells

§ 146.81 Applicability.

(a) This subpart establishes criteria and standards for underground injection control programs to regulate any Class VI carbon dioxide geologic sequestration injection wells.

(b) This subpart applies to any wells used to inject carbon dioxide specifically for the purpose of geologic sequestration, *i.e.,* the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations.

(c) This subpart also applies to owners or operators of permit- or rule-authorized Class I, Class II, or Class V experimental carbon dioxide injection projects who seek to apply for a Class VI geologic sequestration permit for their well or wells. Owners or operators seeking to convert existing Class I, Class II, or Class V experimental wells to Class VI geologic sequestration wells must demonstrate to the Director that the wells were engineered and constructed to meet the requirements at § 146.86(a) and ensure protection of USDWs, in lieu of requirements at §§ 146.86(b) and 146.87(a). By December 10, 2011, owners or operators of either Class I wells previously permitted for the purpose of geologic sequestration or Class V experimental technology wells no longer being used for experimental purposes that will continue injection of carbon dioxide for the purpose of GS must apply for a Class VI permit. A converted well must still meet all other requirements under part 146.

(d) *Definitions.* The following definitions apply to this subpart. To the extent that these definitions conflict with those in §§ 144.3 or 146.3 of this chapter these definitions govern for Class VI wells:

Area of review 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 § 146.84.

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

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

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).

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

Geologic sequestration 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.

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 § 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 § 146.4 and § 144.7(d) of this chapter. 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.

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.

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 § 146.93.

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

Site closure means the point/time, as determined by the Director following the requirements under § 146.93, at which the owner or operator of a geologic sequestration site is released from post-injection site care responsibilities.

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

§ 146.82 Required Class VI permit information.

This section sets forth the information which must be considered by the Director in authorizing Class VI wells. For converted Class I, Class II, or Class V experimental wells, certain maps, cross-sections, tabulations of wells within the area of review 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.

(a) 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, the owner or operator shall submit, pursuant to § 146.91(e), and the Director shall consider the following:

(1) Information required in § 144.31(e)(1) through (6) of this chapter;

(2) A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, 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 faults, if known or suspected. Only information of public record is required to be included on this map;

(3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:

(i) Maps and cross sections of the area of review;

(ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;

(iii) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;

(iv) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);

(v) Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and

(vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.

(4) A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;

(5) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;

(6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;

(7) Proposed operating data for the proposed geologic sequestration site:

(i) Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;

(ii) Average and maximum injection pressure;

(iii) The source(s) of the carbon dioxide stream; and

(iv) An analysis of the chemical and physical characteristics of the carbon dioxide stream.

(8) 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) and that meets the requirements at § 146.87;

(9) Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;

(10) Proposed procedure to outline steps necessary to conduct injection operation;

(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well;

(12) Injection well construction procedures that meet the requirements of § 146.86;

(13) Proposed area of review and corrective action plan that meets the requirements under § 146.84;

(14) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;

(15) Proposed testing and monitoring plan required by § 146.90;

(16) Proposed injection well plugging plan required by § 146.92(b);

(17) Proposed post-injection site care and site closure plan required by § 146.93(a);

(18) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);

(19) Proposed emergency and remedial response plan required by § 146.94(a);

(20) A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and

(21) Any other information requested by the Director.

(b) The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.

(c) Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:

(1) The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section;

(2) Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section;

(3) 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;

(4) The results of the formation testing program required at paragraph (a)(8) of this section;

(5) Final injection well construction procedures that meet the requirements of § 146.86;

(6) The status of corrective action on wells in the area of review;

(7) All available logging and testing program data on the well required by § 146.87;

(8) A demonstration of mechanical integrity pursuant to § 146.89;

(9) Any updates to the proposed area of review 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 submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and

(10) Any other information requested by the Director.

(d) Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.

§ 146.83 Minimum criteria for siting.

(a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:

(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;

(2) 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).

(b) The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

§ 146.84 Area of review and corrective action.

(a) The area of review is 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 is based on available site characterization, monitoring, and operational data.

(b) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:

(1) The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;

(2) A description of:

(i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;

(ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.

(iii) How monitoring and operational data (*e.g.,* injection rate and pressure) will be used to inform an area of review reevaluation; and

(iv) How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.

(c) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:

(1) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:

(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;

(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and

(iii) Consider potential migration through faults, fractures, and artificial penetrations.

(2) Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and

(3) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.

(d) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.

(e) At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:

(1) Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;

(2) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;

(3) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and

(4) Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.

(f) The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.

(g) All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.

§ 146.85 Financial responsibility.

(a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:

(1) The financial responsibility instrument(s) used must be from the following list of qualifying instruments:

(i) Trust Funds.

(ii) Surety Bonds.

(iii) Letter of Credit.

(iv) Insurance.

(v) Self Insurance (*i.e.,* Financial Test and Corporate Guarantee).

(vi) Escrow Account.

(vii) Any other instrument(s) satisfactory to the Director.

(2) The qualifying instrument(s) must be sufficient to cover the cost of:

(i) Corrective action (that meets the requirements of § 146.84);

(ii) Injection well plugging (that meets the requirements of § 146.92);

(iii) Post injection site care and site closure (that meets the requirements of § 146.93); and

(iv) Emergency and remedial response (that meets the requirements of § 146.94).

(3) The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.

(4) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.

(i) Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

(A) Cancellation—for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.

(B) Renewal—for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.

(C) Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.

(5) The qualifying financial responsibility instrument(s) must be approved by the Director.

(i) The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).

(ii) The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.

(iii) The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.

(6) The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.

(i) In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (*e.g.,* well plugging), such combination must be limited to instruments that are not based on financial strength or performance (*i.e.,* self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.

(ii) When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.

(iii) An owner or operator using certain types of third-party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (*e.g.,* surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.

(iv) An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.

(v) An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than −0.1; and a net profit (revenues minus expenses) greater than 0.

(vi) An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.

(vii) An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.

(b) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.

(1) The owner or operator must maintain financial responsibility and resources until:

(i) The Director receives and approves the completed post-injection site care and site closure plan; and

(ii) The Director approves site closure.

(2) The owner or operator may be released from a financial instrument in the following circumstances:

(i) The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of the GS project, if required; or

(ii) The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.

(c) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.

(1) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.

(2) During the active life of the geologic sequestration project, the

owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94).

(3) The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and response plan (§ 146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.

(4) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.

(d) The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.

(1) In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.

(2) A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.

(3) An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.

(e) The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94).

(f) The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.

§ 146.86 Injection well construction requirements.

(a) *General.* The owner or operator must ensure that all Class VI wells are constructed and completed to:

(1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones;

(2) Permit the use of appropriate testing devices and workover tools; and

(3) Permit continuous monitoring of the annulus space between the injection tubing and long string casing.

(b) *Casing and Cementing of Class VI Wells.*

(1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:

(i) Depth to the injection zone(s);

(ii) Injection pressure, external pressure, internal pressure, and axial loading;

(iii) Hole size;

(iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);

(v) Corrosiveness of the carbon dioxide stream and formation fluids;

(vi) Down-hole temperatures;

(vii) Lithology of injection and confining zone(s);

(viii) Type or grade of cement and cement additives; and

(ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.

(2) 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 cement.

(3) 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.

(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.

(5) 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 geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.

(c) *Tubing and packer.*

(1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or

exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.

(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.

(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:

(i) Depth of setting;

(ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;

(iii) Maximum proposed injection pressure;

(iv) Maximum proposed annular pressure;

(v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;

(vi) Size of tubing and casing; and

(vii) Tubing tensile, burst, and collapse strengths.

§ 146.87 Logging, sampling, and testing prior to injection well operation.

(a) 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 § 146.86 and to establish accurate baseline data against which future 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. At a minimum, such logs and tests must include:

(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and

(2) Before and upon installation of the surface casing:

(i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and

(ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.

(3) Before and upon installation of the long string casing:

(i) 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

(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.

(4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:

(i) A pressure test with liquid or gas;

(ii) A tracer survey such as oxygen-activation logging;

(iii) A temperature or noise log;

(iv) A casing inspection log; and

(5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.

(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must 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 Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.

(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).

(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):

(1) Fracture pressure;

(2) Other physical and chemical characteristics of the injection and confining zone(s); and

(3) Physical and chemical characteristics of the formation fluids in the injection zone(s).

(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):

(1) A pressure fall-off test; and,

(2) A pump test; or

(3) Injectivity tests.

(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. 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.

§ 146.88 Injection well operating requirements.

(a) 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. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.

(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.

(c) 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 on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

(d) 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.

(e) The owner or operator must install and use:

(1) Continuous recording devices to monitor: The injection pressure; the rate, 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

(2) Alarms and automatic surface shut-off systems or, at 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

(3) 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.

(f) 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 as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:

(1) Immediately cease injection;

(2) 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;

(3) Notify the Director within 24 hours;

(4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and

(5) Notify the Director when injection can be expected to resume.

§ 146.89 Mechanical integrity.

(a) A Class VI well has mechanical integrity if:

(1) There is no significant leak in the casing, tubing, or packer; and

(2) There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.

(b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);

(c) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:

(1) An approved tracer survey such as an oxygen-activation log; or

(2) A temperature or noise log.

(d) If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.

(e) The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the **Federal Register** and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.

(f) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.

(g) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.

§ 146.90 Testing and monitoring requirements.

The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:

(a) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;

(b) Installation and use, except during well workovers as defined in § 146.88(d), 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;

(c) 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 to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by:

(1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or

(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or

(3) Using an alternative method approved by the Director;

(d) Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:

(1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and

(2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).

(e) A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;

(f) A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;

(g) 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:

(1) Direct methods in the injection zone(s); and,

(2) Indirect methods (*e.g.,* seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;

(h) The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.

(1) Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;

(2) The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter;

(3) If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 *et seq.*) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;

(i) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;

(j) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:

(1) Within one year of an area of review reevaluation;

(2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or

(3) When required by the Director.

(k) A quality assurance and surveillance plan for all testing and monitoring requirements.

§ 146.91 Reporting requirements.

The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:

(a) Semi-annual reports containing:

(1) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

(2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;

(3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;

(4) A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;

(5) 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;

(6) Monthly annulus fluid volume added; and

(7) The results of monitoring prescribed under § 146.90.

(b) Report, within 30 days, the results of:

(1) Periodic tests of mechanical integrity;

(2) Any well workover; and,

(3) Any other test of the injection well conducted by the permittee if required by the Director.

(c) Report, within 24 hours:

(1) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;

(2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(3) Any triggering of a shut-off system (*i.e.,* down-hole or at the surface);

(4) Any failure to maintain mechanical integrity; or.

(5) Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.

(d) Owners or operators must notify the Director in writing 30 days in advance of:

(1) Any planned well workover;

(2) Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and

(3) Any other planned test of the injection well conducted by the permittee.

(e) Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.

(f) Records shall be retained by the owner or operator as follows:

(1) All data collected under § 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.

(2) Data on the nature and composition of all injected fluids collected pursuant to § 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.

(3) Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.

(4) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure.

(5) 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.

§ 146.92 Injection well plugging.

(a) 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.

(b) *Well plugging plan.* The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:

(1) Appropriate tests or measures for determining bottomhole reservoir pressure;

(2) Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;

(3) The type and number of plugs to be used;

(4) The placement of each plug, including the elevation of the top and bottom of each plug;

(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and

(6) The method of placement of the plugs.

(c) *Notice of intent to plug.* The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.

(d) *Plugging report.* Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.

§ 146.93 Post-injection site care and site closure.

(a) 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 that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

(1) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.

(2) The post-injection site care and site closure plan must include the following information:

(i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);

(ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1);

(iii) A description of post-injection monitoring location, methods, and proposed frequency;

(iv) A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,

(v) The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.

(3) Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate.

(4) At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.

(b) The owner or operator shall monitor the site 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.

(1) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.

(2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.

(3) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.

(4) If the demonstration in paragraph (b)(3) of this section cannot be made (*i.e.,* additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.

(c) *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. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.

(1) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:

(i) The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;

(ii) The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;

(iii) The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;

(iv) A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;

(v) The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;

(vi) The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section;

(vii) A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (*e.g.,* carbon dioxide, formation fluids) movement;

(viii) The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;

(ix) A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;

(x) The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and

(xi) Any additional site-specific factors required by the Director.

(2) Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:

(i) All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;

(ii) Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;

(iii) Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;

(iv) Predictive models must be calibrated using existing information (*e.g.,* at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;

(v) Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;

(vi) An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.

(vii) An approved quality assurance and quality control plan must address all aspects of the demonstration; and,

(viii) Any additional criteria required by the Director.

(d) *Notice of intent for site closure.* The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.

(e) 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.

(f) 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. The report must include:

(1) Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;

(2) Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and

(3) Records reflecting the nature, composition, and volume of the carbon dioxide stream.

(g) 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 that will in perpetuity provide any potential purchaser of the property the following information:

(1) The fact that land has been used to sequester carbon dioxide;

(2) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and

(3) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(h) The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.

§ 146.94 Emergency and remedial response.

(a) As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

(b) 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:

(1) Immediately cease injection;

(2) Take all steps reasonably necessary to identify and characterize any release;

(3) Notify the Director within 24 hours; and

(4) Implement the emergency and remedial response plan approved by the Director.

(c) The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.

(d) The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:

(1) Within one year of an area of review reevaluation;

(2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or

(3) When required by the Director.

§ 146.95 Class VI injection depth waiver requirements.

This section sets forth information which an owner or operator seeking a waiver of the Class VI injection depth requirements must submit to the Director; information the Director must consider in consultation with all affected Public Water System Supervision Directors; the procedure for Director—Regional Administrator communication and waiver issuance; and the additional requirements that apply to owners or operators of Class VI wells granted a waiver of the injection depth requirements.

(a) 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. The supplemental report must include the following,

(1) A demonstration that the injection zone(s) is/are laterally continuous, is not a USDW, and is not hydraulically connected to USDWs; does not outcrop; has adequate injectivity, volume, and sufficient porosity to safely contain the injected carbon dioxide and formation fluids; and has appropriate geochemistry.

(2) A demonstration that the injection zone(s) is/are bounded by laterally continuous, impermeable confining units above and below the injection zone(s) adequate to prevent fluid movement and pressure buildup outside of the injection zone(s); and that the confining unit(s) is/are free of transmissive faults and fractures. The report shall further characterize the regional fracture properties and contain a demonstration that such fractures will not interfere with injection, serve as conduits, or endanger USDWs.

(3) A demonstration, using computational modeling, that USDWs above and below the injection zone will not be endangered as a result of fluid movement. This modeling should be conducted in conjunction with the area of review determination, as described in § 146.84, and is subject to requirements, as described in § 146.84(c), and periodic reevaluation, as described in § 146.84(e).

(4) A demonstration that well design and construction, in conjunction with the waiver, will ensure isolation of the injectate in lieu of requirements at 146.86(a)(1) and will meet well construction requirements in paragraph (f) of this section.

(5) A description of how the monitoring and testing and any additional plans will be tailored to the geologic sequestration project to ensure protection of USDWs above and below the injection zone(s), if a waiver is granted.

(6) Information on the location of all the public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review.

(7) Any other information requested by the Director to inform the Regional Administrator's decision to issue a waiver.

(b) To inform the Regional Administrator's decision on whether to grant a waiver of the injection depth requirements at §§ 144.6 of this chapter, 146.5(f), and 146.86(a)(1), the Director must submit, to the Regional Administrator, documentation of the following:

(1) An evaluation of the following information as it relates to siting, construction, and operation of a geologic sequestration project with a waiver:

(i) The integrity of the upper and lower confining units;

(ii) The suitability of the injection zone(s) (*e.g.,* lateral continuity; lack of transmissive faults and fractures; knowledge of current or planned artificial penetrations into the injection zone(s) or formations below the injection zone);

(iii) The potential capacity of the geologic formation(s) to sequester carbon dioxide, accounting for the availability of alternative injection sites;

(iv) All other site characterization data, the proposed emergency and remedial response plan, and a demonstration of financial responsibility;

(v) Community needs, demands, and supply from drinking water resources;

(vi) Planned needs, potential and/or future use of USDWs and non-USDWs in the area;

(vii) Planned or permitted water, hydrocarbon, or mineral resource exploitation potential of the proposed injection formation(s) and other formations both above and below the injection zone to determine if there are any plans to drill through the formation to access resources in or beneath the proposed injection zone(s)/formation(s);

(viii) The proposed plan for securing alternative resources or treating USDW formation waters in the event of contamination related to the Class VI injection activity; and,

(ix) Any other applicable considerations or information requested by the Director.

(2) Consultation with the Public Water System Supervision Directors of all States and Tribes having jurisdiction over lands within the area of review of a well for which a waiver is sought.

(3) Any written waiver-related information submitted by the Public Water System Supervision Director(s) to the (UIC) Director.

(c) Pursuant to requirements at § 124.10 of this chapter and concurrent with the Class VI permit application notice process, the Director shall give public notice that a waiver application has been submitted. The notice shall clearly state:

(1) The depth of the proposed injection zone(s);

(2) The location of the injection well(s);

(3) The name and depth of all USDWs within the area of review;

(4) A map of the area of review;

(5) The names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and,

(6) The results of UIC-Public Water System Supervision consultation required under paragraph (b)(2) of this section.

(d) Following public notice, the Director shall provide all information received through the waiver application process to the Regional Administrator. Based on the information provided, the Regional Administrator shall provide written concurrence or non-concurrence regarding waiver issuance.

(1) If the Regional Administrator determines that additional information

is required to support a decision, the Director shall provide the information. At his or her discretion, the Regional Administrator may require that public notice of the new information be initiated.

(2) In no case shall a Director of a State-approved program issue a waiver without receipt of written concurrence from the Regional Administrator.

(e) If a waiver is issued, within 30 days of waiver issuance, EPA shall post the following information on the Office of Water's Web site:

(1) The depth of the proposed injection zone(s);

(2) The location of the injection well(s);

(3) The name and depth of all USDWs within the area of review;

(4) A map of the area of review;

(5) The names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and

(6) The date of waiver issuance.

(f) Upon receipt of a waiver of the requirement to inject below the lowermost USDW for geologic sequestration, the owner or operator of the Class VI well must comply with:

(1) All requirements at §§ 146.84, 146.85, 146.87, 146.88, 146.89, 146.91, 146.92, and 146.94;

(2) All requirements at § 146.86 with the following modified requirements:

(i) The owner or operator must ensure that Class VI wells with a waiver are constructed and completed to prevent movement of fluids into any unauthorized zones including USDWs, in lieu of requirements at § 146.86(a)(1).

(ii) The casing and cementing program must be designed to prevent the movement of fluids into any unauthorized zones including USDWs in lieu of requirements at § 146.86(b)(1).

(iii) The surface casing must extend through the base of the nearest USDW directly above the injection zone and be cemented to the surface; or, at the Director's discretion, another formation above the injection zone and below the nearest USDW above the injection zone.

(3) All requirements at § 146.90 with the following modified requirements:

(i) The owner or operator shall monitor the groundwater quality, geochemical changes, and pressure in the first USDWs immediately above and below the injection zone(s); and in any other formations at the discretion of the Director.

(ii) 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 direct methods to monitor for pressure changes in the injection zone(s); and, indirect methods (*e.g.,* seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate.

(4) All requirements at § 146.93 with the following, modified post-injection site care monitoring requirements:

(i) The owner or operator shall monitor the groundwater quality, geochemical changes and pressure in the first USDWs immediately above and below the injection zone; and in any other formations at the discretion of the Director.

(ii) 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 direct methods in the injection zone(s); and indirect methods (*e.g.,* seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines based on site-specific geology, that such methods are not appropriate;

(5) Any additional requirements requested by the Director designed to ensure protection of USDWs above and below the injection zone(s).

PART 147—STATE, TRIBAL, AND EPA-ADMINISTERED UNDERGROUND INJECTION CONTROL PROGRAMS

■ 33. The authority citation for part 147 continues to read as follows:

Authority: 42, U.S.C. 300f *et seq.;* 42 U.S.C. 6901 *et seq.*

■ 34. Section 147.1 is amended by adding paragraph (f) to read as follows:

§ 147.1 Purpose and scope.

* * * * *

(f) Class VI well owners or operators must comply with § 146.91(e) notwithstanding any State program approvals.

[FR Doc. 2010–29954 Filed 12–9–10; 8:45 am]

BILLING CODE 6560–50–P