ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 144 and 146

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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: Proposed rule.

SUMMARY: EPA is proposing 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 proposal 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 proposes a new class of well and minimum technical criteria for the geologic site characterization, fluid movement, area of review (AoR) and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, and site closure for the purposes of protecting underground sources of drinking water (USDWs). The elements of this proposal are based on the existing Underground Injection Control (UIC) regulatory framework, with modifications to address the unique nature of CO_2 injection for GS. If finalized, this proposal would help ensure consistency in permitting underground injection of CO_2 at GS operations across the U.S. and provide requirements to prevent endangerment of USDWs in anticipation of the eventual use of GS to reduce CO_2 emissions.

DATES: Comments must be received on or before November 24, 2008. A public hearing will be held during the public comment period in September 2008. EPA will notify the public of the date, time and location of a public hearing in a separate **Federal Register** notice.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OW–2008–0390, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *Mail:* Water Docket, Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460.
- *Hand Delivery:* Water Docket, EPA Docket Center (EPA/DC) EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OW–2008–0390. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected, through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through www.regulations.gov your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. 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, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Water 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 EPA Docket Center is (202) 566–2426.

FOR FURTHER INFORMATION CONTACT: Lee Whitehurst, 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) 564–3896; fax number: (202) 564–3756; e-mail address: *whitehurst.lee@epa.gov.* For general information, contact the Safe Drinking Water Hotline, telephone number: (800) 426–4791. The Safe Drinking Water Hotline is open Monday through Friday, excluding legal holidays, from 10 a.m. to 4 p.m. Eastern time.

SUPPLEMENTARY INFORMATION:

I. General Information

This is a proposed regulation. If finalized, these regulations would affect 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 would include, but are not limited to, the following:

Category	Examples of regulated entities
Private	Operators of CO_2 injection wells used for GS.

This table is not intended to be an exhaustive list, but rather 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 in 146.81 of this proposed rule. 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

AASG American Association of State Geologists
AoR Area of Review
API American Petroleum Institute
$CaCO_3$ Calcium Carbonate
CAA Clean Air Act
CCS Carbon Capture and Storage
CERCLA Comprehensive Environmental Response, Compensation, and Liability Act
CO_2 Carbon Dioxide
CSLF Carbon Sequestration Leadership Forum
DOE Department of Energy

ECBM Enhanced Coal Bed Methane
EFAB Environmental Finance Advisory Board
EGR Enhanced Gas Recovery
EM Electromagnetic
EOR Enhanced Oil Recovery
EPA Environmental Protection Agency
ERT Electrical Resistance Tomography
FACA Federal Advisory Committee Act
GHGs Greenhouse Gases
GS Geologic Sequestration
GWPC Ground Water Protection Council
H_2S Hydrogen Sulfide
ICR Information Collection Request
IEA International Energy Agency
IOGCC Interstate Oil and Gas Compact Commission
IPCC Intergovernmental Panel on Climate Change
LBNL Lawrence Berkeley National Laboratory
LIDAR Light Detection and Ranging
MI Mechanical Integrity
MIT Mechanical Integrity Test
MMT Million Metric Tons
MMV Monitoring, Measurement, and Verification
MPRSA Marine Protection, Research, and Sanctuaries Act
NDWAC National Drinking Water Advisory Council
NETL National Energy Technology Laboratory
NGOs Non-Governmental Organizations
NODA Notice of Data Availability
NPDWR National Primary Drinking Water Regulations
NTTAA National Technology Transfer and Advancement Act
OIRA Office of Information and Regulatory Affairs
OMB Office of Management and Budget
O&M Operation and Maintenance
ORD Office of Research and Development
NO_X Nitrogen Oxides
PFC Perfluorocarbon
PNNL Pacific Northwest National Laboratory
PRA Paperwork Reduction Act
PVT Pressure-Volume-Temperature
PWS Public Water Supply
RA Regulatory Alternative
RCRA Resource Conservation and Recovery Act
RCSP Regional Carbon Sequestration Partnerships
RFA Regulatory Flexibility Act
SACROC Scurry Area Canyon Reef Operators Committee
SBREFA Small Business Regulatory Enforcement Fairness Act
SDWA Safe Drinking Water Act
SO_X Sulfur Oxides
TDS Total Dissolved Solids
UIC Underground Injection Control
UICPG#83 Underground Injection Control Program Guidance # 83
UMRA Unfunded Mandates Reform Act
USDW Underground Source of Drinking Water
VEF Vulnerability Evaluation Framework

Definitions

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

Area of review (AoR): The region surrounding the geologic sequestration project that may be impacted by the injection activity. The area of review is based on computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream.

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 with the well casing.

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 Capture and Storage (CCS): The process of capturing CO_2 from an emission source, (typically) converting it to a supercritical state, transporting it to an injection site, and injecting it into deep subsurface rock formations for long-term storage.

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 outer-most casing that extends from the surface to the base of the lowermost USDW and (2) long-string casing, which extends from the surface to or through the injection zone.

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 that acts as a barrier to fluid movement.

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

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; 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 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) or displaces small amounts of extractable oil and gas, which is then available for recovery. This is also known as secondary or tertiary recovery.

Flapper valve: A valve consisting of a hinged flapper that seals the valve orifice. In GS 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 its capture or transport.

Geologic sequestration project: An injection well or wells used to emplace a CO_2 stream beneath the lowermost formation containing a USDW. It includes the subsurface three-dimensional extent of the carbon dioxide plume, associated pressure front, and displaced brine, 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 carbon dioxide 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 (MIT): 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 before leaks occur.

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 set immediately above the injection zone that seals the outside of the tubing to the inside of the long string casing.

Pinch-out: The location where a porous, permeable formation that is located between overlying and underlying confining formations thins to a zero thickness, and the confining formations are in contact with each other.

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 assure 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: Deep and 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). Saline formations offer great potential CO_2 storage capacity.

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

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 has completed their 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.

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II. What Is EPA Proposing?

EPA is proposing to create a new category of injection well under its existing Underground Injection Control (UIC) Program with new Federal requirements to allow for permitting of the injection of CO_2 for the purpose of GS. Today's proposal builds on existing UIC regulatory components for key areas including siting, construction, operation, monitoring and testing, and closure for injection wells that address the pathways through which underground sources of drinking water (USDWs) may be endangered. The Agency proposes to tailor existing UIC program components so that they are appropriate for the unique nature of injecting large volumes of CO_2 into a variety of geological formations to ensure that USDWs are not endangered.

In addition to protecting USDWs, today's proposed 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.

This proposal does not require any facilities to capture and/or sequester CO_2; rather, this proposal focuses on underground injection of CO_2 and outlines requirements that, if finalized, would protect USDWs under the SDWA. The SDWA provides EPA with the authority to develop regulations to protect USDWs. The SDWA does not provide authority to develop regulations for all areas related to GS. These areas include, but are not limited to, capture and transport of CO_2; determining property rights (i.e., to permit its use for GS and for possible storage credits); transfer of liability from one entity to another; and accounting or certification for greenhouse gas (GHG) reductions. EPA is not proposing regulations for CO_2 under the Clean Air Act (CAA) in this proposed rulemaking.

A. Why Is EPA Proposing To Develop New Regulations To Address GS of CO_2?

1. What Is Geologic Sequestration (GS)?

GS is the process of injecting CO_2 captured from an emission source (e.g., a power plant or industrial facility) into deep subsurface rock formations for long-term storage. It is part of a process known as ''carbon capture and storage'' or 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 fluid (IPCC, 2005). CO_2 exists as a supercritical fluid at high pressures and temperatures, 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, typically by pipeline, or alternatively using tanker trucks or ships (WRI, 2007).

The CO_2 is then injected into deep subsurface rock formations via one or more wells, using technologies that have been developed and refined by the oil and gas and chemical manufacturing industries over the past several decades. To store the CO_2 as a supercritical fluid, it would likely be injected at a depth (greater than approximately 800 meters, or 2,625 feet), such that a sufficiently high pressure and temperature would be maintained to keep the CO_2 in a supercritical state.

When injected in an appropriate receiving formation, CO_2 is sequestered by a combination of trapping mechanisms, including physical and geochemical processes. Physical trapping occurs when the relatively buoyant CO_2 rises in the formation until it reaches a stratigraphic zone with low fluid 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 onto 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. Current research is focused on better understanding these mechanisms and the time required to trap CO_2 under various conditions.

The effectiveness of physical CO_2 trapping is demonstrated by natural analogs worldwide in a range of geologic settings, where CO_2 has remained trapped for millions of years. 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, with no evidence of leakage from the confining formation (IPCC, 2005).

2. Why Is Geologic Sequestration Under Consideration as a Climate Change Mitigation Technology?

Greenhouse gases (GHGs) perform the necessary function of keeping the planet's surface warm enough for human habitation. But, the concentrations of GHGs continue to increase in the atmosphere, and according to data from the National Oceanic and Atmospheric Administration (NOAA) and National Aeronautics and Space Administration (NASA), the Earth's average surface temperature has increased by about 1.2 to 1.4 °F in the last 100 years. Eleven of the last twelve years rank among the twelve warmest years on record (since 1850), with the two warmest years being 1998 and 2005. The Intergovernmental Panel on Climate Change (IPCC) has concluded that much of the warming in recent decades is very likely the result of human activities (IPCC, 2007). The burning of fossil fuels (e.g., from coal-fired electric plants and other sources in the electricity and industrial sectors) is a major contributor to human-induced greenhouse gas emissions.

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 the CO_2 emissions to the atmosphere. The capture and storage of CO_2 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. Given the United States' abundant coal resources and reliance on coal for power generation, CCS could be a key mitigation technology for achieving domestic emissions reductions.

Estimates based on DOE and IEA studies indicate that areas of the U.S. with appropriate geology could theoretically provide storage potential for over 3,000 gigatons (or 3,000,000 megatons; Mt) of geologically sequestered CO_2. Theoretically, this capacity could be large enough to store a thousand years of CO_2 emissions from nearly 1,000 coal-fired power plants. Worldwide, there appears to be significant capacity in subsurface formations both on land and under the seafloor to sequester CO_2 for hundreds, if not thousands of years. CCS technologies could potentially represent a significant percentage of the cumulative effort for reducing CO_2 emissions worldwide.

While predictions about large-scale availability and the rate of CCS project deployment are subject to considerable uncertainty, EPA analyses of Congressional climate change legislative proposals (the McCain-Lieberman bill S. 280, the Bingaman-Specter bill S. 1766, and the Lieberman-Warner bill S. 2191) indicate that CCS has the potential to play a significant role in climate change mitigation scenarios. For example, analysis of S. 2191 indicates that CCS technology could account for 30 percent of CO_2 emission reductions in 2050 (USEPA, 2008a). It is important to note that GS is only one of a portfolio of options that could be deployed to reduce CO_2 emissions. Other options could include efficiency improvements and the use of alternative fuels and renewable energy sources. Today's proposal provides a regulatory framework to protect USDWs as this key climate mitigation technology is developed and deployed. This proposal provides certainty to industry and the public about requirements that would apply to injection, by providing consistency in requirements across the U.S., and transparency about what requirements apply to owners or operators.

Establishing a supporting regulatory framework for the future development and deployment of CCS technology can provide the regulatory certainty needed to foster industry adoption of CCS, which is crucial to supporting the goals of any proposed climate change legislation. This proposed rule is consistent with and supports a strategy to address climate change through: (1) Slowing the growth of emissions; (2) strengthening science, technology and institutions; and (3) enhancing international cooperation. EPA plays a significant role in implementing this strategy through encouraging voluntary GHG emission reductions, and working with other agencies, including DOE, to establish programs that promote climate technology and science.

B. What Is EPA's Authority Under the SDWA To Regulate Injection of CO_2?

Underground injection wells are regulated under the authority of Part C of the Safe Drinking Water Act (42 U.S.C. 300h *et seq.*). The SDWA is designed to protect the quality of drinking water sources in the U.S. and prescribes that EPA issue regulations for State programs that contain ''minimum requirements for effective programs to prevent underground injection which endangers drinking water sources.'' 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 (Section 1421(d)(2) of the SDWA, 42 U.S.C. 300h(d)(2)).

Under this authority, the Agency has promulgated a series of UIC regulations at 40 CFR parts 144 through 148. 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 established 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 Act 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). EPA's authority to regulate GS was further clarified under the Energy Independence and Security Act of 2007, which stated that all regulations must be consistent with the requirements of the SDWA.

Under the SDWA, the injection of any ''fluid'' is subject to the requirements of the UIC program. ''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. Examples of the fluids currently injected into wells 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 (42 U.S.C. 300f *et seq.*). EPA regulates both pollutants and commodities under the UIC provisions; however, today's proposal does not address the status of CO_2 as a pollutant or commodity. In addition, whether or not a fluid could be sold on the market as a commodity is outside the scope of EPA's authority under the SDWA to protect USDWs.

There are limited injection activities that are exempt from UIC requirements including the storage of natural gas (Section 1421(b)(2)(B)) and specific hydraulic fracturing fluids. This exclusion applies to the storage of natural gas as it is commonly defined—a hydrocarbon—and not to injection of other matter in a gaseous state such as CO_2. The Energy Policy Act of 2005 excluded ''the underground injection of fluids or other propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal producing activities.'' A more detailed summary of EPA's authority to regulate the injection of CO_2 can be found in the docket.

Other authorities: Today's proposal applies to injection wells in the U.S. including those in State territorial waters. Wells up to three miles offshore may be subject to other authorities or may require approval under other authorities such as the Marine Protection, Research, and Sanctuaries Act (MPRSA). EPA recently submitted to Congress proposed changes to MPRSA to implement the 1996 Protocol to the London Convention on ocean dumping (the ''London Protocol''). Among the proposed changes is a provision to allow for and regulate carbon sequestration in sub-seabed geological formations under the MPRSA.

C. Who Implements the UIC Program?

Section 1422 of the SDWA provides that States, Territories and federally recognized Tribes may apply to EPA for primary enforcement responsibility to administer the UIC program; those governments receiving such authority are referred to as ''Primacy States.'' Section 1422 requires Primacy States to meet EPA's minimum Federal requirements for UIC programs, including construction, operating, monitoring and testing, reporting, and closure requirements for well owners or operators. Where States, Territories, and Tribes do not seek this responsibility or fail to demonstrate that they meet EPA's minimum requirements, EPA is required to implement a UIC program for them by regulation.

Additionally, section 1425 allows States, Territories, and Tribes seeking primacy for Class II wells to demonstrate that their existing standards are effective in preventing endangerment of USDWs. These programs must include requirements for permitting, enforcement, inspection, monitoring, recordkeeping, and reporting that demonstrate the effectiveness of their requirements.

Thirty-three States and three Territories currently have primacy to implement the UIC program. EPA shares implementation responsibility with seven States and directly implements the UIC Program for all well classes in 10 states, two Territories, the District of Columbia, and all Tribes. At the time of this proposal, no Tribes have been approved for primacy for the UIC Program. However, at the time of this published notice, Fort Peck Assiniboine and Sioux Tribes in EPA Region 8 and the Navajo Nation in EPA Region 9 have pending primacy applications.

Although EPA believes that the most effective approach for the comprehensive management of CO_2 GS projects would be achieved at the State and Tribal level, it is recognized that some injection activities may raise cross-state boundary issues that are beyond the scope of this rulemaking. EPA is aware that some States with primacy for the UIC program are actively engaged in the process of developing their own regulatory frameworks for the GS of CO_2. In some cases, these frameworks include capture, transportation and injection requirements. While EPA encourages States to move forward with initiatives to protect USDWs and public health, it is important to note that States wishing to retain UIC primacy will need to promulgate regulations that are at least as stringent as those that will ultimately be finalized following this proposed rulemaking. In an attempt to reduce uncertainty in this proposed rulemaking, the Agency will keep States apprised of its efforts to establish new Federal UIC GS requirements.

Additionally, EPA seeks comment on any aspects of the ongoing State efforts to regulate the GS of CO_2 and how these efforts might be used to better inform a final Federal rulemaking.

D. What Are the Risks Associated With CO_2 GS?

An improperly managed GS project has the potential to endanger USDWs. The factors that increase the risk of USDW contamination are complex and can include improper siting, construction, operation and monitoring of GS projects. Today's proposal addresses endangerment to USDWs by establishing new Federal requirements for the proper management of CO_2 injection and storage. Risks to USDWs from improperly managed GS projects can include CO_2 migration into USDWs, causing the leaching and mobilization of contaminants (e.g., arsenic, lead, and organic compounds), changes in regional groundwater flow, and the movement of saltier formation fluids into USDWs, causing degradation of water quality.

While the focus of today's proposal is the protection of USDWs, EPA recognizes that injection activities could pose additional risks that are unrelated to the protection of USDWs including risks to air, human health, and ecosystems. The measures taken to prevent migration of CO_2 to USDWs in today's proposal will likely also prevent the migration of CO_2 to the surface. However, regulating such surface/atmospheric releases of CO_2 are outside the scope of this proposal and SDWA authority. A more detailed discussion follows.

Potential USDW Impacts

Injected CO_2 is likely to come in contact with water in the formation fluids of the geologic formations into which it is injected. When CO_2 mixes with water it forms a weak acid known as carbonic acid. Over time, carbonic acid could acidify formation waters potentially causing leaching and mobilization of naturally occurring metals or other contaminants (e.g., arsenic, lead, and organic compounds). CO_2 may also release contaminants into solution by replacing molecules that are sorbed to the surface of the formation, for example, organic molecules such as polycyclic aromatic hydrocarbons (PAHs) in coal beds. The migration of formation fluids containing mobilized contaminants could cause endangerment of USDWs.

Another concern for USDWs is the presence of impurities in the CO_2 stream. These impurities, although a relatively small percentage of the total fluid, could include hydrogen sulfide and sulfurous and nitrous oxides. Because of the volume of CO_2 that could be injected, there may be a risk that co-contaminants in the CO_2 stream could endanger a USDW if the injectate migrates into a USDW. Additionally, when fluids are injected in large quantities, the potential exists for injection to force native brines (naturally occurring salty water) into USDWs.

Improperly operated injection activities may cause geomechanical and/or geochemical effects which may deteriorate the integrity of the initially intact caprock overlying a storage reservoir. For example, injection of CO_2 at high pressure could induce fracturing or could open existing fractures, thereby increasing movement through the caprock and enabling CO_2 to migrate out of the storage reservoir, and potentially into USDWs.

Other Potential Impacts

Human Health: Improperly operated injection activities or ineffective long-term storage could result in the release of injected CO_2 to the atmosphere, resulting in the potential to impact human health and surrounding ecosystems under certain circumstances. While CO_2 is present normally in the atmosphere, at very high concentrations and with prolonged exposure, CO_2 can be an asphyxiant. In addition, direct exposure to elevated levels of CO_2 can cause both chronic (e.g., increased breathing rate, vision and hearing impairment) and acute health effects to humans and animals. Wind speed and direction, topography and geographic location can have a role in the severity of the human health impact of a CO_2 release.

EPA considers that risk of asphyxiation and other chronic and acute health effects from airborne exposure resulting from CO_2 injection activities (even in the case of leakage or accidental exposure) is minimal. This finding is based on experience gained in the oil and gas industry, experience from international GS projects, and evaluations of large scale releases of naturally occurring CO_2.

EPA collected information on the use of CO_2 injection in the oil and gas industry which has decades of experience in drilling through highly pressurized formations and injecting CO_2 for the purpose of enhanced recovery. Internationally, CO_2 has been injected on very large scales at three sites: At Sleipner in the North Sea, at In Salah in Algeria, and in the Weyburn Field in Alberta, Canada (see section E.3 of this document). There have been no documented cases of leakage from these projects, nor has there been release and surface accumulation of CO_2 such that asphyxiation would have been possible.

However, some CO_2 releases from injection activity have been documented. An example of a significant CO_2 leak occurred at Crystal Geyser, Utah. CO_2 and water erupted from an abandoned oil exploration well due to improper well plugging. This well continues to erupt periodically and discharges 12,000 kilotons of CO_2 annually. Studies indicated that within a few meters of the well, CO_2 concentrations were below levels that could adversely affect human health (Lewicki *et al.*, 2006).

EPA also evaluated the occurrence of natural discharges of CO_2 to determine whether such releases could be caused by CO_2 injection or whether injection could result in release of similar magnitudes. Although natural underground CO_2 reservoirs exist throughout the world in volcanically active areas, there are very few instances of rapid discharge of large amounts of CO_2 to the surface (Lewicki *et al.*, 2006). Unusually large and rapid releases of CO_2 from lake bottom storage reservoirs occurred at Lake Nyos and Lake Monoun in Cameroon in the 1980s, causing asphyxiation. These catastrophic events stemmed from a phenomenon known as ''limnic eruption.'' Prolonged high ambient temperatures led to prolonged stratification that allowed naturally occurring CO_2 to slowly accumulate at the bottom of the lakes over many years. Large volumes of CO_2 escaped during an abrupt lake turnover, possibly prompted by volcanic activity.

While lake turnover can bring CO_2 stored in the deepest layers of lake water to the surface almost instantaneously, geologic confining systems do not experience this type of rapid and complete turnover. GS would store CO_2 beneath many layers of rock with a well-defined geologic confining system. Even if a geologic confining system were compromised, any migration of CO_2 towards the surface would not be analogous to a limnic eruption. Pathways for CO_2 leakage from geologic storage reservoirs are generally conductive faults or fractures. In some cases CO_2 may spread diffusely through overlying rocks and soils (Lewicki *et al.*, 2006). None of these conditions is a likely conduit for release of CO_2 on the scale of the releases at Lakes Nyos and Monoun.

Ecosystem: Improperly operated CO_2 injection activities resulting in a release of CO_2 to the atmosphere may have a range of effects on exposed terrestrial and aquatic ecosystems. Due to organisms' varied sensitivities to environmental and habitat changes, certain organisms may be adversely affected at different CO_2 exposure levels. Surface-dwelling animals, including mammals and birds, could be affected similarly to humans when directly exposed to elevated levels of CO_2. The exposure could cause both chronic and acute health effects depending on the concentration and duration of exposure (Benson *et al.*, 2002). Plants, while dependent upon CO_2 for photosynthesis, could also be adversely affected by elevated CO_2 levels in the soil because the CO_2 will inhibit respiration (Vodnik *et al.*, 2006). Soil acidity changes resulting from increased CO_2 concentrations may adversely impact both plant (McGee and Gerlach, 1998) and soil dwelling organisms (Benson *et al.*, 2002). Elevated CO_2 concentrations in aquatic ecosystems can impede fish respiration resulting in suffocation (Fivelstad *et al.*, 2003), decrease pH to lethal levels and reduce the calcification in shelled organisms, and may adversely affect photosynthesis of some aquatic organisms (Turley *et al.*, 2006). The risk of adverse impacts to ecosystems from properly managed CO_2 injection activities is minimal.

Seismic events: Improperly operated injection of CO_2 could raise pressure in the formation, and if too high, injection pressure could ''re-activate'' otherwise dormant faults, potentially inducing seismic events (earthquakes). Rarely, small induced seismic events have been associated with past injection. Before a Federal UIC Program was formed, injection activities at the Rocky Mountain Arsenal in Colorado from 1963 to 1968 induced measurable seismic activity. This incident was the result of poor site characterization and well operation and was among the primary drivers that prompted Congress to pass legislation establishing the UIC Program. Recently, the IPCC (2005) concluded that the risks of induced seismicity are low.

Today's proposal contains safeguards to ensure that potential endangerment to USDWs from CO_2 injection is addressed before the commencement of full-scale GS projects. While preventing releases of CO_2 to the atmosphere is not within the scope of this proposal, today's proposed rulemaking also addresses the risks posed by releases to the atmosphere by ensuring that injected CO_2 remains in the confining formations. The measures outlined in today's proposed rulemaking to prevent endangerment of USDWs may also prevent migration of CO_2 to the surface. A more complete discussion of the potential risks posed by GS is in the *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide (VEF)* (USEPA, 2008b).

E. What Steps Has EPA Taken To Inform This Proposal?

EPA has taken a number of steps to support today's proposal including: (1) Building on the experience of the UIC Program; (2) identifying the risks to USDWs from GS activities; (3) tracking the results on ongoing research; (4) identifying technical and regulatory issues associated with pilot and full-scale GS projects; (5) coordinating with stakeholders on the rulemaking process; and (6) providing guidance and reviewing permits for initial pilot-scale projects.

1. Building on the Existing UIC Program Framework To Specifically Address CO_2 Injection

EPA's UIC regulations prohibit injection wells from causing ''the movement of fluid containing any contaminant into an underground source of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation * * * or may otherwise adversely affect the health of persons'' (40 CFR 144.12(a)). The federal UIC Program has been implemented since 1980 and has responsibility for managing over 800,000 injection wells. The programmatic components of the UIC Program are designed to prevent fluid movement into USDWs by addressing the potential pathways through which injected fluids can migrate into USDWs. These programmatic components are described in general below:

- *Siting:* EPA requires injection wells to be sited to inject into a zone capable of storing the fluid, and to inject below a confining system that is free of known open faults or fractures that could allow upward fluid movement that endangers USDWs.

- *Area of Review (AoR) and Corrective Action:* The Agency requires examination of both the vertical and horizontal extent of the area that will potentially be influenced by injection and storage activities and identification of all artificial penetrations in the area that may act as conduits for fluid movement into USDWs (e.g., active and abandoned wells) and, as needed, perform corrective action to these open wells (i.e., artificial penetrations).
- *Well Construction:* EPA requires injection wells to be constructed using well materials and cements that can withstand injection of fluids over the anticipated life span of the project.
- *Operation:* Injection pressures must be monitored so that fractures that could serve as fluid movement conduits are neither propagated into the layers in which fluids are injected or initiated in the confining systems above.
- *Mechanical Integrity Testing (MIT):* The integrity of the injection well system must be monitored at an appropriate frequency to provide assurance that the injection well is operating as intended and is free of significant leaks and fluid movement in the well bore.
- *Monitoring:* Owners or operators must monitor the injection activity using available technologies to verify the location of the injected fluid, the pressure front, and demonstrate that injected fluids are confined to intended storage zones (and, therefore, injection activities are protective of USDWs).
- *Well Plugging and Post-Injection Site Care:* At the end of the injection project, EPA requires injection wells to be plugged in a manner that ensures that these wells will not serve as conduits for future fluid movement into USDWs. Additionally, owners or operators must monitor injection wells to ensure fluids in the storage zone do not pose an endangerment to USDWs.

Today's proposal builds upon these longstanding UIC programmatic components and tailors them based on the current state of knowledge about the injection of CO_2 for GS purposes. The timeframes involved in preparing and completing each of these components are, in general, project specific (i.e., dependent upon regional geology; location; cumulative injection volumes; additional state and local requirements; industry specificity).

2. Identifying the Risks to USDWs From Injection of CO_2

The existing UIC program provides a foundation for designing a regulatory framework for GS projects that prevents endangerment to USDWs. The Agency has evaluated the risks of CO_2 injection to USDWs to determine how best to tailor the existing UIC regulations to address the buoyant and viscous properties of CO_2 and the large volumes that could be injected.

EPA developed the Vulnerability Evaluation Framework (VEF), an analytical framework that identifies and offers approaches to evaluate the potential for a GS project to experience CO_2 leakage and associated adverse impacts. The VEF is a high-level screening approach that can be used to identify key GS system attributes that should be evaluated further to establish site suitability and targeted monitoring programs. The VEF is focused on the three main parts of GS systems: The injection zone, the confining system, and the CO_2 stream. The VEF first identifies approaches to evaluate key geologic attributes of GS systems that could influence vulnerability to leakage or pressure changes. It then describes an approach to define the area that should be evaluated for adverse impacts associated with leakage or pressure changes. Finally, the VEF identifies receptors that could be adversely impacted if leakage or pressure changes were to occur. The assessment of vulnerabilities to leakage and pressure changes, and of the potential impacts to receptors, is described in a series of detailed decision-support flowcharts. (Some of the impacts addressed in the VEF, e.g., to the atmosphere or ecological receptors, are outside of the scope of today's proposal.) The VEF report (USEPA, 2008b) is included in the docket for this proposed rulemaking.

EPA and the Department of Energy (DOE) are jointly funding the Lawrence Berkeley National Laboratory (LBNL) to study potential impacts of CO_2 injection on ground water aquifers and drinking water sources. As part of the same study, LBNL is also assessing potential changes in regional ground water flow, including displacement of pre-existing saline water or hydrocarbons that could impact USDWs or other resources. EPA and DOE are also jointly funding the Pacific Northwest National Laboratory (PNNL) to perform technical analyses on conducting site assessments, evaluating reservoir suitability, and modeling the flow of injected CO_2 in geologic formations.

3. Tracking the Results of CO_2 GS Research Projects

EPA is tracking the progress and results of national and international GS research projects. DOE leads experimental field research on GS in the U.S. in conjunction with the Regional Carbon Sequestration Partnerships (RCSPs) program. Collectively, the seven RCSPs represent regions encompassing 97 percent of coal-fired CO_2 emissions, 97 percent of industrial CO_2 emissions, 96 percent of the total U.S. land mass, and nearly all the GS sites in the U.S. potentially available for carbon storage. Approximately 400 organizations, including State geologists, industry and environmental organizations, and national laboratories are involved with the RCSPs.

DOE's 2007 Roadmap (DOE, 2007a) describes DOE-sponsored research designed to gather data on the effectiveness and safety of CO_2 GS in various geologic settings through the RSCPs. The Roadmap describes three phases of research, each of which builds upon the previous phase. During the Characterization Phase (2003 to 2005), the partnerships studied regionally-specific sequestration approaches as well as potentially needed regulations and infrastructure requirements for GS deployment. During the Validation Phase (2005–2009), approximately 25 pilot tests will be performed to validate the most promising GS technologies, evaluate regional CO_2 repositories, and identify best management practices for future deployment. During the Deployment Phase (2008–2017), the partnerships will conduct large volume carbon storage tests to demonstrate that large-scale CO_2 injection and storage can be achieved safely and economically. EPA will use the data collected from these projects to support decisions in the final GS rule. Additional information on DOE's research and the partnerships is available at *http://www.fossil.energy.gov/sequestration/partnerships/index.html.*

EPA is also communicating with other research organizations and academic institutions conducting GS research. These institutions include Princeton University, which has a research program for assessing potential problems with degradation of well material from the geologic sequestration of CO_2, and the Massachusetts Institute of Technology, which has a CCS program emphasizing safe and effective future use of coal as a prime energy source.

EPA is also monitoring the progress of international GS efforts. Three projects of note are underway in the North Sea, Algeria, and Canada, whose results are being used to inform today's proposal.

The Sleipner Project, located off the Norwegian coast in the North Sea, is the first commercial scale GS project into a saline formation. Approximately 1 Million tones (Mt) CO_2 is removed annually from the natural gas produced in the Sleipner West Gas Field and injected approximately 800 m (2,625 ft) below the seabed. Injection began in August 1996, and operators expect to store 20 Mt CO_2 over the expected 25-year life of the project. Activities include baseline data gathering and evaluation, reservoir characterization and simulation, assessment of the need and cost for monitoring wells, and geophysical modeling. Seismic time-lapse surveys have been used to monitor movement of the CO_2 plume and demonstrate effectiveness of the cap rock (IPCC, 2005).

The In Salah Gas Project, in the central Saharan region of Algeria, is the world's first large-scale CO_2 storage project in a gas reservoir. CO_2 is stripped from natural gas produced from the Krechba Field and re-injected via three horizontal injection wells into a 1,800 meter-deep (5,906 ft) sandstone reservoir. Approximately 1.2 Mt CO_2 have been injected annually since April 2004 and it is estimated that 17 Mt CO_2 will be stored over the life of the project. To characterize the site, 3-D seismic surveys and well data have been used to map the field, identify deep faults, establish a baseline, and conduct a risk assessment of storage integrity. Monitoring at the site includes use of noble gas tracers, pressure surveys, tomography, gravity baseline studies, microbiological studies, four-dimensional seismic surveys, and geomechanical monitoring (IPCC, 2005).

Weyburn is an EOR project where the CO_2 produced at a coal gasification plant in Beulah, ND is piped to Weyburn in southeastern Saskatchewan for EOR. Approximately 1.5 Mt CO_2 are injected annually via a combination of vertical and horizontal injection wells. It is expected that 20 Mt CO_2 will be stored in the field over the 20 to 25 year life of the CO_2–EOR project. The monitoring regime at the site includes high-resolution seismic surveys and surface monitoring to determine any potential leakage (IPCC, 2005). The conclusions of Phase I of the project are that depleted oil and gas reservoirs from EOR operations are a promising CO_2 storage option and that 4-D seismic monitoring is a valuable tool for plume tracking (IEA, 2005).

Other ongoing GS projects include the Gorgon Gas Development project, a deep saline formation project in Barrow Island, Western Australia; the Otway (Australia) Project, where GS is taking place in a saline formation within a depleted natural gas reservoir; the South Quinshu Basin, China Enhanced Coalbed Methane (ECBM)/CO_2 sequestration project; the CO_2 SINK project in Ketzin, Germany (a sandstone saline formation); and testing of CO_2 GS in the Deccan Trap basalts of India.

4. Identifying Technical and Regulatory Issues Associated With CO_2 GS

EPA has 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.

EPA held a technical workshop on measurement, monitoring, and verification that focused on the availability and utility of various subsurface and near-surface monitoring techniques that may be applicable to GS projects. This workshop, co-sponsored by the Ground Water Protection Council (GWPC), took place in New Orleans, LA on January 16, 2008.

The Agency held a technical workshop on geological considerations for siting and Area of Review (AoR) studies to discuss subsurface geologic information needed to determine whether a site is appropriate for GS; the role of artificial conduits in the AoR on siting decisions; factors that affect the size and shape of the AoR; and corrective actions to address wells in the AoR. Representatives of the RCSPs and the Interstate Oil and Gas Compact Commission (IOGCC) presented their experiences with pilot and experimental GS projects. This workshop took place in Washington, DC on July 10 and 11, 2007.

EPA also held a technical workshop on well construction and MIT that included experimental research in the U.S. and Canada on wellbore integrity and CO_2-cement interactions, modeling, the impact of wellbore integrity on GS site selection, and industry research on well construction. This workshop was held in Albuquerque, New Mexico on March 14, 2007, with participation from the International Energy Association (IEA), an international organization evaluating technical issues associated with CCS.

EPA and DOE collaborated on the State Regulators' Workshop on GS of CO_2 to discuss and formulate the questions related to CO_2 injection that should be addressed in the development of a GS management framework. At this workshop, held in conjunction with the GWPC's UIC Technical meeting in San Antonio, Texas on January 24, 2007, participants identified a set of research questions on the following topics: Site characterization, modeling, AoR, injection well construction, MIT, monitoring, well plugging, post-injection site care, site closure and liability and financial responsibility. The questions they raised set the agenda for future technical workshops as well as established the foundation for today's proposal.

Participants at the International Symposium on Site Characterization for CO_2 Geological Storage, an EPA sponsored meeting with LBNL, held in Berkeley, California on March 20–22, 2006, discussed various aspects of site characterization and selection of potential CO_2 storage sites. The symposium emphasized advances in the site characterization process, development of measurement methods, identification of key site features and parameters, and case studies.

At a workshop on Risk Assessment for Geologic CO_2 Storage, participants discussed the development of a risk assessment framework to identify potential risks related to GS of CO_2 and to consider relevant field experience that could be applicable to injection and long-term storage of CO_2. Some of the key topics addressed at the workshop were: Abandoned wells, faults, and groundwater displacement. This workshop, co-sponsored by GWPC, took place in Portland, Oregon on September 28–29, 2005.

On April 6–7, 2005, EPA held a workshop on Modeling and Reservoir Simulation for Geologic Carbon Storage in Houston, Texas. The topics of this workshop included: An assessment of the potential applications of reservoir models and reservoir simulations to GS; use of models for risk assessments and risk communication throughout the life cycle of a CO_2 storage reservoir; a discussion of areas of new research and data needs to improve the application of modeling and reservoir simulation for carbon storage.

Summaries of the workshops described above are available on EPA's Web site, at *http://www.epa.gov/safewater/uic/wells_sequestration.html.*

5. Stakeholder Coordination and Outreach

Stakeholder participation is an important component of today's proposed rulemaking. EPA held public meetings to discuss EPA's rulemaking approach, met with State and Tribal representatives, and consulted with other stakeholder groups including non-governmental organizations (NGOs), to gain an understanding of stakeholder concerns.

Public Meetings: 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. The December 2007 workshop provided EPA with an opportunity to hear stakeholders' perspectives and concerns. EPA and stakeholders discussed issues including the rulemaking process, existing regulations and regulatory components, statutory authority, GS technology, and technical issues associated with GS. During the February 2008 workshop, EPA provided a comprehensive review of how current UIC program elements could be tailored for the purposes of CO_2 injection for GS. Smaller technical sessions were dedicated to discussion of key questions and considerations related to Area of Review and Site Characterization, Monitoring, Long-term Financial Assurance, and Public Participation. Technical discussions and stakeholder feedback from these workshops were used to inform today's proposal. Summaries of these workshops are available on EPA's Web site, at *http://www.epa.gov/safewater/uic/wells_sequestration.html*.

State and Tribal Meetings: EPA coordinated with the Ground Water Protection Council (GWPC), a State association that focuses on ensuring safe application of injection well technology and protecting ground water resources. In the past several years, GWPC meetings have included sessions on many of the key GS technical and policy issues described above. EPA's participation in these sessions has resulted in a clearer understanding of the regulatory issues associated with the implementation of GS of CO_2.

EPA also coordinated with IOGCC, a chartered State association representing oil and gas producing States. These State members have specific expertise regulating the injection of CO_2 for the enhanced recovery of oil and gas. Additionally, EPA reviewed the IOGCC's model State geologic sequestration regulatory framework to help inform today's proposal.

During the development of the proposed rule, EPA contacted all federally recognized tribes to invite their engagement in the rulemaking process and held a dedicated conference call with the tribes. EPA will continue an ongoing dialogue with interested tribes on this rulemaking.

During the development of the proposed rule, EPA contacted State and local government associations to invite their engagement in the rulemaking process and held a dedicated conference call with their representatives. EPA will continue an ongoing dialogue with interested State and local associations on this rulemaking.

The Agency also held meetings and presented information about the proposed rulemaking to members of the water utility sector. These organizations included the American Water Works Association (AWWA), the Association of Metropolitan Water Agencies (AMWA), and the America Public Power Association (APPA).

In addition, EPA consults with the National Drinking Water Advisory Council (NDWAC), a group that operates under the SDWA to provide advice to EPA's drinking water program and reports to EPA's Administrator. NDWAC consists of members of the general public, drinking water experts, State and local agencies, and private groups concerned with safe drinking water. In support of the proposed rulemaking and in accordance with statutory requirements, EPA consulted with the Department of Health and Human Services. EPA will conduct further consultations prior to finalization of the GS regulation.

The Agency also meets annually with the American Association of State Geologists (AASG) to discuss key topics related to protecting and preserving ground water resources. AASG members are State geologists from around the country who over the past several years have met with EPA to discuss injection-related activities, including CO_2 GS.

Other stakeholder discussions: EPA invited key Non-Governmental Organizations to discuss the potential application of GS as a safe and effective climate change mitigation tool. Attendees of these meetings included Environmental Defense, the National Resources Defense Council, the Clean Air Task Force, the World Resources Institute, and others. In addition, EPA attended and participated in numerous conferences and technical symposia on GS. These meetings, attended by various stakeholders, included sessions on technical issues related to GS and were organized or attended by DOE's National Energy Technology Laboratory (NETL), the American Petroleum Institute (API), the Society of Petroleum Engineers (SPE), and the International Energy Agency (IEA). EPA also attends meetings of the Intergovernmental Panel on Climate Change (IPCC) and events hosted by the World Resource Institute (WRI), including recent meetings focused on long-term liability and frameworks and standards for GS programs.

6. Providing Technical Guidance and Reviewing Permits for Initial Pilot-Scale Projects

EPA issued program technical guidance to assist State and EPA Regional UIC programs in processing permit applications for pilot and other small scale experimental GS projects. This guidance was developed in cooperation with DOE and with States, through GWPC, IOGCC, and other stakeholders. *UIC Program Guidance # 83: Using the Class V Experimental Technology Well Classification for Pilot Carbon Geologic Sequestration Projects* (USEPA, 2007) assists permit writers in evaluating permit applications for pilot-scale GS projects. It clarifies the use of the UIC Class V experimental well classification for GS demonstration projects and provides recommendations to permit writers on how they can issue permits that allow experimental data to be collected while ensuring that USDWs are protected during injection. This guidance will continue to apply to pilot-projects as long as the projects continue to qualify under the guidelines for experimental wells laid out in UICPG #83. It will also remain a permitting option for future projects, as long as new projects are experimental in nature and continue to collect data and conduct research. The program guidance is available at: *http://www.epa.gov/safewater/uic/wells_sequestration.html*. Ultimately, as more, larger GS projects are permitted, EPA anticipates that such projects will not meet the Class V experimental technology criteria. As discussed in the program guidance, such a determination (of Class V or Class VI) is made by the Director.

Currently, EPA Regional and State UIC programs are using this guidance to authorize a number of Class V experimental technology wells. The guidance is being used to help create a nationally consistent permitting framework that draws on the key technical components that affect the endangerment potential of CO_2 GS. These experimental projects will continue to provide EPA and States with critical information that will improve EPA's understanding of the risks posed by CO_2 injection for GS and the operational, technical, and administrative considerations for the advancement and appropriate permitting of this technology. This information will support EPA's final decision on how to regulate GS activities.

F. Why Is EPA Proposing To Develop a New Class of Injection Well for GS of CO_2?

EPA is proposing to establish a new class of injection well for GS projects because CO_2 injection for long-term storage presents several unique challenges that warrant designation of a new well type. When EPA initially promulgated its UIC regulations, the Agency defined five classes of injection wells at 40 CFR 144.6, based on similarities in the fluids injected, construction, injection depth, design, 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 most often the deepest of the UIC wells and are managed with technically sophisticated construction and operation requirements.

Class II wells inject fluids in connection with conventional oil or natural gas production, enhanced oil and gas production, and the storage of hydrocarbons which are liquid at standard temperature and pressure.

Class III wells inject fluids associated with the extraction of minerals or energy, including the mining of sulfur and solution mining of minerals.

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 an approved Federal or State 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 inject below USDWs. This well class includes Class V experimental technology wells including those permitted as geologic sequestration pilot projects.

Today's proposed rulemaking would establish a new class of injection well—Class VI—for GS projects based on the unique challenges of preventing potential endangerment to USDWs from these operations. The Agency invites public comment on the appropriateness of this classification.

G. How Would This Proposal Affect Existing Injection Wells Under the UIC Program?

CO_2 is currently injected in the U.S. under two well classifications: Class II and Class V experimental technology wells. The requirements in today's proposal, if finalized, would not specifically apply to Class II injection wells or Class V experimental technology injection wells. Class VI requirements would only apply to injection wells specifically permitted for the purpose of GS. Injection of CO_2 for the purposes of enhanced oil and gas recovery (EOR/EGR), as long as any production is occurring, will continue to be permitted under the Class II program. EPA seeks comment on the merits of this approach since owners or operators of some Class II EOR/EGR wells may wish to use wells for the purposes of production and GS prior to the field being completely depleted.

Existing wells currently permitted as Class I, Class II, or Class V experimental technology wells could potentially be re-classified for GS of CO_2. However, the owner or operator would need to follow the permitting process outlined in today's proposal to receive a Class VI permit.

EPA is proposing to give the Director discretion to carry over or ''grandfather'' the construction requirements (e.g., permanent, cemented well components) for existing Class I and Class II wells seeking a permit for GS of CO_2, provided he/she is able to make a determination that these wells would not endanger USDWs. Although CO_2 is not currently injected in Class I wells, Class I well construction requirements are similar to those for Class VI. Today's proposal requires that the owner or operator make a demonstration that the well will maintain integrity and stability in a CO_2 rich environment for the life of the GS project. Only the construction requirements would be grandfathered under today's proposal, therefore, Class I or Class II owners or operators seeking to change the purpose of their injection well from Class I or Class II to Class VI would need to meet all other requirements of today's proposed rule (e.g., area of review and site characterization, operating, monitoring, MIT, well plugging, post-injection site care and site closure requirements).

EPA's program guidance on issuing Class V Experimental Technology Well permits (USEPA, 2007) encourages owners or operators and permitting authorities to consider the potential for changing the purpose of demonstration wells to full-scale GS when designing and approving experimental GS projects. EPA understands, based on reviews of several Class V pilot project permits that many of these wells are specifically designed for injection of CO_2 and are being built to Class I non-hazardous well specifications.

Accordingly, EPA is proposing that the Director have the discretion to ''grandfather'' the construction requirements for Class V experimental wells when they are converted to full-scale GS Class VI wells. As with converted Class I and Class II wells, these grandfathered wells would be required to meet the other requirements of today's proposed rule (e.g., operating, monitoring, MIT, well plugging, post-injection site care and site closure).

EPA seeks comment on the approach to grandfather construction requirements at the Director's discretion for existing Class I, Class II, and Class V wells seeking to convert to Class VI wells, and whether additional construction requirements would be necessary to prevent endangerment to USDWs from the GS of CO_2. Additionally, EPA seeks comment on how the grandfathering approach for existing wells may affect compliance with the requirements in this proposal.

H. What Are the Target Geologic Formations for GS of CO_2?

A range of geologic formations is being assessed as potential target formations for receiving and sequestering CO_2. Target formations with the greatest GS capacity include deep saline formations, depleted oil and gas reservoirs, unmineable coal seams, and other formations.

Deep saline formations: Estimates in the Cost Analysis for today's proposal indicate that up to 88.6 percent of the capacity for CO_2 injected for GS is in deep saline formations. These formations are deep and geographically extensive sedimentary rock layers saturated with waters or brines that have a high TDS content (i.e., over 10,000 mg/L TDS). Deep saline formations are found throughout the U.S. and many of these formations may be overlain by laterally extensive, impermeable formations that may restrict upward movement of injected CO_2. All of these characteristics make deep saline formations the leading candidates for GS. Since most deep saline formations have not been extensively investigated, a thorough site-specific characterization of saline formations proposed for GS will be necessary. Such characterizations will need to demonstrate the safety and efficacy of these sites for GS and rule out the presence of fractures, faults, or other characteristics that may endanger USDWs.

Depleted oil and gas reservoirs: Depleted oil and gas reservoirs represent approximately four percent of the potential CO_2 storage capacity in the U.S. and Canada. Because many of these reservoirs have trapped liquid and gaseous hydrocarbon resources for millions of years, EPA believes that they can also be used to sequester CO_2. Hydrocarbons are commonly trapped structurally, by faulted, folded, or fractured formations, or stratigraphically, in porous formations bounded by impermeable rock formations. These same trapping mechanisms can effectively store CO_2 for GS in depleted oil and gas reservoirs.

Oil and gas exploration activities have generated a great deal of geologic data on depleted oil and gas reservoir sites. This information would be directly transferable to the GS site characterization process. Furthermore, models can predict the movement and displacement of hydrocarbons in oil and gas reservoirs and can be used to further advance site specific knowledge about CO_2 storage.

It should also be noted that there are technical challenges associated with GS in depleted oil and gas reservoirs. Injection volumes, operation conditions, and formation pressures for CO_2 injection will differ from those of traditional EOR/EGR operations. The American Petroleum Institute (API) estimates that over 0.6 gigatons (Gt) of CO_2 have been injected for EOR/EGR operations to date and a large percentage of this CO_2 is recovered through production (causing a pressure decrease in the reservoir) (Meyer, 2007). However, DOE estimates that over 90 Gt CO_2 could be geologically sequestered in U.S. oil and gas reservoirs resulting in the potential for reservoir-wide pressure increases.

Depleted oil and gas reservoirs will contain numerous artificial penetrations (e.g., active and abandoned injection and production wells, water wells, etc.) and other types of conduits that could be potential pathways for CO_2 migration. Some of these wells may be decades old, constructed or plugged with materials that may not be able to withstand long-term exposure to CO_2, or may be difficult to locate. Locating and assessing the integrity of these wells and performing appropriate corrective action are essential to assuring that they would not serve as conduits for movement of injected CO_2 or displaced fluids to USDWs.

Unmineable coal seams: Unmineable coal seams represent approximately 1.5 percent of the remaining potential U.S. storage capacity. Currently, enhanced coalbed methane (ECBM) operations exploit the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane, which can then be captured and produced for economic purposes.

Studies suggest that for every molecule of methane displaced in ECBM operations, three to thirteen CO_2 molecules are adsorbed. This process effectively ''locks'' the CO_2 to the coal, where it remains sequestered.

There are a number of technical challenges related to use of coal seams for GS. While coal seams are well studied and understood, the process of CO_2 adsorption to coal has not been proven and the chemical reactions of supercritical CO_2 within coal formations are not well understood. In addition, coals swell as CO_2 is adsorbed, which can reduce the permeability and injectivity of the coal seams, requiring higher injection pressures (IPCC, 2005). There are currently no commercial scale CO_2 ECBM projects, and ECBM with simultaneous CO_2 storage is an emerging technology that is in the demonstration phase (Dooley, *et al.*, 2006; IPCC, 2005). In addition, many ECBM recovery operations will likely be shallow. Shallow storage will result in the CO_2 remaining in a gaseous state, which can limit the amount of CO_2 that can be sequestered. Coal seams and water-bearing formations in close proximity to coal seams may contain less than 10,000 mg/L TDS and meet the definition of a USDW.

EPA is concerned that coal seams in close proximity to USDWs and CO_2 injection for GS could endanger USDWs. In some cases, coal seams are considered USDWs and may serve as public drinking water supplies. As a result, EPA is proposing to preclude the injection of CO_2 for long-term storage into coal seams where they are above the lowermost USDW. EPA requests comment on this proposed prohibition. Today's proposal would not affect injection activities where the primary purpose of the activity is methane production (a Class II activity).

Other formations: Other formations under investigation for CO_2 storage include basalts, salt domes, and shales. These formations are limited in geographic and geologic distribution throughout the U.S., and their technological or economic viability as GS sites have not been demonstrated. In basalts, the injected CO_2 could react with embedded silicate minerals and form carbonate minerals that would be trapped in the basalt. Mined salt domes or salt caverns could be used for CO_2 storage using processes similar to those used by industry to store natural gas (IPCC, 2005). Other abandoned mines (e.g., potash, lead, or zinc deposits or abandoned coal mines) are also CO_2 storage options (IPCC, 2005). CO_2 storage in organic-rich shales, to which CO_2 could adsorb to organic materials in a process similar to coal seam adsorption, is also a possible storage option (DOE, 2007b). The location and proximity of these other formations to USDWs may preclude their use for GS. As with unmineable coal seams, EPA seeks comment on prohibiting injection into such formations if they are above the lowermost USDW.

I. Is Injected CO_2 Considered a Hazardous Waste Under RCRA?

In developing today's proposal, EPA used the Class I industrial well class as the reference for the proposed rule and also considered the potential for hazardous constituents to be present in the injectate, and whether their presence could render the injected CO_2 stream a hazardous waste. The composition of the captured CO_2 stream will depend on the source, the flue gas scrubbing technology for removing pollutants, additives, and the CO_2 capture technology. In most cases, the captured CO_2 will contain some impurities, however, concentrations of impurities are expected to be very low (Apps, 2006).

Because the types of impurities and their concentrations in the CO_2 stream are likely to vary by facility, coal composition, plant operating conditions, and pollution removal technologies, EPA cannot make a categorical determination as to whether injected CO_2 is hazardous under RCRA. Owners or operators will need to characterize their CO_2 stream as part of their permit application to determine if the injectate is considered hazardous as defined in 40 CFR Part 261. If the injectate is considered hazardous under RCRA, then the more stringent UIC Class I requirements for injection of hazardous waste apply. The design changes EPA is proposing are meant to address the mobility and corrosivity caused by long term GS of CO_2, and not the long term storage of hazardous wastes.

By defining ''carbon dioxide stream'' to exclude hazardous wastes (146.81(d)), today's rule, if finalized, assures that it would apply only to CO_2 streams that are not hazardous wastes as defined in 40 CFR Part 261. As a result, today's proposed rule would preclude the injection of hazardous wastes in Class VI injection wells. EPA seeks comment on this approach and other considerations associated with the presence of impurities in the CO_2 stream.

J. Is Injected CO_2 Considered a Hazardous Substance Under CERCLA?

The Comprehensive Environmental Response, Compensation, and Liability

Act (CERCLA), also 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 and the circumstances of their release. It allows EPA to clean up sites contaminated with hazardous substances and seek compensation from responsible parties, or compel responsible parties to perform cleanups themselves. A responsible party may be able to avoid liability through several enumerated defenses, including that the release constituted a ''federally permitted release'' as defined in CERCLA, 42 U.S.C. 9601(10).

While CO_2 itself is not listed as a hazardous substance under CERCLA, the CO_2 stream may contain other substances such as mercury that are hazardous substances or the constituents of the CO_2 stream could react with groundwater to produce listed hazardous substances such as sulfuric acid. Thus, whether or not there is a ''hazardous substance'' that may result in CERCLA liability from a sequestration facility depends entirely on the make-up of the specific CO_2 stream and of the environmental media (e.g., soil, groundwater) in which it is stored. CERCLA exempts from liability certain ''federally permitted releases'' including releases in compliance with a UIC permit under SDWA. Therefore, Class VI requirements and permits will need to be carefully structured to ensure that they do not ''authorize'' inappropriate hazardous releases. This would include clarifying if there are potential releases from the well which are outside the scope of the Class VI permit. EPA requests comment on particular situations where this might occur. EPA also requests comment on other considerations associated with the presence of impurities in the CO_2 stream related to CERCLA.

As applicable, a determination of liability would be made on a case-by-case basis by Federal courts in response to claims for natural resource damages (NRD) or response costs. A NRD claim could be brought by the U.S. or a State or Tribe.

III. Proposed Regulatory Alternatives

The regulatory alternatives for managing CO_2 injection for GS have been informed by the existing UIC program regulations and supplementary contributions from parties with expertise related to the challenges associated with GS of CO_2. In preparing today's proposal, EPA consulted with regulators, industry, utilities, and other technical experts; considered input provided at the technical workshops and stakeholder meetings; and reviewed research, early pilot GS project permits, and IOGCC's model rules and regulations (IOGCC, 2007).

EPA considered four alternatives for developing GS regulations. The four alternatives vary in stringency and specificity as described below.

Alternative 1: Non-specific Requirements Approach. This alternative is the least specific and stringent of the alternatives EPA considered. It includes no specific requirements for site characterization, well construction, or monitoring; rather, it applies a performance standard approach, specifying that GS wells be sited, constructed, operated, maintained, monitored, plugged and closed in a manner that protects USDWs from endangerment.

Alternative 2: General Requirements Approach. This alternative provides more specificity than the previous alternative and includes standards for siting, construction, operation, and monitoring associated with basic deep well design and operation. The general requirements approach also gives permitting authorities flexibility to interpret certain elements in setting permit requirements; however, this alternative does not contain specific program requirements for technical challenges not currently addressed in the UIC Program such as long-term CO_2 storage and large volumes.

Alternative 3: Tailored Requirements Approach. This approach builds on the general requirements approach by incorporating technical standards for deep-well injection of non-hazardous fluids where appropriate and tailoring them to address the challenges of long-term CO_2 storage. This approach also gives permitting authorities discretion in how to permit certain elements and in requiring additional information.

Alternative 4: Highly Specific Requirements Approach. The highly specific requirements approach describes specific technologies and information needed for site characterization, AoR modeling, well construction, monitoring, and testing. Many components of this alternative equal or exceed the requirements for Class I hazardous waste injection wells.

These alternatives are described in more detail in the document, *Regulatory Alternatives for Managing the Underground Injection of Carbon Dioxide for Geologic Sequestration* (USEPA, 2008c).

A. Proposed Alternative

EPA is proposing Regulatory Alternative 3, the Tailored Requirements Approach. The technical requirements of this alternative build upon the existing UIC regulatory framework for deep wells and are appropriately tailored to address the unique nature of full-scale CO_2 GS. The tailored requirements approach promotes USDW protection, incorporates flexibility or the discretion of the permitting authority when appropriate, seeks to limit unnecessary burden on owners or operators or permitting agencies and provides the foundation for national consistency in permitting of GS projects. Because of the volumes of CO_2 being anticipated for long-term storage, the buoyant and viscous nature of the injectate, and its corrosivity when mixed with water, EPA is proposing changes to the existing UIC approach or requirements in several program areas, including site characterization, area of review, well construction, mechanical integrity testing, monitoring, well plugging, post-injection site care, and site closure.

EPA did not select alternative 1 (Non-Specific Requirements Approach) because it does not provide enough specificity to ensure that permitting authorities manage GS wells appropriately to prevent endangerment of USDWs. In addition, this alternative may be burdensome for owners or operators because of the potential for inconsistency across States and burdensome for permitting authorities who will likely be faced with developing their own technical approaches to regulating GS. Alternative 1 could create an uncertain regulatory landscape for owners or operators seeking to operate facilities in multiple states or seeking to manage projects that cross state boundaries.

Although alternative 2 (General Requirements Approach) provides standards for siting, construction, operation, and monitoring associated with basic deep well design and operation, EPA did not select this alternative because it is not tailored to meet the unique challenges of long-term CO_2 storage. While this option includes flexibility for permit authorities to add requirements, EPA cannot be certain that the necessary adjustments would be made.

Alternative 4 (Highly Specific Requirements Approach) lacks the flexibility for incorporating and adapting to evolving GS technologies and provides no clear additional benefits beyond alternative 3 for USDW protection, therefore, EPA did not select this alternative.

1. Proposed Geologic Siting Requirements

Existing UIC requirements for siting injection wells include identification of geologic formations suitable to receive the injected fluids and confine them such that they are isolated below the lowermost USDWs, minimizing the potential for endangerment. While initial assessments indicate there are many geologic formations in the U.S. that can potentially receive injected CO_2, not all can serve as adequate CO_2 GS sites.

A detailed geological assessment is essential to evaluating 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. Thus, EPA is proposing that owners or operators submit maps and cross sections of the USDWs near the proposed injection well.

Injection wells are drilled to a receiving zone, also known as the injection zone. The injection zone is typically a layer or layers of porous rocks, such as sandstone, that can receive large volumes of fluids without fracturing. Today's proposal would require that owners or operators submit data to demonstrate that the injection zone is sufficiently porous to receive the CO_2 without fracturing and extensive enough to receive the anticipated total volumes of injected CO_2. Owners or operators would submit geologic core data, outcrop data, seismic survey data, cross sections, well logs, and other data that demonstrate the lateral extent and thickness, strength, capacity, porosity, and permeability of subsurface formations. The injection zone should be of a sufficient lateral extent that the CO_2 can move a sufficient distance away from the well and still remain in the same zone, without displacing fluids into USDWs. Structural features of a potential injection zone reservoir, such as the lateral extent, dip, or the presence of ''pinch-outs'' (i.e., thinning or tapering out) can affect storage potential, and therefore should be examined.

The injection zone should be overlain by a low permeability confining system (i.e., primary confining zone) consisting of a geological formation, part of a formation, or group of formations that limits the injected fluid from migrating upwards out of the injection zone. The buoyancy of CO_2 necessitates good characterization of potential conduits for fluid migration upward through the confining system to USDWs. The confining system should be of sufficient regional thickness and lateral extent to contain the entire CO_2 plume and associated pressure front under the confining system following the plume's maximum lateral expansion.

EPA proposes that owners or operators of proposed GS projects present to the permitting authority data on the local geologic structure, including information on the presence of any faults and fractures that transect the confining zone and a demonstration that they would not interfere with containment. These data will support determinations about whether these features, if present, could potentially become conduits for movement of CO_2 or other fluids to shallower layers, including USDWs. Under today's proposal, owners or operators must perform and submit the results of geomechanical studies of fault stability and rock stress, ductility, and strength.

Today's proposal would require that owners or operators submit information on the seismic history of the area and the presence and depth of seismic sources to assess the potential for injection-induced earthquakes. These examinations, along with interpretation of geologic maps and cross sections and geomechanical data, are proposed to help rule out sites with unacceptably high potential for seismic activity. Information on in-situ fluid pressures is also required to assess the potential for the pressures associated with injection to reactivate faults or to determine appropriate operating requirements.

A variety of techniques are available to characterize the receiving zones and confining zones of proposed GS sites. For example, geologic core data, test wells, and well logs can help determine rock formations' strength and extent. Seismic and electrical methods can be used to reveal subsurface features. Gravity anomalies indicate density variations at depth, and gravity surveys can be used to locate voids, such as cavities and abandoned mines. Numerous geophysical logging tools can determine formation porosity. Large scale, regional pressure tests can also provide insight into the fluid flow field and the presence and properties of major faults and fractures that may affect flow and transport of CO_2 and displaced brines.

Underground injection wells, if improperly sited and operated, have the potential to induce seismicity, which may cause damage to reservoir and fault seals, creating conduits for fluid movement into USDWs. Today's proposal would require that owners or operators not exceed an injection pressure that would initiate or propagate fractures in the confining zone. To meet this requirement, maximum sustainable injection pressures that will not cause unpermitted fluid movement should be determined prior to CO_2 injection. Estimates of maximum sustainable fluid pressures in CO_2 storage sites are primarily based on predicted changes of effective stresses in rocks during CO_2 injection and associated pore-pressure increase (Streit and Siggins, 2004). Geomechanical studies of fault stability and rock stresses and strength, based on examination and interpretation of geological maps and cross sections, seismic and well surveys, determination of local stress fields, and modeling, can also help rule out sites with unacceptably high potential for seismic activity (IPCC, 2005).

The geochemistry of formation fluids can also affect whether a site is suitable for GS. CO_2 may act as a solvent, and can mix with native fluids to form carbonic acid, which can react with minerals in the formation. Dissolution of minerals may liberate heavy metals into the formation fluids. Reactions may also break down the rock matrix or precipitate minerals and plug pore spaces, therefore reducing permeability (IPCC, 2005). Studies of rock samples and review of geochemical data from monitoring wells are needed to evaluate the impact of these effects. Today's proposal would require owners or operators to submit geochemical data on (a) the injection zone, (b) the confining zones, (c) containment zones above the confining zones in which any potentially migrating CO_2 could be trapped, (d) all USDWs, and (e) any other geologic zone or formation that is important to the proposed monitoring program. The geochemical data are important for identifying potential chemical or mineralogical reactions between the CO_2 and formation fluids that can break down the rock matrix or precipitate minerals that could plug pore spaces and reduce permeability. Additionally, pre-injection geochemical data can serve as baseline data to which results of future monitoring would be compared throughout the injection phase. This information can also improve predictions about trapping mechanisms (which, in turn may improve predictions of pressure changes in the subsurface and the ultimate size of the CO_2 plume).

Today's proposal would provide the Director the discretion to require the owner or operator to identify and characterize additional confining and containment zones above the primary (i.e., lowermost) confining zone that could further impede vertical fluid movement and allow for pressure dissipation. These layers could provide additional sites for monitoring, mitigation, and remediation. Today's proposal would not require that these additional zones be identified for all GS sites because their absence does not necessarily indicate inappropriateness of a GS site. However, if such zones are present, information about their characteristics can provide inputs for predictive models, identify appropriate monitoring locations, and improve public confidence in and acceptance of a proposed GS site. EPA specifically seeks comment on the merits of identifying these additional zones.

2. Proposed Area of Review and Corrective Action Requirements

Delineating the Area of Review: Under the UIC program, EPA established an evaluative process to determine that there are no features near the well such as faults, fractures or artificial penetrations, where significant amounts of injected fluid could move into a USDW or displace native fluids into USDWs. Current UIC regulations require that the owner or operator define the Area of Review (AoR), within which the owner or operator must identify all penetrations (regardless of property ownership) in the confining zone and the injection zone and determine whether they have been properly completed or plugged. The AoR determination is integral to the determination of geologic site suitability because it requires the delineation of the storage operation and an identification and evaluation of any penetrations that could result in the endangerment of USDWs (40 CFR 146.6).

For Class I, II, and III injection wells, Federal UIC regulations require that the AoR be defined as either a fixed radius of ¼ mile surrounding the well (or wells, for an area permit) or an area above the injected fluid and pressure front determined by a computational model. For Class I hazardous waste injection wells, the AoR is defined as a radius of two (2) miles around the well or an area defined based on the calculated cone of pressure influence, whichever is larger.

It is generally agreed that over time, the CO_2 plume and pressure front associated with a full-scale GS project will be much larger than for other types of UIC injection operations, potentially encompassing many square miles. In addition, the complexity of CO_2 behavior in the subsurface may produce a non-circular AoR. It is also possible that multiple owners or operators will be injecting CO_2 into formations that are hydraulically connected, and thus the elevated pressure zones may intersect or interfere with each other. Traditional AoR delineation methods such as a fixed radius or simple mathematical computations would not be sufficient to predict the extent of this movement.

EPA believes that predicting the complex multi-phase buoyant flow of the CO_2, co-injectates, and compounds that may be mobilized due to injection requires the sophistication of computational models. EPA proposes that the owners or operators of GS wells delineate the AoR for CO_2 GS sites using computational fluid flow models designed for the specific site conditions and injection regime.

Multiphase models are the most comprehensive type of computational model available to predict fluid movement in the subsurface under varying conditions or scenarios, and EPA considers them to be appropriate for delineating the AoR for GS projects. This approach was also recommended by IOGCC, workshop participants, and regional and State permit writers for GS operations. EPA seeks comment on the use of modeling for AoR delineation.

Modeling CO_2 Movement and Reservoir Pressure: Computational models used to delineate the AoR consider the buoyant nature and specific properties of separate phases of the injected CO_2 and native fluids within the injection zone. The models should be based on site characterization data collected regarding the injection zone and confining system, taking into account any geologic heterogeneities, and potential migration through faults, fractures, and artificial penetrations.

Appropriate models may incorporate numerical, analytical, or semi-analytical approaches. These models solve a series of governing equations to predict the composition and volumetric fraction (i.e., the fraction of the formation pore-space taken up by that fluid) of each phase state (e.g., liquid, gas, supercritical fluid), as well as fluid pressures, as a function of location and time for a particular set of conditions.

EPA has found that multiphase, computational models are the most appropriate type of computational model to predict the fate and transport of CO_2, co-injectates, and compounds mobilized due to injection. In order to provide guidance related to computational modeling of CO_2 injection for GS, EPA invited expert advice and reviewed relevant technical documents. On April 6–7, 2005, EPA held a workshop on ''Modeling and Reservoir Simulation for Geologic Carbon Storage'' for 60 EPA headquarters and regional staff in Houston, Texas. Computational modeling for AoR determination was also discussed at several additional technical workshops (Section II E). Additionally, the Agency evaluated peer-reviewed journal articles and critical reviews pertaining to computational modeling of CO_2 injection (USEPA, 2008d).

Model results provide predictions of CO_2 fate and transport, as well as changes in formation pressure, in three dimensions as a function of time that can be used to delineate the subsurface storage site and the AoR. Models can also be used to develop monitoring plans, help to evaluate long-term containment, select and characterize suitable storage formations, assess the risk associated with CO_2 leakage and other impacts to USDWs, and to design remediation strategies. Importantly, models can be used to predict CO_2 movement in response to varying conditions or scenarios, such as changing injection rates, or the presence or absence of fractures or faults in confining layers.

Multiphase models have been used by States and industry for predicting the movement of water and solutes in soil, the behavior of non-aqueous phase liquid contaminants (e.g., trichloroethene) at hazardous waste sites, the recovery of oil and gas from petroleum-bearing formations, and more recently, CO_2 in the subsurface. The existing computational codes used to create multiphase models vary substantially in complexity. For example, available codes differ in what processes (e.g., changes of state, chemical reactions) may be included in simulations. As model complexity increases, so does the computational power necessary to use the model, as well as the amount and type of data needed to properly instruct model development. However, more complex models, when properly used, have the potential to provide a more accurate representation of the storage project.

Multiphase models are developed based on a specified set of conditions, such as the formation's geological structure and injection scenario, and inputs describing these conditions are included in an appropriate computational code. Properties of the formation (e.g., permeability, porosity, reservoir entry pressure) and fluids present (e.g., solubility, mass-transfer coefficients), are described by model parameters, the independent variables in the model governing equations that may be constant throughout the domain or vary in space and time. Model predictions depend largely on the values of key parameters. Often these parameter values are estimated or averaged from several data sources.

Models used for GS sites should be based on accepted science and should be validated. In some cases, owners or operators may choose to use proprietary models (i.e., not available for free to the general public). EPA is aware that the use of proprietary codes may prevent full evaluation of model results (e.g., NRC, 2007). Several popular codes in the petroleum-reservoir engineering discipline are proprietary and owners or operators of particular sites may prefer to use these codes as they have previous experience with them, and they have been used in peer-reviewed studies to model CO_2 sequestration. When using a proprietary model, owners or operators should clearly disclose the code assumptions, relevant equations, and scientific basis. EPA seeks comment on allowing the use of proprietary models for GS sites.

Today's proposal does not specify a period of time over which the AoR delineation models should be run. Rather, available models can predict, based on proposed injection rates and volumes and information about the geologic formations, the ultimate plume movement up to the point the plume movement ceases or pressures in the injection zone sufficiently decline.

EPA recognizes that a range of models could be used to delineate the AoR and that some of these models may have been in use for some time. Models currently used to delineate AoR, regardless of age, are considered computational and may be appropriate for use in determining the AoR for GS of CO_2. However, EPA anticipates that modeling technology will improve substantially, and encourages and expects owners or operators to use the best multiphase computational models available to determine the AoR. Reliance on improved models will likely increase the accuracy and quality of the AoR characterization, resulting in better protection of USDWs.

Model simulations and site monitoring are interdependent, and comprise an iterative, cyclical system. Model simulations can be used for an initial prediction of injected fluid movement to identify the type, number and location of monitoring points. As data are collected at an injection site, model parameters can be adjusted to match real-world observations (i.e., model calibration or history-matching), which in turn improves the predictive capability of the model. Additionally, model simulations are adjusted over time to reflect operational changes. Project performance is thus evaluated through a combination of site monitoring and modeling.

EPA seeks comment on the applicability of computational fluid flow models for delineating the AoR of GS sites.

Corrective Action: Today's proposal would require that owners or operators of GS wells identify all artificial penetrations in the AoR (including active and abandoned wells and underground mines). This inventory and review process is similar to what is required of Class I and Class II injection well operators.

The owner or operator would compile, tabulate, and review available information on each well in the AoR that penetrates into the confining system, including casing and cementing information as well as records of plugging. If additional confining zones are identified, wells penetrating those additional zones would be included in this review. Based on this review, the owner or operator 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. In the event that an owner or operator cannot perform the appropriate corrective action, the Director would have discretion to modify or deny the permit application. Corrective action could be performed prior to injection or on a phased basis over the course of the project (as outlined in the next section). Available corrective action techniques include plugging of offset wells or monitoring in the injection zone. Another example of corrective action is remedial cementing, in which owners or operators would squeeze cement into channels or voids between the casing and the borehole, to prevent upward migration along uncemented casing.

Today's proposal does not prescribe the specific cements to be used to plug abandoned wells in the AoR because industry standards, such as those developed by API or ASTM International, reflect the current state of the science and the expertise of industrial users on corrosion-resistant materials.

Though today's proposal does not dictate specific corrective action methods, it requires that the corrective action methods be appropriate to the CO_2 injection. At the Technical Workshop on Geological Considerations and AoR Studies, participants generally concluded that the reaction of the CO_2 injectate stream with typical well materials and cements that are likely to be encountered in abandoned wells in the AoR is an important consideration. Today's proposal would require that corrective action for wells in the AoR of GS projects be performed with appropriate corrective action methods such as use of corrosion-resistant cements.

Area of Review Reevaluation: Predicting the behavior of injected CO_2 in the subsurface, particularly the ultimate extent of a CO_2 plume and associated area of elevated pressure in a laterally expansive reservoir, poses uncertainties. Today's proposal would require that the owner or operator periodically reevaluate the AoR during the injection operation. Reevaluations would occur at a minimum fixed frequency, not to exceed 10 years, as agreed upon by the Director.

When monitoring data differ significantly from modeled predictions, or when there are appreciable operational changes (e.g., injection rates), reevaluation may be mandated prior to the minimum fixed frequency. At no time would area of review reevaluations occur less frequently than every 10 years.

Reevaluations of the AoR would be based on revision and calibration of the original computational model used to delineate the AoR. If site monitoring data agrees with the existing AoR delineation, a model recalibration may not be necessary. In these cases, an AoR reevaluation may consist simply of a demonstration that the current AoR delineation is adequate based on site monitoring data.

There are many potential benefits to periodically reevaluating the AoR. Each revised model prediction would estimate the full extent of the CO_2 plume and area of elevated pressure; however, the near-term predictions (e.g., over the subsequent 10 years) would have the highest degree of certainty and could be the basis of corrective action. Re-running the models would allow refinement to the AoR delineation based on real-world conditions and monitoring results, and thus increase confidence in the modeled predictions. The revised model predictions would also be used to identify monitoring sites so that monitoring would occur in any areas subject to the greatest potential risk.

EPA seeks comment on requiring the reevaluation of the site AoR on a periodic basis, under what conditions the AoR should be reevaluated, and the appropriateness of a 10 year minimum fixed frequency for AoR reevaluation.

Phased Corrective Action: In the UIC program, corrective action is typically performed on all wells in the AoR in advance of the injection project. Today's proposal recognizes that this may not always be appropriate for GS projects. The AoR for a GS site may be quite large, requiring considerable time and resources to perform corrective action on all wells that may eventually be affected by the GS project over the course of decades of injection. In addition, if the periodic reevaluations of the AoR indicate that the AoR has grown or shifted to areas not originally included, additional wells may need to be identified for potential corrective action.

Today's proposal would give the Director the discretion to allow owners or operators to perform corrective action on an iterative, phased basis over the operational life of a GS project. Prior to injection, the owner or operator would identify all wells penetrating the confining or injection zone within the site AoR. However, the owner or operator may limit pre-injection corrective action to those wells in the portion of the AoR that would be intersected by the CO_2 plume or pressure front during the first years of injection. As the project continues and the plume expands, the owner or operator would continue to perform corrective action on wells further from the well to assure that all wells in the AoR that need corrective action eventually receive it. This approach would ensure that any necessary corrective action is taken in advance of the CO_2 plume and associated area of elevated pressure approaching USDWs.

There are potential benefits to implementing phased corrective action. Phasing in the corrective action would benefit the owner or operator by spreading out the burden and costs of corrective action and not delaying initiation of the GS project while corrective action is performed at wells that may not be affected by the injection for several decades. Initial corrective action would focus on those penetrations that pose a potential endangerment to USDWs from injection of CO_2 in the near term. Deferring corrective action on some of the wells at the outer reaches of the predicted plume can improve USDW protection by giving these later corrective action efforts the benefit of newer corrective action techniques. Additionally, this approach can prevent the unnecessary burden of performing corrective action in areas far from the injection zone that may never be impacted. This approach would still assure that all wells in the AoR that need corrective action eventually receive it, as is the case in current UIC requirements.

Participants at the technical workshops on ''Geological Considerations and AoR Studies'' and ''Modeling and Reservoir Simulation for Geologic Carbon Storage'' agreed that the AoR should be reevaluated over time based on incoming monitoring and site characterization data. In addition, participants at the February 2008 Stakeholder Workshop generally supported reevaluation of the AoR and a phased corrective action approach.

EPA recognizes that a phased approach to corrective action may not be appropriate in all situations; therefore EPA is proposing that the Director have the discretion to decide to allow this approach, based on the understanding of relevant geologic and site conditions. EPA invites public comment on the merits and frequency of reevaluation of the AoR as well as the phased corrective action approach for GS wells.

Proposed Area of Review and Corrective Action Plan: For typical UIC wells, the AoR is delineated only once, and corrective action on all wells in the AoR is performed prior to commencing injection. However, AoR and corrective action for GS wells will involve multiple steps over many years, so EPA proposes that the owner or operator of a GS well submit an AoR and corrective action plan as part of their permit application. After approved by the Director, the owner or operator would implement the plan.

In the AoR and corrective action plan, the owner or operator would describe plans to delineate the AoR, including the model to be used, assumptions made, and the site characterization data on which the modeling would be based. It would include a strategy for the owner or operator to periodically reevaluate the AoR in response to operational changes (e.g., injection rates), when monitoring data varies from modeled predictions, or at a minimum fixed frequency, not to exceed 10 years, as agreed upon by the Director. It should describe what monitoring data would be used to determine whether the AoR needs to be adjusted and how that data would be incorporated into the model. A description of how the public would be informed of changes in the AoR would be included.

The AoR and corrective action plan would also specify where corrective action would be performed prior to injection, what, if any areas would be addressed on a phased basis, and how the timing of each phase of corrective action would be determined. In addition, the plan would identify how site access would be guaranteed for areas requiring future corrective action, and how corrective action may change to address potential changes in the AoR.

EPA also proposes that, as owners or operators periodically reevaluate the AoR delineation, they must either amend the Director-approved AoR and corrective action plan (i.e., to perform additional corrective action) or report to the Director that no changes to the plan are necessary. This approach promotes continued communication between the Director and the owner or operator regarding expectations over the long duration of CO_2 injection, and assures that the AoR delineation methodology reflects local conditions. The proposed requirement to periodically revisit the modeling effort, which was advocated by stakeholders, would help to verify that the CO_2 plume is moving as predicted and provides an opportunity to adjust the injection operation and corrective action to address changes in the predicted AoR. The reevaluation process would also help account for new wells in the AoR.

3. Proposed Injection Well Construction Requirements

Well Construction Procedures: Properly constructing an injection well is a technologically complex yet well understood undertaking. An appropriately designed and constructed well would prevent endangerment to USDWs and would maintain integrity throughout the lifetime of the project, from the injection operation period through and beyond the post-injection site care period once the well is permanently plugged. Current drilling and well construction practices for CO_2 injection wells are based on existing knowledge and practices from the oil and gas industry.

A typical well is constructed by placing multiple strings of high strength steel alloy or fiberglass concentric pipe and tubing into a drilled wellbore. Typically, the first step in well construction is the drilling of a large borehole (e.g., 10″ to 30″) through the base of the lowermost USDW. A large diameter pipe, termed surface casing, is then placed in the wellbore to protect shallow aquifers or underground sources of drinking water during the drilling and injection phases. This casing is usually cemented by circulating cement between the outside of the surface casing and the side of the borehole to ensure that the wellbore is stabilized, that the casing is completely sealed to the rock of the wellbore, and that the geologic formations are isolated from each other and the surface.

Next, a smaller diameter wellbore (e.g., 7″ to 15″) is drilled further downwards, into the injection zone, and a smaller diameter pipe, usually designated as the long-string casing, is run into the hole. Similar to the surface casing, the long-string casing is cemented in place to the borehole by circulating cement from the bottom back up to the surface casing, filling the gap between the outside of the long-string casing and the wellbore. This cementing process again ensures that rock formations are isolated and no fluid movement occurs between formations.

Depending on the depth to the injection formation, additional strings of casing may be necessary, but in each case, these casings are engineered and designed to withstand internal and external pressures at depth. The final result is multiple barriers of cement and casing between formations above the injection zone and the fluids being injected. Typically a portion of the wellbore in the injection zone is left open or the casing is perforated to allow injected fluid to enter into the injection zone.

Inside the long string casing, injection tubing is run from the surface to a depth within the injection zone. This tubing may be engineered of steel, an alloy, fiberglass, or a composite material most suitable for the injectate's composition. The tubing extends from the wellhead down to the storage zone where it is sealed by a mechanical device known as a packer. The area between the tubing and long string casing is isolated and the fluid injected into the well can only enter the geologic formation for which it is targeted. With this type of well construction, the fluid within the well tubing has minimal contact with the components of the well that protect USDWs.

The space between the injection tubing and the long string casing and above the packer is called the annulus. The annulus between the wellhead and the packer is a water-tight space filled with a non-corrosive fluid that helps to protect the inside of the casing and outside of the tubing from damage due to chemical reactions. In addition, monitoring the pressure of the annulus using standard pressure devices can easily detect any leaks in the tubing, long string casing, or packer.

Due to the buoyancy of CO_2, today's proposal includes enhancements to typical deep well construction procedures to provide additional barriers to CO_2 leakage outside of the injection zone. The proposal would require that surface casing for GS wells be set through the base of the lowermost USDW and cemented to the surface. The long-string casing would be cemented in place along its entire length. GS wells would also be constructed with a packer that is set opposite a cemented interval, at a location approved by the Director. EPA seeks comment on the proposed GS well requirements for depth of surface casing, the cementing of long-string casing, and construction with a packer set opposite a cemented interval. EPA also seeks comment on how the proposed grandfathering provisions for existing wells (construction requirements) may affect compliance with the above, proposed construction requirements.

More information on well drilling may be found by consulting various sources including the Department of Energy, the American Petroleum Institute (API), and the Society of Petroleum Engineers (SPE). Please consult information or links on EPA's Web site: *http://www.epa.gov/safewater/uic.html*, or similar sources.

Horizontal Well Construction: While horizontal well construction is not typical in deep injection wells in the UIC program, there are examples of horizontal well completions being used with success to improve the production of EOR and ECBM operations (e.g., Westermark *et al.*, 2004; Sams *et al.*, 2005). EPA understands that the In Salah project in Algeria is using horizontal well construction for GS purposes. Horizontal wells are constructed by use of a directional drilling system, which generally consists of both a curve and lateral drilling assembly. After the vertical portion of the well is constructed, the curve drilling assembly is used to drill a curve of prescribed radius to change the path from vertical to horizontal. The lateral drilling assembly is then used to construct the horizontal section, which can be lined or remain as an open hole. Importantly, several horizontal sections can be completed stemming from a single vertical completion.

The use of horizontal wells for a GS project could provide several benefits over vertical wells. Horizontal wells provide enhanced connectivity with permeable sections of the formation, increasing injectivity. The use of horizontal wells increases the sweep, or formation contact area, of the injected CO_2 plume, as vertical channeling through high permeability regions is reduced. Increasing the sweep results in enhanced residual-phase CO_2 trapping and dissolution favorable for the purposes of permanent storage. Horizontal wells also reduce the pressures needed to inject any given volume of fluid. In addition, fewer vertical completions are required with the use of horizontal wells, which reduces the number of artificial penetrations in the formation through which fluid could migrate, as well as reducing overall costs.

EPA seeks comment on the merits of horizontal well drilling techniques for GS wells and the applicability of well construction requirements discussed in this proposal.

Well Component Degradation: The potentially corrosive nature of the injectate must be taken into consideration in the design and construction of CO_2 GS wells. The quality of the well materials, proper well construction, composition and placement of appropriate cement along the wellbore, and appropriate maintenance are crucial, because a leaking annulus would be a significant route of escape for CO_2 (IPCC, 2005).

CO_2 mixed with water or impurities (NO_X, SO_X and H_2S) can be corrosive to well materials and cements. Conventional cement formulations (e.g., Portland cement) are potentially vulnerable to acid attack. Acid attack on the calcium carbonate in cement can lead to altered permeability and mechanical instability. Defects in the well cement, such as channels, cracks, and microannuli (i.e., small spaces between the casing and cement) can provide pathways for acid to migrate and accelerate degradation.

Experience with CO_2 injection for EOR includes the use of acid-resistant cements. Cements with a reduced Portland content are more resistant to acid because they contain less calcium carbonate ($CaCO_3$). Acid resistant cements can be formulated by adding fly ash, silica fume (microsilica), latex, epoxy, or other substances. Calcium phosphate cement is a blend of high-alumina cement, phosphate, and fly ash that can retain integrity under conditions where other cements lose a substantial portion of their weight, according to one manufacturer (*http://www.eandpnet.com/area/exp/153.htm*).

EPA examined available information to determine the rate at which cement degrades in acidic environments. Laboratory studies provide evidence of deterioration of cement and other well components due to exposure to acid. For example, Duguid *et al.*, (2004) performed a laboratory study in which Portland cement experienced significant damage within seven days. Similar experiments by Kutchko *et al.*, (2007) showed less cement alteration. Differences between these studies may be due to different experimental conditions, such as temperature and pressure.

Limited results of field studies show clear evidence of reactions between CO_2 and well cement, but do not show such severe corrosion. Cement samples from a well at the Scurry Area Canyon Reef Operators Committee (SACROC) site did not show serious degradation (Carey *et al.*, 2007). In another study, cement samples were collected and analyzed from a CO_2 production well in a natural CO_2 reservoir in Colorado exposed to a CO_2-water environment for 30 years (Crow *et al.,* 2008). The study found considerable reactions between the CO_2 and cement, and CO_2 migration up the wellbore along the cement-formation interface. However, the cement alteration was not significant enough to enable CO_2 migration through the cement itself and the distance of CO_2 migration along the cement-formation interface was very limited. Although the field corrosion looks surprisingly low, these are only limited examples. Laboratory studies are conducted under aggressive chemical conditions in an attempt to mimic the cumulative effects of long-term exposure to CO_2-rich formation fluids. Given the high injection rates, long lifespan, and potential impurities in GS, careful selection of acid-resistant materials and practices may be necessary.

Metal components of the injection well, such as carbon steel, are subject to corrosion. To minimize problems, Meyer (2007) recommends the use of Grade 316 stainless steel. One company working on GS projects indicates that they use stainless steel well casing to avoid corrosion problems (Buller *et al.,* 2004). Stainless steels consist of iron, small amounts of carbon, and at least 10 percent chromium. Grade 316 stainless steel also contains molybdenum, which endows it with corrosion resistance in a variety of corrosive media, although it is subject to corrosion in warm chloride environments and to stress corrosion cracking at warmer temperatures (above 60 degrees C). According to the report, recovered CO_2 injection well components at the SACROC site in Texas were made of Grade 316 stainless steel and did not exhibit signs of corrosion. Industry representatives at the Technical Workshop on Well Construction and MIT noted that many casing options (e.g., titanium and fiberglass casing) are available. Useful packer products include swell-resistant elastomer materials such as Buna-N and Nitrile rubbers (Meyer, 2007). Teflon and nylon are options for anti-corrosion seals.

The use of corrosion-resistant materials is crucial to the success of long-term GS operations. UIC program experience, industry experience, and stakeholder input suggest that appropriate materials are available. Today's proposal does not specify materials that may be used, rather, proposes providing the owner or operator with the flexibility to choose, as long as the materials used in GS wells are corrosion-resistant and meet or exceed standards developed for such materials by API or ASTM International, or comparable standards approved by the Director. Well materials must be compatible with injected fluids, including any co-injected impurities or additives, throughout the life of the project, and be appropriate for the well's depth, the size of the well bore, and the lithology of injection and confining zones.

GS projects are anticipated to have long lifespans in comparison to other types of deep injection wells. Not only must GS wells be able to function safely and properly over the lifespan of the GS project, but they must be constructed such that USDWs remain protected after well plugging. Today's proposal would require that the cements and cement additives used in GS wells be appropriate to address long-term injection of CO_2 and assure that the well can maintain integrity throughout the proposed life span of the project, including the post-injection site care period and beyond once the well is permanently plugged. Owners or operators must use corrosion-resistant cement approved by the Director and be able to verify the integrity of the cement using logs or other acceptable methods.

EPA seeks comment regarding requirements for degradation-resistant well construction materials, such as acid-resistant cements and corrosion resistant casing.

4. Proposed Injection Well Operating Requirements

EPA's operating requirements for deep injection wells provide multiple safeguards to ensure that injected fluids do not escape and are confined within the injection zone and that the integrity of the confining zone is not compromised by non sealing artificial penetrations or geologic features. In today's proposal, some well operating requirements are consistent with existing UIC well types and some requirements are tailored specifically for CO_2 injection.

Injection Parameter Limitations: Limitations on injection parameters are intended to prevent the movement of injected or other fluids to USDWs via fractures in confining layers or vertical migration. In order to drive the injected fluids away from the well and into the formation, fluids must be injected at a higher pressure than the pressure of fluids in the injection zone. However, the sustained pressure should not be as high as fracture pressure, that is, high enough to initiate or propagate fractures in the injection or confining zone. If the pressure within the reservoir becomes high enough, induced stresses may reactivate existing faults (Rutqvist *et al.,* 2007), though injection pressure limitations may be employed to prevent this (Li *et al.,* 2006). Several geomechanical methods are available to assess the stability of faults and estimate maximum sustainable pore fluid pressures for CO_2 storage. For example, one way of deriving these is to calculate the effective stresses on faults and reservoir rocks based on fault orientations, pore fluid pressures, and in-situ stresses (Streit and Hillis, 2004).

Today's proposal would require an injection pressure limitation similar to existing UIC Class I deep well requirements. Owners or operators of GS wells must limit CO_2 injection pressures, except during well stimulation, so that injection does not initiate new fractures, propagate existing fractures in the injection zone, or cause movement of injection or formation fluids that endanger USDWs. Under this proposal, during injection, the pressure in the injection zone must not exceed 90 percent of the fracture pressure of the injection zone. Calculation of fracture pressure is fundamental to evaluating the appropriateness of the site. The 90 percent requirement, suggested by permit writers and IOGCC, provides an added margin of safety in the well operation.

There are some circumstances, however, where fracturing of the injection zone would be acceptable provided the integrity of the confining system remains unaffected. For example, hydraulic fracturing is a process where a fluid is injected under high pressure that exceeds the rock strength, and the fluid opens or enlarges fractures in the rock. EPA recognizes that there may be well completions which require intermittent treatments, including hydraulic fracturing of the injection zone, to improve wellbore injectivity. Such stimulation of the injection zone during a well workover (as defined in 40 CFR 144.86(d)) approved by the Director would be permissible.

Fracturing of the confining zone would be prohibited at all times during injection and/or stimulation.

It is also possible that CO_2 GS may be associated with ECBM, where more extensive hydraulic fracturing would be necessary to open pre-existing fractures in the coal and provide additional surfaces onto which CO_2 may adsorb and to extract methane. These hydraulic fracturing operations are used to enhance oil and gas recovery and for ECBM recovery, and in general are exceptions to the definition of underground injection under the SDWA.

EPA is requesting comment on the extent and scope to which hydraulic fracturing should be allowed during GS injection, and whether the use of fracturing for the purposes of well stimulation is appropriate. EPA is also requesting information to better qualify the use of fracturing for GS injection in specific geologic settings and rock formation lithologies.

Continuous Monitoring: Monitoring within the injection well system is important to assure that the injection project is operating within permitted limits. It can also protect the owner or operator's investment, as significant divergences in any of these parameters could damage well components. Deep injection well owners or operators typically monitor injection pressure, flow rate, temperature, and volumes. Owners or operators usually choose to maintain pressure on the annulus between the tubing and the long string casing and monitor this pressure to ensure protection of USDWs from well leakage. Monitoring is generally performed on a continuous basis, through the use of automated equipment that typically takes readings several times per minute and records them in a computer system.

Alarms and automatic shut-off devices connected to the monitoring equipment can engage if operational limits are exceeded. Available computer-driven monitoring systems have the ability to continuously monitor injection parameters and engage the shut-off devices. Though these systems are not required for all UIC well classes, the complexity of GS operations and the potential for movement of the CO_2 in the event of a mechanical integrity loss makes a shut-off system an important safety consideration for GS projects.

Traditionally, owners or operators have installed monitoring and shut-off equipment at the wellhead (i.e., at the surface), however, down-hole devices have been used in offshore applications for several years. Today's proposal requires that automatic shut-off valves be installed down-hole in addition to at the surface. This requirement is supported by many participants at the technical workshops and the IOGCC's recommendations.

The down-hole valves provide a safety backstop in case damage to the wellhead prevents the proper operation of wellhead shut-off valves. Direct pressure measurements used to trigger shut-off devices are more accurate than wellhead calculations of down-hole pressure. The down-hole valves are an integral part of the tubing string and can be positioned anywhere along the tubing string. Gauges can be either inside or outside of the casing; installation on the outside of the casing may cause less interference with well maintenance. The down-hole valves are kept in an open position by hydraulic pressure from a connection to the surface. Damage to the wellhead or an upset in operations causes the positive hydraulic pressure to fall, forcing the valve into a ''failsafe'' closed position. In case of well failure, a down-hole shut-off device would isolate the injectate below USDWs, rather than just below the surface. By engaging near the injection zone, they can prevent pressure-induced damage to the well casing. This would also require less expensive repairs if pressure exceedances were to occur.

While there would be some cost and downtime associated with replacing failed down-hole valves, such costs are considered small in comparison to the costs if large amounts of CO_2 should escape into USDWs or to the surface. It is possible to place a new valve down-hole without removing the existing valve, so downtime can be minimized if an appropriate parts inventory is kept on hand. A Norwegian study found that the failure rate of down-hole safety valves was 2 failures per million operating hours (Norwegian Oil Industry Association, 2001). This is a relatively low failure rate as the valves are designed to withstand harsh conditions and operate well after years of inactivity. Overall, it is likely that costs for replacing failed valves would be insignificant in comparison with costs of a CO_2 leak.

Several types of valves are available and in use, including flappers and ball valves. The flapper types seem to be more reliable, at least for oilfield applications (Garner *et al.*, 2002). EPA seeks comment on the merits of requiring down-hole shut-off valves in GS wells.

Corrosion Monitoring and Control: Existing UIC Class I deep well operating requirements allow Director's discretion to require corrosion monitoring and control in the case of corrosive fluids. Corrosion monitoring can help avoid or provide early warning of corrosion of well materials that could compromise the well's integrity. This is accomplished by exposing ''coupons,'' or small samples of the well material to the injection stream. The samples are periodically removed from the flow line, cleaned and weighed; the weight is compared to previous values to calculate a corrosion rate. Other methods of corrosion monitoring/control include: The use of wireline enhanced caliper or imaging logs to inspect the casing, the use of ultrasonic and electromagnetic techniques in well pipes (Brondel *et al.*, 1994), the use of cathodic protection (where the casing would become the cathode of an electrochemical cell), or the use of biocide/corrosion inhibitor fluid in the annular space between the casing and tubing.

CO_2 reacts with water to become acidic, potentially accelerating corrosion of well materials. The CO_2 stream for a GS project may also contain small volumes of impurities that could be corrosive. Thus, EPA is proposing to require corrosion monitoring for GS wells. Corrosion monitoring is further discussed in the monitoring and testing section of this preamble.

Injection Depth in Relation to USDWs: Today's proposal specifies a requirement that such injection should be allowed only beneath the lowermost formation containing a USDW. This is consistent with the siting and operational requirements for all Class I hazardous injection wells, and a very important protective component of the UIC program. Placing distance between the point of injection and USDWs allows for the necessary confining and buffer formations, and further provides for opportunity for additional monitoring to detect any excursions from the intended injection zone.

However, EPA is not prescribing a minimum injection depth to keep the CO_2 in a supercritical, liquid state after it is injected, as some well operators may choose to inject the CO_2 as a gas. If the trapping mechanism is sufficiently protective, the injected CO_2 should be contained regardless of its phase.

Some stakeholders and co-regulators have proposed other approaches for specifying an injection depth and these merit consideration by EPA. For example, one approach would be to require a minimum injection depth of approximately 800 m (2,625 feet) for GS of CO_2. The geothermal gradient and weight of the fluid and rock layers above this target depth would maintain CO_2 at a sufficiently high pressure to keep it in a supercritical, liquid state. Storing CO_2 at supercritical pressure would allow storage of greater volumes and thereby increase available underground storage capacity. Additionally, storing CO_2 in a supercritical, liquid state may prevent the frequency of well mechanical integrity failure. When supercritical CO_2 is injected into shallow formations where pressures are not high enough to maintain its supercritical state, it will revert to a gas. The expansion of gaseous CO_2 will cause a drop in temperature (the Joule-Thomson effect), and if this temperature drop is large enough, freezing and thermal shock may take place in the vicinity of the well. Thermal shock is a common cause of cracking in many types of pressure equipment, and repeated exposure to such stresses could compromise the integrity of the injection well's tubular components. Participants at the Technical Workshop on Well Construction and MIT suggested that these phase changes (i.e., supercritical liquid to gas) are potentially a greater mechanical integrity concern than corrosivity. Modeling by Oldenburg (2007) shows that if the pressure drop is not large (less than 10 bars), this effect will not be great enough to cause significant problems. However, technical workshop participants concluded that more research is needed on the effects of phase changes on well mechanical integrity.

EPA is aware that the proposed requirement of injecting CO_2 below the lowermost USDW may preclude injection into certain targeted geologic formations, which may be storage sites currently under consideration for GS. These formations may include unmineable coal seams (those not being used for Class II enhanced coal bed methane production), zones in between or above USDWs, and other formations also under consideration. In areas of the country with very deep USDWs, the need to construct GS wells beneath them may render GS technically impractical. As a result, the Agency is considering and requesting comment on alternative approaches that would allow injection between and/or above the lowermost USDW, and thus potentially allow for more areas to be available for GS while preventing USDW endangerment.

One alternative under consideration is a provision for Director's discretion to allow injection above or between USDWs in specific geologic settings where the depth of the USDWs may preclude GS, make GS technically challenging, or significantly limit CO_2 storage capacity. Such approval by the Director would allow injection between USDWs (and thereby allowing injection above the lowermost USDW) in circumstances in which it may be demonstrated that USDWs would not be endangered. An example where such injection may be appropriate presents itself in areas such as the Williston and Powder River Basins in Wyoming, North Dakota, and South Dakota, where receiving formations (formations with large CO_2 storage capacity) for GS have been identified above the lowermost USDW and where there may be thousands of feet of rock strata between the injection zone and the overlying and underlying USDWs. In these cases, injection above or between USDWs may be appropriate, however, the Agency currently lacks data to demonstrate that such practices are or are not protective of USDWs.

Also, EPA is considering allowing Directors to exempt all USDWs below the injection zone. Currently, Directors may issue ''aquifer exemptions'' which when approved, essentially determine that an aquifer is no longer afforded protection as a USDW, in accordance with the requirements of 40 CFR 144.7(b)(1). Aquifer exemptions are permitted 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 (please see specific aquifer exemption criteria at 40 CFR 146.4). When EPA exempts an aquifer, it is no longer considered a USDW now or in the future. EPA limits aquifer exemptions for injection operations to the circumstances where the necessary criteria at 40 CFR 146.4 are met and not, in general, for the purpose of creating additional capacity for the emplacement of fluids.

EPA carefully considers all aspects of ensuring the protection of USDWs before approving an aquifer exemption request for any injection purpose in UIC programs which it implements. The Agency's interpretation of the SDWA, and its own UIC regulations, currently allows for aquifer exemptions sought for specific reasons (as outlined above) and not solely for the purpose of relaxing well owner/operator requirements, such as operating, monitoring, or testing. Therefore, in general, the Agency does not consider aquifer exemption requests for non-injection formations. It has also been EPA's long-standing policy not to grant aquifer exemptions for the purpose of hazardous waste disposal because of the infeasibility of meeting Class I hazardous waste siting requirements (i.e., injection must be below the lowermost USDW).

However, aquifer exemptions could be issued for GS wells where receiving formations are situated above the lowermost USDW and where there are thousands of feet between the injection zone and the overlying and underlying USDWs. In these circumstances, the permit applicant would be required to meet all Class VI permit requirements.

It is also anticipated that some aquifers previously exempted for Class II injection operations may be appropriate formations for GS and permit applicants may seek to use these formations. In such circumstances, the permit applicant for a GS Class VI well would be required to seek a new aquifer exemption for the purpose of GS, and provide a non-endangerment demonstration that reflects the predicted extent of the CO_2 plume, the associated pressure front, and the scope of the injection activities.

Furthermore, there may be other geologic settings with formations that could receive and store CO_2 that are not below the lowermost USDW. Such formations include deep, marginal USDWs directly overlying crystalline basement rock and/or unmineable coal seams. Under today's proposal, these formations would not qualify for GS without aquifer exemptions. In these areas where USDWs directly overlie crystalline basement rock, permit applicants may seek aquifer exemptions and permits to inject CO_2 for GS into these exempted aquifers. In unmineable coal seams that are USDWs or contain or are bounded by formations that are USDWs, permit applicants may also seek aquifer exemptions and permits for GS.

In summary, EPA is soliciting comment on whether CO_2 injection should be allowed into an injection zone above the lowermost USDW, when the Director determines that geologic conditions (*e.g.*, thousands of feet of intervening formations between the injection zone and the overlying and/or underlying USDWs) exist that will prevent fluid movement into adjacent USDWs. EPA is also requesting comments on whether aquifer exemptions should be allowed for the purpose of Class VI injection, and under what conditions should such aquifer exemptions be approved. Finally, EPA seeks comment on whether the Agency should set a minimum injection depth requirement for CO_2 GS, rather than require that such injection take place below the lowermost USDW.

Tracers: While the UIC Program's protective elements greatly reduce the potential for leakage, leakage is a possibility in any underground injection project. Tracers may help facilitate leak detection. Though use of tracers is not required under existing deep well requirements, the buoyancy of CO_2 and the large volumes that are expected to be injected may warrant improved leak detection for GS wells. Detection of leakage of injected CO_2 at the surface would indicate potential endangerment to USDWs. Additionally, if tracers are used for CO_2 GS projects, they may also help owners or operators to infer geochemical processes caused by CO_2 (e.g., dissolution or precipitation of calcium carbonate) that may pose risks.

Gaseous CO_2 is odorless and invisible. Tracers can be odorants, such as those added to domestic natural gas, in order to serve as a warning of a natural gas leak. Mercaptans are the most effective odorants, however, they are not generally suitable for GS because they are degraded by oxygen, even at very low concentrations. The experience from the natural gas storage industry is that they are scrubbed from the gas by adsorption to the formation in the subsurface. Disulphides, thioethers and ring compounds containing sulfur are options for CO_2 GS odorants (IPCC, 2005). However, there has been no testing of these substances for GS, and it is unknown whether using them for GS would be effective.

Participants at the technical workshop on monitoring, measurement, and verification (MMV) discussed the use of tracers in monitoring. Measurement of stable isotopes of carbon (i.e., C12/C13 ratio) can serve as tracers and may be useful for identifying the source of CO_2 (e.g., anthropogenic or biological). Panelists also addressed the potential utility of perfluorocarbon (PFC) and other inert tracers in detecting CO_2 leakage. According to some researchers, PFCs are conservative and will remain with the CO_2. Unique suites (or batches) of PFCs can be created using different combinations of PFCs. Different PFC suites can be used to establish unique signatures for different time periods of prolonged injection or for multiple CO_2 injections, making it feasible to detect if a leak is transient versus long-term in nature.

There may be potential benefits of tracers for CO_2 GS operations, though tracers' effectiveness and cost-effectiveness are debated. There are also technical challenges, such as false positives, associated with their use that will vary on a case-by-case basis. In addition, in the case of PFCs, which have a global warming potential many orders of magnitude higher than CO_2, there may be concerns about the consequences of potential releases to the atmosphere. Today's proposal allows Directors' discretion on whether to require the use of tracers, and if so, what types of tracers. EPA seeks comment on the use of tracers in CO_2 GS operations, and any potential impact of tracers on human health or ecosystems as they relate to USDWs.

5. Proposed Mechanical Integrity Testing Requirements

Injection well mechanical integrity testing (MIT) is a critical component of the UIC Program's goal to protect USDWs. Testing and monitoring the integrity of an injection well, at the appropriate frequency, can verify that the injection activity is operating as intended and does not endanger USDWs. MIT requirements for GS wells should be tailored to address the unique properties of CO_2, specifically its buoyancy and potential corrosivity, so that owners or operators of GS projects will be able to detect defects within the well, and between the well and the borehole, before these defects could allow GS-related fluids to move into unintended formations or toward USDWs.

Currently, all UIC injection well owners or operators must demonstrate that their wells have both internal and external mechanical integrity (MI) (40 CFR 146.8). An injection well has internal MI if there is an absence of leakage in the injection tubing, casing, or packer. Typically, internal mechanical integrity testing is accomplished with a periodic pressure test of the annular space between the injection tubing and long string casing of this annual space. Usually, loss of internal MI is due to corrosion or mechanical failure of the injection well's components. Rarely, because of the multiple-barrier nature of injection well construction, do internal MI losses result in leakage outside of the well and present an endangerment to a USDW.

Injection well external integrity is demonstrated by establishing the absence of fluid flow along the outside of the casing, generally between the cement and the well structure, although such flow may also occur between the cement and the well bore itself. This is typically accomplished through the use of down-hole geophysical logs or surveys designed to detect such leaks, once every five years. 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 borehole. This type of failure can lead to movement of injected fluids out of intended injection zones and toward USDWs. As with internal MI failure, temporary loss of external MI rarely results in endangerment to USDWs.

Failure of either external or internal mechanical integrity may mean that one of the multiple protective layers in an injection well is not operating as intended. Proper testing can serve as an early warning to owners or operators that the well is not performing optimally and that maintenance or repair of a component of the well is needed before the injectate moves to unintended zones or a USDW is impacted.

The decades of State and EPA experience with Class I and Class II mechanical integrity testing requirements provides the best knowledge base for identifying appropriate MIT requirements for GS projects. This is supported by findings from technical workshops, conferences, and research. However, because of the buoyant and corrosive properties of a GS stream, current deep well internal and external MIT requirements will need to be tailored in order to ensure the protection of USDWs.

As previously discussed, internal MI testing is designed to evaluate the condition of internal well components. The evaluation is typically accomplished with an annual pressure test. However, due to the nature of the GS injection stream, corrosivity must be considered when planning for MITs in GS projects. Studies conducted by EPA of previous MIT results suggest that wells injecting corrosive fluids fail MITs at rates 2 to 3 times higher than those that inject non-corrosive fluids. Thus, a more corrosive injectate is a potential risk factor for MIT failure.

Therefore, today's proposal would require owners or operators of Class VI GS projects to monitor internal mechanical integrity of their injection wells by continuously monitoring injection pressure, flow rate, and injected volumes, as well as the annular pressure and fluid volume to assure that no anomalies occur that may indicate an internal leak. EPA requests comment on the practicability of this requirement.

Continuous internal mechanical integrity monitoring of GS project injection wells, instead of periodic testing (which is required for most other types of deep injection wells) is important because the corrosive nature of GS waste streams makes immediate identification of corrosion-related well integrity loss critical. Today's proposal would also require automatic down-hole shut-off mechanisms (see proposed injection well operating requirements section) in the event of an MI loss. Continuous computer-driven monitoring of internal MI would need to be performed in order for automatic shut-off systems to be activated. This combination of computer-driven continuous internal monitoring linked to an automatic down-hole injection shut-off provides the maximum protection to USDWs and the earliest warning to owners or operators that repairs need to be performed.

This proposed requirement would eliminate the necessity of conducting other periodic internal MITs. However, today's proposal would provide the Director with the discretion to request any other additional tests necessary to ensure the protection of USDWs.

As mentioned above, external mechanical integrity testing is used to determine the absence of fluid leaks behind the long string casing. Instead of requiring external MI to be demonstrated every five years (which is typical for other types of deep injection wells), today's proposal would require owners or operators of CO_2 wells to demonstrate injection well external mechanical integrity at least once annually. This increase in testing frequency (from once every five years to once a year) is justifiable for the protection of USDWs given the potential corrosive effects on injection well components (steel casing and cement) that are exposed to the GS stream and the buoyant nature of the injected fluid that tends to force it upward toward USDWs.

Today's proposal does not change the existing allowable methods for demonstrating external MI in deep injection wells. They would include the use of a tracer survey, a temperature or noise log, a casing inspection log if required by the Director, or an alternative approved by the Administrator and, subsequently, the Director. Today's proposal would also provide the Director with the discretion to request additional tests.

EPA proposes that owners or operators report semi-annually on the injection pressure, flow rate, temperature, volume and annular pressure, and on the results of MITs. This reporting frequency, which is the same as for other deep injection well classes, has proven to be timely for notification to permitting authorities on the status of the operation.

EPA seeks comment on the appropriate frequency of internal and external MITs for GS injection wells, the appropriate types of MITs, and how to optimize MIT methods for GS.

6. Proposed Plume and Pressure Front Monitoring Requirements

Monitoring associated with UIC injection wells is required to ensure that the injectate is safely confined in the intended subsurface geologic formations and USDWs are not endangered. Certain existing UIC program monitoring requirements apply to all wells, while others are based on site-specific information and Director's discretion. Information obtained through monitoring may be used to maintain the efficiency of the storage operation, minimize costs, and confirm that injection zone pressure decline follows predictions. Monitoring results of GS wells would also be used as data inputs for reevaluation of the site computational model and AoR and corrective action.

EPA considers CO_2 plume and associated pressure front monitoring to be necessary for verification of model predictions. An integrated monitoring and modeling strategy should be used to track the evolution of the CO_2 plume and associated pressure front. Monitoring may be conducted with a combination of direct and indirect techniques appropriate for the conditions of specific GS projects. Monitoring is necessary to verify initial model predictions given the uncertainty of CO_2 fate and transport; because large volumes of CO_2 will be injected during GS operations; and because of the challenges of comprehensive site characterization in large formations that may be used for GS projects. Monitoring results should be used to assess CO_2 movement through high-permeability regions (i.e., faults, fractures) not detected in site characterization and included in initial site modeling. Early pilot-projects have indicated that the most complete understanding of the site-specific behavior of CO_2 will result from monitoring the movement of CO_2 itself (e.g., Doughty *et al.*, 2007).

EPA seeks comment on the requirement for monitoring of GS sites for the purpose of tracking the location of the CO_2 plume and associated pressure front over time.

Testing and Monitoring Plan: A monitoring program for a GS project should be designed to detect changes in ground water quality and track the extent of the CO_2 plume and area of elevated pressure. Today, EPA is proposing that owners or operators of Class VI wells would submit, with their permit application, a testing and monitoring plan to verify that the GS project is operating as intended and is not endangering USDWs. This plan would be implemented upon Director approval and would include, at a minimum, analysis of the chemical and physical characteristics of the CO_2 stream; monitoring of injection pressure, rate, and volume; monitoring of annular pressure and fluid volume; corrosion monitoring; a demonstration of external mechanical integrity (see proposed mechanical integrity testing requirements section of the preamble); a 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, monitoring for CO_2 fluxes in surface air and soil gas, and any additional tests requested by the Director.

Monitoring within multiple layers (i.e., in the primary confining system; in USDWs and other shallow layers; and, at the surface) supports a multi-barrier approach to protecting USDWs. Surface air and/or soil gas monitoring may be used as the last line of monitoring to ensure that there has not been vertical CO_2 leakage, which could endanger USDWs. The program should also be site-specific, based on the identification and assessment of potential CO_2 leakage routes complemented by computational modeling of the site.

Under today's proposal, owners or operators would be required to analyze the CO_2 stream at a frequency sufficient to yield data representative of its chemical and physical characteristics. This analysis will provide information on the content and corrosivity of the injected stream, which in turn will support improvements in well construction and optimization of well operating parameters. EPA also proposes that owners or operators would monitor well materials for signs of corrosion, such as loss of mass, thickness, cracking, or pitting. The proposed requirements are critical to address the potential well integrity concerns associated with the corrosive nature of the CO_2 stream, to avoid (or provide early warning of) corrosion of well materials, and to protect the integrity of GS wells. Today's proposal would also require continuous monitoring of the injection pressure, rate and volume, as well as annular pressure and fluid volume discussed in the well construction and operation section of the preamble.

Monitoring CO_2 Movement and Reservoir Pressure: Monitoring subsurface geochemistry and the position of the CO_2 plume and pressure front are necessary to verify predictions of plume movement, provide inputs for modeling, identify needed corrective actions, and target geochemical and surface monitoring activities.

Under today's proposal, owners or operators would be required to track the subsurface extent of the CO_2 plume and pressure front using pressure gauges in the first formation overlying the confining zone or using indirect geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys) or other down-hole CO_2 detection tools, monitor for geochemical changes in subsurface formations, and if directed, monitor at the surface. Today's proposal would also require owners or operators to monitor ground water quality and geochemical changes above the confining system. The results of this monitoring would be compared to baseline geochemical data to identify changes that may indicate unacceptable movement of CO_2 or formation fluids.

In order to provide guidance related to monitoring of GS sites, EPA invited expert advice and reviewed technical documentation. EPA held a technical workshop on measurement, monitoring, and verification focused on the availability and utility of various subsurface and near-surface monitoring techniques that may be applicable to GS projects. This workshop, co-sponsored by the Ground Water Protection Council (GWPC), took place in New Orleans, LA, on January 16, 2008.

Monitoring within the confining zone for pressure, pH, salinity, or the presence of dissolved minerals, heavy metals, or organic contaminants requires direct access to the subsurface via monitoring wells. Wells installed for this purpose would be strategically placed in areas predicted to overlie the eventual CO_2 plume and area of elevated pressure. Well number and placement would be based on project specific information such as injection rate and volume, site specific geology, baseline geochemical data, and the presence of artificial penetrations. Predictive models of the extent and direction of plume movement can support decisions about monitoring well placement. This has the dual benefit of targeting resources associated with what is an expensive monitoring activity and minimizing the number of artificial penetrations near the injection well, which could potentially become conduits for fluid movement into USDWs.

Today's proposal would require that owners or operators perform a pressure fall-off test at least once every five years. Pressure fall-off tests are designed to ensure that reservoir injection pressures are tracking to predicted pressures and modeling input. They may be used in project siting and AoR calculations. Results of pressure fall-off tests may indicate mischaracterization of the site specific geology and potentially unidentified leakage pathways. EPA seeks comment on the use and frequency of pressure fall-off testing for GS wells.

Pressure monitoring, both at the surface and in the formation, is a routine part of CO_2 injection projects that serves several purposes. For instance, monitoring pressure in injection wells allows for use of shut-off valves in the event that injection pressure exceeds the formation fracture pressure, or pressure drop-offs indicate a subsurface leak (IPCC, 2005). Pressure monitoring in monitoring wells provides an indication of whether there is potential for brine intrusion into USDWs and CO_2 leakage. When combined with information on temperature, pressure data provide an indication of the phase (e.g., gas, supercritical) and amount of the injected CO_2.

Various pressure sensors are available, and monitoring can be conducted continuously. Conventional sensor types include piezo-electric transducers, strain gauges, diaphragms, and capacitance gauges (Burton *et al.*, 2007). Fiber optic pressure and temperature sensors are also now commercially available and can be installed down-hole and connected to the surface through fiber optic cables. According to Burton *et al.* (2007), current monitoring technologies are more than adequate for monitoring pressure in a GS project.

Direct geochemical monitoring is an important part of a monitoring program. Temperature, salinity, and pH should be monitored, as these parameters provide basic information for understanding water and gas geochemistry. Additionally, obtaining ground water samples via monitoring wells allows direct measurement of aqueous and pure-phase CO_2. By studying the interactions between brine and CO_2, it can be determined whether precipitation and/or dissolution of minerals is occurring (Nicot and Hovorka, 2008). These analyses will also indicate the rate of CO_2 trapping mechanisms, and whether mineral dissolution may be causing permeability changes in the formation or impacting USDWs. Geochemical monitoring may also be conducted for heavy metals and organic contaminants that may potentially be mobilized in the formation due to injection.

Information and discussions from EPA technical and public workshops indicate that the collection of adequate baseline (pre-injection) data is critical for planning monitoring and for detecting CO_2 movement and leakage during and after injection.

While the use of tracers is not a specific monitoring requirement in today's proposal (per III.A.4), some Directors may require owners or operators to use them. EPA has considered the merits of tracers for CO_2 monitoring and recognizes that they may also be voluntarily employed by owners or operators. Tracers can also be measured through direct geochemical sampling to indicate the speed and direction of movement of CO_2 after injection. Naturally occurring tracers include stable isotopes (atoms of a particular element with different numbers of neutrons) of carbon and oxygen. Analyses of the amounts of carbon-13 and oxygen-18 isotopes in water are commonly used to track movement through the environment and to elucidate geochemical processes. It is also possible to include tracers, such as perfluorocarbons or noble gases, with the injected CO_2 (Nimz and Hudson, 2005). Loss of tracers between the injection well and monitoring well may indicate diffusion into low-permeability materials, sorption, partitioning into non-aqueous phase liquids, partitioning into trapped gas phases, or leakage of CO_2 (Nicot and Hovorka, 2008). Tracers were more fully discussed in the well construction and operation section of the preamble.

There are several technical challenges associated with in-situ monitoring of formation fluids via wells. In the course of sample retrieval, there will be pressure changes, causing changes in CO_2 solubility and pH. To address this, LBNL developed a ''U-tube'' sampling apparatus to enable collection of fluid and gas samples at in-situ pressure conditions. Also, samples collected from monitoring wells are point measurements that may not fully represent the entire reservoir, especially if there are extensive physical heterogeneities.

Geophysical Methods for Plume Tracking: Various non-invasive deep subsurface monitoring techniques are available to track the movement of the CO_2 plume. Many of these methods have been developed for use in the oil and gas industry, and some may also support certain aspects of baseline geologic characterization. Seismic and electrical techniques have been used to gather data related to rock composition, porosity, fluid content, and in-situ stress state.

In seismic surveying, a controlled source of seismic energy is used to send vibrations through the ground. The time it takes for the seismic waves to reflect off of a subsurface feature and reach a receiver at the surface provides information about the depth of the feature. By using an array of receivers, possible plume and leakage flowpaths may be discerned. Seismic surveys may also be useful for monitoring how rock properties change with time during injection and for mapping of the CO_2 plume. This method has been used to study the subsurface in the area near the injection well for the CO_2-SINK project in Germany (Juhlin *et al.*, 2006) and at the Sleipner and In Salah sites. Seismic studies can also be done in a crosswell arrangement by placing an array of receivers in one borehole and drawing a seismic source upwards in another borehole, firing at periodic intervals. Current crosswell experience relevant to CO_2 sequestration includes successful imaging of CO_2 saturation and pressure effects in a carbonate reservoir in West Texas (Harris and Langan, 2001). Vertical seismic profiling (VSP), conducted by placing geophones in a vertical array inside a borehole and measuring sound sources originating at the surface, is another promising technology for plume detection and monitoring.

Electrical methods rely on the electrical properties of the medium being studied and offer promise for CO_2 plume monitoring. Electromagnetic (EM) surveys induce a current in subsurface materials, and conductivity meters detect areas with increased conductivity. Near the surface, EM can detect buried metal objects and contaminated soils. In the deeper subsurface, EM surveys can be used to detect certain contaminant plumes. EM surveys can also be done in crosswell fashion. At Lawrence Livermore National Laboratory, researchers are conducting a long-term study using time-lapse multiple frequency EM survey characterization to image CO_2 injected as part of an EOR operation (Kirkendall and Roberts, 2001).

Electrical resistance tomography (ERT) measures electrical resistance by means of electrodes that may be placed at the surface, but are more commonly arrayed down boreholes in a crosswell configuration. Because the electrical properties of a medium are sensitive to fluid chemistry, ERT can be used for monitoring fluid migration in the subsurface. The oil industry has used ERT, and it has been also used for environmental applications such as detection of contaminant plumes at waste sites. Newmark (2003) reported preliminary data on the use of crosswell ERT at an EOR site to monitor for CO_2.

Microgravity surveys detect density variations in the subsurface using sensitive gravity measurements made at the (ground) surface. Microgravity surveys have been used to characterize subsurface formations, and given the density differences between CO_2 and formation brines, may be useful for tracking a CO_2 plume. Nooner *et al.* (2003) discuss use of microgravity surveys at the Sleipner CO_2 GS project in Norway.

GEO–SEQ (2004) discusses the capabilities of seismic and electrical crosswell methods for CO_2 GS. The authors note the high spatial resolution of these methods and state that they can image leaks and fluid saturation within a reservoir. Simulations discussed in the manual confirm that seismic and electrical conductivity crosswell methods could provide information on the saturation of CO_2 within the reservoir between wells. The authors note that seismic crosswell methods could also be used to detect CO_2 phase changes. Although these methods are costly and time consuming, they may prove useful at GS sites in the future. To fully implement these technologies, additional research is needed regarding the electrical and seismic properties of subsurface media containing CO_2.

Some stakeholders expressed concerns about the usefulness of seismic surveys as a CO_2 tracking tool under certain geologic conditions, particularly given the cost of specific technologies. Based on information evaluated to date, EPA believes that tracking the plume and pressure front is an important companion step to address any uncertainties associated with initial AoR modeling and requests comment on this approach and more efficient alternatives that may be used to track the plume and pressure front.

As such, allowing flexibility in choosing the plume tracking methods and other monitoring technologies may provide an appropriate balance between the protective nature of indirect monitoring and cost considerations, as well as allowing for the adoption of continuously advancing technology.

Surface Air and Soil Gas Monitoring: Surface air measurements can be used to monitor the flux of CO_2 out of the deep subsurface, with deviations from background levels representing potential leakage. If deviation in the flux of CO_2 is detected, it may indicate potential endangerment of USDWs. While subsurface monitoring forms the primary basis for protecting USDWs, near-surface and surface techniques could be the last line of monitoring. Under today's proposal, owners or operators could, at the Director's discretion, be required to conduct surface air monitoring and/or soil gas monitoring in the AoR. Knowledge of leaks to shallow USDWs is of critical importance since 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 can identify the general location of the leak.

A range of techniques employed at varied monitoring frequencies are available for implementation. Optimal spacing of monitoring wells, eddy covariance towers, or soil gas chambers would need to be selected, and may be based on the outcome of other monitoring techniques such as seismic or Electrical Resistance Tomography (ERT).

For surface air monitoring, chambers can be placed directly on the soil and trapped gases are passed through an infrared gas analyzer to determine CO_2 content (GEO–SEQ, 2004). Changes in CO_2 concentration and air flow rates are used to calculate a flux. Measurements using chambers are typically conducted along a grid, which has the benefit of defining spatial and temporal variations in CO_2 flux that could be used for pinpointing and quantifying any leaks. Chamber measurements, however, are labor-intensive and are not efficient for sampling over large areas. For each of these methods, baseline (pre-injection) monitoring is very important in order to establish conditions for future comparison. There are natural sources of CO_2 that can have wide variability and thus could mask leakage from a GS operation.

Eddy covariance techniques have been used for ecological applications to measure carbon fluxes from vegetated areas, and show promise for CO_2 monitoring for GS operations (Miles *et al.*, 2005). The equipment is installed on a tower and CO_2 is measured with an infrared gas analyzer (GEO–SEQ, 2004). Wind velocity, relative humidity, and temperature are also measured and the information is integrated to calculate a CO_2 flux. The height of the tower controls the aerial coverage, with higher towers averaging over larger areas. Because of the large coverage, the exact location of a leak would be difficult to pinpoint, and this method may be better for detecting slow, diffuse leaks. Eddy covariance also assumes a horizontal and homogeneous land surface, which may not hold true for all GS locations. It does have the advantage of being automated, greatly reducing the labor involved.

Hyperspectral image analysis is a form of remote sensing that has been used, among other applications, for mapping vegetation habitat boundaries and for differentiating species types. Scanners collect images of a given feature using a number of relatively small wavelength bands, including the visible and infrared portions of the spectrum. Because different elements have different spectral signatures, a hyperspectral image can convey information about composition. The potential utility for CO_2 monitoring would be the ability to map the response of vegetation to elevated soil CO_2 concentrations (Pickles and Cover, 2005).

LIDAR (light detection and ranging) is a remote sensing method that is used extensively in atmospheric science, and is currently under investigation as an option for CO_2 detection to monitor GS sites (Benson and Myer, 2002). Similar in principle to RADAR, LIDAR uses light instead of radio waves, permitting resolution of very small features, such as aerosols. Light is pulsed from a laser and various constituents in the atmosphere reflect back some of the light. A number of properties of the backscattered light allow one to infer the atmospheric composition, including concentrations of CO_2. Currently, differential absorption LIDAR (DIAL) is being studied by researchers at Montana State University for detecting CO_2 leaks in pipelines.

EPA proposes that owners and operators report semi-annually on the characteristics of injection fluids, injection pressure, flow rate, temperature, volume and annular pressure, and on the results of MITs, ground water monitoring, and any required atmospheric/soil gas monitoring.

EPA seeks comment on the appropriate amount and types of monitoring that should be conducted at a GS site. Specifically, EPA seeks comment regarding the usefulness of indirect geophysical monitoring and surface air and soil gas monitoring. In addition, EPA seeks comment regarding the use of a Director-approved monitoring plan for GS sites.

7. Proposed Recordkeeping and Reporting Requirements

Submissions Required for Consideration of Permit Applications: Today's proposal would require that owners and operators submit relevant site information to the permitting authority for consideration of permit applications. This information includes maps of the injection wells, the AoR as determined through computational modeling, all artificial penetrations within the AoR, maps of the general vertical and lateral limits of USDWs, maps of the geologic cross sections of the local area, the proposed operating data and injection procedures, proposed formation testing program, and stimulation program, well schematics and construction procedures, and contingency plans for shut-ins or well failures. EPA is also proposing that permit applicants submit a demonstration of financial responsibility to plug the well, to provide for post-injection site care, and site closure.

EPA is proposing today that permit applications for GS sites include several plans not currently required under existing UIC regulations. These plans include a monitoring and testing plan, an AoR and corrective action plan, and a post-injection site care and site closure plan. The requirement for additional plans is intended to provide the Director the opportunity to assess proposed project operating procedures, and addresses GS requirements that are seen to be site-specific (e.g., what monitoring techniques will be used). In addition, these plans are intended to establish an ongoing dialogue between the operator and the permitting authority which is more substantial than that required for other classes of injection wells. EPA seeks comment on the merits of requiring plans for monitoring, AoR, and post-injection site care as part of a permit application.

Operational Recordkeeping and Reporting Requirements: Under current UIC requirements, operators must report on a regular basis to the permitting authority, the physical and chemical characteristics of the injected fluids, as well as other operational data. For Class I industrial and Class I hazardous waste wells and Class III wells, operators must submit this information on a quarterly basis. For Class II wells, operators must submit this information on an annual basis. Today's proposal would require that owners or operators of Class VI wells report semi-annually to the permitting authority, on the physical and chemical characteristics of injection fluids, injection pressure, flow rate, temperature, volume and annular pressure, annulus fluid volume added, and the results of MITs, plume tracking, and atmospheric/soil gas monitoring. Additionally, owners and operators will be required to submit the results of AoR modeling revisions; any updates to the information on the type, number, and location of all wells within the site AoR; and information on additional corrective action performed or planned based on AoR reevaluations. EPA considers a less frequent reporting requirement for Class VI wells compared to Class I wells appropriate considering the ongoing dialogue for Class VI wells established by multiple plans as discussed above.

Under today's proposal, owners and operators would also be required to maintain recordkeeping and reporting information for the duration of the project, as well as three years after site closure (following the post-injection site care period); and to keep their most recent plugging and abandonment report for one year following site closure.

Reporting Associated with Well Plugging, Post-injection Site Care, and Site Closure: EPA proposes that owners or operators notify the Director at least 60 days prior, or at a Director-determined time, of their intent to plug the well and of any updates to the post-injection site care and site closure plan. After the well is plugged, owners and operators would submit a well plugging report stating that the well was plugged in accordance with the approved post-injection site care and site closure plan or specify the differences between the plan and the actual well plugging. During the post-injection site care (monitoring) period, owners or operators would report periodically on the results of monitoring. At the end of the post-injection site care period, owners or operators would submit a site closure report, along with a non-endangerment demonstration showing that conditions within the subsurface indicate that no additional monitoring is necessary to assure that there is no endangerment to USDWs associated with the injection.

EPA seeks comment on the frequency of all proposed reporting requirements.

Electronic Reporting and Recordkeeping: Under today's proposal, EPA would require owners or operators to report data specified in section 146.91 in an electronic format acceptable to the Director for site, facility, and monitoring information. At the discretion of the Director, formats other than electronic may be accepted after a determination has been made that the entity does not have the capability to use the required format. Long-term retention of records in an electronic format may also be required at the Director's discretion. If records are stored in an electronic format, information should be maintained digitally in multiple locations (i.e., backed-up) in accordance with best practices for electronic data.

EPA has previously required electronic reporting of monitoring data in the program implemented under the Unregulated Contaminant Monitoring Rule (64 FR 50611, September 17, 1999, 40 CFR 141.35(e)). EPA believes that the permit applicants will have the resources to provide electronic data to the permit authority and that electronic reporting will reduce future burden related to recordkeeping. In addition, electronic data submissions will facilitate the application review process and make it easier to track progress of GS projects. EPA is committed to providing resources to States to develop the capability to exchange data electronically. Several States have received grants to develop electronic data exchange capability for their current UIC programs.

EPA seeks comment on the requirement for electronic reporting in today's proposed rule. In addition to the above recordkeeping and reporting requirements, EPA considered a requirement for owners or operators of GS sites to provide an annual report during the lifetime of the project, including the post-injection period, regarding the GS operation. This report would describe the status of the operation, any new data about the site including operational and monitoring data, new GS operations, or other activities that may affect the plume movement, any non-compliance, and knowledge gained on GS technology that could contribute to the state of the science on GS. This requirement would address the unique and large-scale nature of CO_2 GS operations, provide the public with information regarding the operation, and facilitate information transfer about GS technology. Although EPA has not included a requirement for this report in today's proposal, EPA seeks comment regarding the necessity for such an annual report.

8. Proposed Well Plugging, Post-Injection Site Care, and Site Closure Requirements

Today's proposal outlines well plugging and post injection site care requirements for CO_2 injection sites after injection activities end. If finalized, these new requirements at 40 CFR 146.92–146.93 would ensure that owners or operators plug wells and manage sites in a manner so that wells do not serve as a conduit for escape of stored CO_2 through unexpected migration from the injection site after injection ends, preventing endangerment of USDWs. EPA is proposing to give owners or operators flexibility in meeting the well plugging requirements by allowing the owner or operator to choose from available materials and tests to carry out the proposed requirements. EPA is not specifying the types of materials or tests that must be used during well plugging because there are a variety of methods that are appropriate and new materials and tests may become available in the future. EPA is also proposing that a combination of a fixed timeframe and performance standard be used to determine the duration of the post-injection site care period.

Steps in Injection Well Plugging: EPA is proposing that owners or operators develop a well plugging plan, and conduct several activities associated with the plugging of GS wells. Injection well plugging must comply with requirements of 40 CFR 144.12(a). The plan includes: (1) Providing notice of intent to plug a well at least 60 days prior to well plugging, (2) flushing each well to be plugged with a buffer fluid, (3) testing the mechanical integrity of each well, (4) plugging each well in a manner that will prevent the movement of fluid that may endanger USDWs, and (5) submitting a plugging report within 60 days after plugging the well or at the time of the next semi-annual report (whichever is less).

Notice of intent to plug: The notice of intent to plug provides a 60-day advance notice to the Director that the owner or operator intends to close the well. If circumstances warrant a shorter time period for giving notice of intent to plug, the Director may approve a shorter notice period.

Well Flushing: Flushing removes fluids remaining in the long string casing that could react with the well components over time. Fluids used for flushing may vary, but must provide sufficient buffering ability to avoid the possibility of reactions due to residual CO_2 or other contaminants in the fluid.

Mechanical Integrity Testing: Mechanical integrity testing allows owners or operators to ensure that the long string casing and cement that are left in the ground after well plugging and site closure maintain integrity over time. For GS wells, there are a number of methods that can be used to test mechanical integrity, including pressure tests with liquid or gas, radioactive tracer surveys, and noise, temperature, pipe evaluation, or cement bond logs.

Well Plugging: The Agency is proposing that owners or operators plug wells in a manner that does not endanger USDWs. This may be accomplished in a number of ways using a number of different types of materials. In the case of GS wells, the plugging materials must be compatible with the fluids with which the materials may be expected to come into contact and plugged to prevent the movement of fluids either into or between USDWs.

Plugging Report: The owner or operator would be required to submit a report which includes information on the implementation of the plugging plan, including the date the well was plugged, the activities conducted to prepare the well for plugging, the materials used for plugging, and the location of the well. The owner or operator may either submit the plugging report as a separate report within 60 days after the plugging activity, or update the semi-annual report required at 40 CFR 146.92 of this proposed rule to include plugging information and submit the updated report within 60 days after the plugging activity. EPA is proposing that the owner or operator must certify that the plugging report is accurate. If the well was plugged by an entity other than the owner or operator, that entity must also certify that the plugging report is accurate.

In addition, EPA is proposing the owners or operators prepare for eventual site closure in advance of the time when well plugging activities take place to ensure that a plan is in place in the event of an unexpected need to plug a well or close the site. Today's proposal would require owners or operators to submit a well plugging plan at the same time the permit application is submitted and to have this plan approved by the Director. As part of the well plugging plan, the owner/operator would be required to conduct certain activities related to well plugging, and provide the information related to well plugging, including the following: (1) Testing methods used to determine that the components of the well will maintain mechanical integrity over time; (2) type and number of plugs to be used; (3) placement of each plug, including the elevation of the top and bottom of each plug; (4) type, grade, and quantity of material to be used in plugging; and (5) method used to put plugs in place. In addition, if for any reason the well plugging activities stated in the plan no longer reflect what is likely to occur upon plugging of the well, the owner or operator would be required to make changes to the plan and submit to the Director for approval before notifying the Director of intent to plug the well.

Post-Injection Site Care: Today's proposal would also require that owners or operators (1) develop a post-injection site care and closure plan, (2) monitor the site following cessation of the injection activity, and (3) plug all monitoring wells in a manner which prevents movement of injection or formation fluids that could endanger a USDW.

The post-injection site care and site closure plan would be required to be submitted as part of the permit application and approved by the Director. It describes several activities associated with the post-injection site care and site closure of GS sites. Activities that would be required in the post-injection site care and site closure plan include: (1) Record of the pressure differential between pre-injection and anticipated post-injection pressures in the injection zone; (2) predicted position of the plume and associated pressure front at the time the site is closed; (3) description of post-injection monitoring location(s), methods, and proposed frequency of monitoring; and (4) schedule for submitting post-injection site care and monitoring results to the Director. In addition, if for any reason the post-injection site care and site closure activities stated in the plan no longer reflect what is likely to occur upon closing the site, the owner or operator would be required to make changes to the plan and submit the plan to the Director for approval within 30 days of such change. Examples of factors which may require a modified post-injection site care and site closure plan would include changes in injection procedures or volumes or plume movement in an unanticipated direction.

Upon permanent cessation of injection, the owner or operator would either submit an amended post-injection site care and site closure or demonstrate to the Director through monitoring and modeling results that no amendment to the plan is needed. Owners or operators would also be required to use any other information deemed necessary by the Director to make this demonstration.

The post-injection site care and site closure plan would include a description of the monitoring that will occur after injection ceases. The owner or operator would monitor the site to show the position of the CO_2 plume and pressure front and demonstrate that USDWs are not being endangered. A record of the pressures in the injection formation and surrounding areas as well as the pressure decay rate can help the owner or operator determine that the injected fluid does not pose endangerment to USDWs.

Post-Injection Site Care Timeframe: Current UIC regulations do not limit the duration of the post-injection site care period; however, many environmental programs use a 30-year period as a frame of reference. In many cases, a 30-year timeframe has been sufficient to determine that remaining pressure in plugged wells containing liquids will not lift fluid to overlying strata (53 FR 28143, July 26, 1988). However, characterizing post-injection site care timeframes for GS is more challenging. Given the buoyancy of CO_2, viscosity, and large injection volumes associated with GS, the area over which CO_2 will spread in the subsurface is likely to be larger than for existing well classes and therefore, the area over which there is potential for endangerment of USDWs is likely to be greater. The presence of physical and geochemical trapping mechanisms is likely to reduce the mobility of CO_2 over time and research also suggests that pressure within the storage system will drop significantly when injection ceases, thus decreasing the risks of induced seismic activity, and faulting and fracturing and making storage more secure over longer timeframes. However, the timeframe over which this happens is difficult to define because it is based on site-specific considerations.

EPA considered three distinct alternatives for determining post-injection site care and monitoring timeframes (1) establishing a fixed timeframe for post-injection site care; (2) allowing a performance-based approach to the post-injection site care time period; and (3) a combination of fixed timeframe and performance standard.

EPA considered the approach of specifying a fixed duration of time after which the post-injection site care ends. As part of this approach, EPA evaluated four different timeframes: 10, 30, 50, and 100 years.

EPA reviewed studies, industry reports and environmental programs to determine appropriate post-injection site care timeframes. Studies reviewed included those done by: Flett M., Gurton R., and G. Weir. 2007; Obi E.I., and M.J. Blunt. 2006; and Doughty, C. 2007 (see USEPA, 2008d). A review of these studies suggests that the actual time for CO_2 plume stabilization (i.e., slowing down or cessation of plume movement, and/or immobilization of most of the CO_2 mass through various trapping mechanisms) will be very site specific, being influenced by geologic factors such as formation permeability, geochemistry, and the degree of capillary trapping. In addition, predicted results will depend on several modeling considerations and assumptions, and thus will be to some degree model specific. Based on a review of the three studies used for this preliminary analysis, modeling results indicate that the CO_2 plume stabilized on the time frame of 10–100 years after the cessation of injection (USEPA, 2008d).

EPA also reviewed an IOGCC Task Force report which suggests a 10-year time frame for the post-injection site care period which commences when injection ceases until the release of the operator from liability. Alternatively, some environmental programs—including the UIC Program—use a 30-year period as a frame of reference.

While 10 years may be within the timeframe suggested in some studies, there are circumstances under which the potential risks of endangering USDWs will not decline within that timeframe given that stabilization may continue for several decades (USEPA, 2008d). Also, a 30-year timeframe can be appropriate for the types of fluids typically injected under the UIC Program (i.e., fluids that are liquids at standard pressure and temperature). Longer timeframes may be more appropriate for GS wells, because the fluid is likely to be stored in a supercritical phase, the plume for a full-scale GS project will likely be large, and substantial pressure increases will likely be observed during operation. However, once injection ceases, pressure will likely begin to dissipate and 30 years may be enough time for the plume and pressure front to stabilize.

Another option considered by the Agency is to apply a performance standard, i.e., that post-injection site care will continue until the plume is stabilized and cannot endanger USDWs. Current UIC regulations at 40 CFR 146.71 utilize a performance type approach by requiring that the owner or operator of a Class I hazardous well observe and record pressure decay for a time specified by the Director. A similar performance standard could be considered for GS wells. Pressure decay data help to define the appropriate period of regulatory concern, because the likelihood that the injected fluid will migrate into USDWs above or adjacent to the injection zone decreases as injection-induced pressures in the formation decay. The post-injection site care period ends when the models predicting CO_2 movement are consistent with monitoring results demonstrating that there is no potential threat of endangerment to USDWs.

Combination of Fixed Timeframe and Performance Standard: EPA is proposing using a combination of fixed timeframe and a performance standard as described above. EPA is tentatively proposing a post-injection site care (monitoring) period of 50 years with Director's discretion to change that period to lengthen or shorten the 50-year period if appropriate. The default timeframe could be lengthened by the Director if potential for endangerment to USDWs still exists after 50 years or if modeling and monitoring results demonstrate that the plume and pressure front have not stabilized in this period. Conversely, the Director could reduce the 50-year time period if data on pressure, fluid movement, mineralization, and/or dissolution reactions support a determination that movement of the plume and pressure front have ceased and the injectate does not pose a risk to USDWs. EPA requests comment on the proposed use of a tentative 50-year fixed timeframe that could be modified at the Director's discretion based on monitoring and modeling data.

To ensure that the post-injection site care monitoring timeframe is long enough to determine that there is no threat of endangerment to USDWs from injection activities, EPA is proposing a default post-injection site care period of 50 years. During this 50-year period, the owner or operator would be required to submit periodic reports providing monitoring results and updated modeling results as appropriate until a demonstration of non-endangerment to USDWs can be made. Once the owners or operators provide documentation that demonstrates that the models predicting CO_2 movement are consistent with monitoring results and that there are no longer risks of endangerment to USDWs, they could request that the Director authorize site closure.

EPA is also proposing to allow the Director to shorten or lengthen the 50-year timeframe based on performance of the site. The Director may require that the post-injection site care period extend beyond the 50-year time frame if a demonstration of non-endangerment to USDWs cannot be made. Alternately, if the owner or operator can demonstrate that the remaining pressure front and plume will not endanger USDWs, then owners or operators may request a decreased post-injection site care period.

While EPA considered the 10-year, 30-year, and 100-year timeframes, the Agency is proposing a 50-year timeframe because there are circumstances under which the potential risks of endangerment to USDWs will not decline within 10 years. Furthermore, the time needed to allow pressures to equalize within the subsurface because of the higher levels of mobility of injected CO_2 may exceed 30 years, and EPA wishes to emphasize that site closure cannot occur until monitoring and modeling data establish to the Director's satisfaction that potential risks of endangerment to USDWs have ceased. EPA is not proposing 100 years as the default because EPA believes that in general plume stabilization will occur before this time. However post-injection site care requirements could be extended for 100 years (or longer) if monitoring and modeling information suggest that the plume may still endanger USDWs throughout this period. EPA considers that a 50-year timeframe represents a reasonable mid-point for the default time frame, which may be modified with the approval of the Director based on a demonstration (by the owner or operator) using monitoring and modeling, that the injected CO_2 will not endanger USDWs.

Site Closure: The Director would determine that the post-injection site care period has ended and authorize site closure when the following have occurred:

- The Director receives all information required of the post-injection site care and site closure plan;
- The data demonstrate to the satisfaction of the Director that there is no threat of endangerment to USDWs.

Once the Director approves site closure, the owner or operator is required to submit a site closure report within 90 days. The report would 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 carbon dioxide stream. The purpose of this report would be to provide information to potential users and authorities of the land surface and subsurface pore space regarding the operation. In addition, the owner or operator of the injection site 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 notification to any potential purchaser of the property information that the land has been used to sequester CO_2.

EPA is requesting comments on the proposed requirements for well plugging, post-injection site care, and site closure, including the proposed requirements for the post-injection time period. In addition, EPA seeks comment on whether the Director should be allowed to shorten the timeframe based on performance information, and whether EPA should require a shorter or longer post-injection period if data suggests the time frame should be adjusted.

9. Proposed Financial Responsibility and Long-Term Care Requirements

Today's proposal would require that owners or operators demonstrate and maintain financial responsibility, and have the resources for activities related to closing and remediating GS sites. EPA is proposing that the rule only specify a general duty to obtain financial responsibility acceptable to the Director, and will provide guidance to be developed at a later date that describes recommended types of financial mechanisms that owners or operators can use to meet this requirement.

Although the SDWA does not have explicit provisions for financial responsibility, as included in RCRA, EPA believes that the general authorities provided under the SDWA authority to prevent endangerment of USDWs include the authority to set standards for financial responsibility to prevent endangerment of USDWs from improper plugging, remediation, and management of wells after site closure. The SDWA authority does not extend to financial responsibility for activities unrelated to protection of USDWs (e.g., coverage of risks to air, ecosystems, or public health unrelated to USDW endangerment). It also does not cover transfer of owner or operator financial responsibility to other entities, or creation of a third party financial mechanism where EPA is the trustee.

Today's proposal would require owners or operators to demonstrate financial responsibility for corrective action described in 40 CFR 146.84 of this notice, including injection well plugging, post-injection site care and site closure, and emergency and remedial response using a financial mechanism acceptable to the Director. The Director would determine whether the mechanism the owner or operator submits is adequate to pay for well plugging, post-injection site care, site closure, and remediation that may be needed to prevent endangerment of underground sources of drinking water.

Owners or operators would no longer need to demonstrate that they have financial assurance after the post-injection site care period has ended. This generally occurs when the Director approves the completed post-injection site care and site closure plan and then determines that the injected fluid no longer poses a threat of endangerment to USDWs (e.g., the fluid no longer exhibits a propensity to move or migrate out of the injection zone to any point where it could endanger a USDW).

The Agency is proposing that the owner or operator periodically update the cost estimate for well plugging, post-injection site care and site closure, and remediation to account for any amendments to the area of review and corrective action plan (40 CFR 146.84), the plugging and abandonment plan, and the post-injection site care and site closure plan (40 CFR 146.93). EPA is also proposing that the owner or operator submit an adjusted cost estimate to the Director if the original demonstration is no longer adequate to cover the cost of the injection well plugging, post-injection site care, and site closure. As proposed, the Director would set the frequency for owner or operator re-demonstration of financial responsibility and resources. It may be appropriate to re-demonstrate financial responsibility on a periodic basis. Such re-demonstration would take into account any amendments to the area of review and corrective action plan (40 CFR 146.84) and adjustments for inflation. It may also be necessary to adjust cost estimates if the Director has reason to believe that the original demonstration is no longer adequate to cover the cost of the well plugging and post-injection site care and site closure. EPA is also proposing that the owner or operator notify the Director of adverse financial conditions, including but not limited to bankruptcy proceedings, which name the owner or operator as debtor, within 10 business days after the commencement of the proceeding.

EPA plans to develop guidance that is similar to current UIC financial responsibility guidance for Class II owners or operators. Currently, EPA guidance (USEPA, 1990) describes several options owners or operators can use to meet the requirements to demonstrate financial responsibility for well plugging. Financial assurance is typically demonstrated through two broad categories of financial instruments: (1) Third party instruments, including surety bond, financial guarantee bond or performance bond, letters of credit (the above third party instruments must also establish a trust fund), and an irrevocable trust fund; (2) self-insurance instruments, including the corporate financial test and the corporate guarantee.

Supplemental Information: In recent years, the EPA's Office of the Inspector General (OIG) and the U.S. Government Accountability Office (GAO) have raised issues regarding the use of financial responsibility instruments applicable to site closure for several EPA programs. Information regarding these reviews and EPA's responses are available at *http://www.gao.gov/new.items/d03761.pdf; http://www.epa.gov/oig/reports/2001/finalreport330.pdf; http://www.epa.gov/oig/reports/2005/20050926-2005-P-00026.pdf.* The OIG and GAO recommendations suggest that EPA may need to update or provide additional guidance in the following areas: Cost estimation methodology; pay-in period for trust funds; the type of insurance provider that may be used; requirements for acceptable surety bonds and/or their providers; and the way by which corporations demonstrate financial strength/credit worthiness.

In response to evaluations of financial responsibility instruments, EPA's RCRA program has issued a comprehensive financial responsibility strategy to improve the implementation of the financial responsibility requirements, as well as assess whether regulatory changes to certain mechanisms and financial responsibility requirements are warranted. EPA has begun implementing this strategy by providing additional guidance to support implementation and oversight of RCRA financial responsibility programs, providing training to EPA Regions and states, and developing tools (e.g., cost-estimating software) to assist staff in performing reviews of complex cost information.

In addition, EPA's RCRA program has enlisted the experience and expertise of the Environmental Finance Advisory Board (EFAB) to evaluate specific issues related to financial responsibility. EFAB has completed assessments of the corporate financial test and captive insurance, and is currently in the process of undertaking analyses of third-party insurance and uncertainties associated with estimating costs that must be covered by the financial assurance requirements. In January 2006, the EFAB summarized its findings and recommendations on the corporate financial test, as a means of demonstrating financial assurance. EFAB's recommendations in this area were not based on specific failures of the test, but on their ''knowledge of prudent financial practices and the availability of existing expertise in the financial services sector.'' In March 2007, the EFAB summarized its preliminary findings and conclusions on its review of insurance, specifically captive insurance, as a means of demonstrating financial assurance. The Agency plans to continue to track these efforts by the EFAB, because they may provide key directions for future GS requirements with respect to financial responsibility.

EPA is considering updating mechanisms for demonstrating financial responsibility for GS projects. EPA is evaluating revising guidance to address the current financial responsibility requirements on the following topics: Cost estimation for plugging, pay-in period for trust funds, insurance providers, surety bonds and/or their providers, and corporate demonstration of financial strength/credit worthiness.

Cost estimation for plugging: One of the most critical aspects to ensuring that owners or operators have the resources to pay for injection well plugging is cost estimation. Sound cost estimation requirements ensure that sufficient funds are set aside in the financial assurance instrument to properly undertake covered activities (e.g., plugging and post-injection site care) at any time during the operating life of the facility and during the post-injection site care period.

EPA is assessing whether the cost estimate underpinning financial assurance should be based on the cost of retaining an independent, third party to conduct covered activities, such as well plugging. EPA also is considering provisions for annual inflationary adjustments and is weighing the inclusion of a third-party certification requirement, or provisions for a third-party audit, in cases where the owner or operator self-prepares its cost estimate. Revision in this area will reduce the possibility of undervalued cost estimates. EPA will also consider EFAB's findings on this issue when they become available.

Pay-in period for trust funds: Current UIC guidance describes trust funds as a form of financial assurance. The owner or operator may deposit funds into the trust fund in phases; that is, either over the term of the initial permit or over the remaining operating life of the injection well, as estimated in the well plugging plan, whichever period is shorter. Because of the possibility that the owner or operator may face financial distress prior to the trust being fully funded, EPA is considering a guidance approach that would recommend adopting a pay in period of three years for GS projects, consistent with other similar programs in the Agency.

Insurance providers: Current UIC regulations for Class I hazardous waste injection allow for the use of insurance for purposes of demonstrating financial responsibility. However, insurance was not included as part of the guidance provided for Class II injection because this insurance mechanism was and still is, rarely used for the purpose of demonstrating financial assurance for injection wells. EPA is assessing whether to provide guidance on the use of insurance providers and, if so, whether to update eligibility requirements for insurers for GS wells consistent with other current Federal agency practices.

In addition, EPA is evaluating recommendations from the Office of the Inspector General (OIG), the Government Accountability Office (GAO), and EFAB on the use of insurance as a financial responsibility mechanism. EPA will also consider any additional recommendations EFAB may have on the use of third party insurance.

Surety bonds and/or their providers: Current UIC guidance describes several options for using surety bonds for purposes of demonstrating financial responsibility. The regulations at 40 CFR 144 for Class I wells stipulate that eligible surety bond providers must be listed by the U.S. Department of Treasury on its Circular 570. Because surety bonds are a specialized line of insurance, EPA is assessing whether additional eligibility requirements for sureties, similar to those under consideration for insurers, are necessary for GS wells.

Corporate demonstration of financial strength/credit worthiness: UIC program guidance also describes options for owners or operators to self-assure their obligations to plug the well. To be approved by the Director, the owner or operator would likely need to self-assure in the form of either a corporate financial test filed by the owner or operator of the injection well, or a corporate guarantee (including a corporate financial test) filed by the parent corporation of the owner or operator of the injection well. A corporate guarantee may also be provided by a ''sibling'' corporation (that is a company that shares the same higher-tier parent) or a company with whom they have a substantial business relationship. The guidance explains that demonstrating self-assurance typically includes either use of a bond rating or a series of financial ratios. Both the UIC financial responsibility provisions for Class I hazardous waste injection and the RCRA subtitle C provisions allow the use of self-assurance through a financial test or corporate guarantee.

EPA is assessing whether a financial ratings threshold for all companies using a self-guarantee, similar to those used by other Federal agencies, is appropriate. The Agency also is considering what constitutes an appropriate financial rating threshold, and whether a financial rating greater than BBB or Baa (i.e., the current rating threshold established under the UIC regulations) is appropriate for GS wells.

In addition, EPA is considering whether adjustments should be made to the absolute net worth threshold of $10 million currently required under the UIC regulations. Specifically, EPA is assessing the net worth requirements of other Federal agencies and EPA programs to determine whether to make adjustments. For example, the Minerals Management Service within the Department of the Interior, requires a net worth threshold at least 10 times the amount of the obligations being assured (see 30 CFR 253.25). Additionally, the Agency is in the process of evaluating potential changes to the RCRA subtitle C financial test requirements, including an option recommended by EFAB to require a financial ratings threshold for all companies using a financial test to self-assure their environmental obligations. EPA will consider the outcome of that process for possible application to GS wells guidance.

EPA is requesting comments on whether financial responsibility mechanisms to be recommended in EPA guidance should be adjusted in the manner described, whether additional instruments should be included, and whether other adjustments to the financial responsibility mechanisms should be considered, all subject to EPA's authority under the SDWA. The Agency is also requesting comment on allowing separate financial demonstrations to be submitted for the plugging of the injection well and for the post-injection site care requirements. Since post-injection site care has the potential to extend many years into the future, subsequent to the time a permit is issued, the Agency believes that it may be advantageous to require the approval of the well plugging financial demonstration at permit issuance and the post-injection site care financial demonstration at a later time (e.g., within 180 days of notifying the Director that the well will be plugged and abandoned). Trying to determine the cost for post-injection site care, possibly 30 to 50 years in the future, could be difficult, as could the approval of a financial demonstration.

Considerations for Long-term Care: While EPA has authority to require financial responsibility for well plugging and post-injection site care (e.g., monitoring, remediation) to ensure the protection of USDWs, the SDWA does not provide authority under financial responsibility or other provisions for coverage of risks to air, ecosystems, or public health. Thus, while obligation for financial responsibility ends for owners or operators after the post-injection site care period has ended and the Director has authorized site closure, owners or operators may still be held responsible after the post-injection site care period has ended (e.g., for unanticipated migration that endangers a USDW). In addition, the SDWA does not provide EPA with the authority to transfer liability from one entity to another. Trust responsibility for potential impacts to USDWs remains with the owner or operator indefinitely under current SDWA provisions.

Responsibility for long-term care is often considered an important topic related to GS because of cost implications of indefinite responsibility for GS sites. Because of the focus of the SDWA on endangerment to USDWs and the absence of provisions to allow transfer of liability, stakeholders have expressed interest in alternative instruments for addressing financial responsibility after the post injection care period has ended. As a result of the interest in alternative instruments, including indemnity programs, EPA has compiled information on a variety of alternative instruments not currently available under the SDWA. This discussion is in *Approaches to GS Site Stewardship After Site Closure* in the docket for this proposed rule. EPA has not determined whether any of the models are appropriate for GS wells, however, EPA is aware that these models may contain important concepts that may become the model for future strategies for long-term care.

B. Adaptive Approach

To meet the potentially fast pace of implementation of GS, EPA is using an adaptive approach to regulating CO_2 injection for GS. In 2007, EPA issued UIC Program Guidance #83, which allows limited-scale experimental GS projects to proceed under the Class V experimental technology well classification. An adaptive approach allows regulatory development to move ahead in time to meet the future demand for permits, while recognizing the need to continue to gather data from pilot projects and other research as it becomes available.

EPA will continue to evaluate ongoing research and demonstration projects, review input received on this proposal, and gather other relevant information, as needed, to make refinements to the rulemaking process. If appropriate, EPA will publish notices to collect new data before issuing a final rule on CO_2 injection for GS. EPA plans to issue a final rule in advance of full-scale deployment of GS. EPA will track implementation of the final GS rule to determine whether these requirements continue to meet SDWA objectives and, if not, revise them as needed. If new information gathered during implementation suggests the requirements need revisions, EPA will initiate the appropriate procedure, including public notice and comment.

IV. How Should UIC Program Directors Involve the Public in Permitting Decisions for GS Projects?

Public participation has been an important part of the UIC Program since its inception. Public participation has a number of benefits, including (1) providing citizens with access to decision-making processes that may affect them; (2) enabling the owner/operator and the permit writer to educate the community about the project; (3) ensuring that the public receives adequate information about the proposed injection; (4) allowing the permitting authority to become aware of public viewpoints, preferences and environmental justice concerns; and (5) ensuring that public viewpoints, preferences and concerns have been considered by the 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. Critical to the success of GS is early and frequent involvement through education and information exchange. Such exchange can provide early insight into how the local community and surrounding communities perceive potential environmental, economic or health effects.

Owners or operators and permitting authorities can maximize the public participation process, thereby increasing the likelihood of success, by integrating social, economic, and cultural concerns of the community into the permit decision making process.

EPA examined existing requirements for public participation across the Agency's environmental programs. EPA is proposing to adopt the requirements at 40 CFR Part 25 and the permit procedures at 40 CFR Part 124 for long-term storage of CO_2. Under today's proposal, the permitting authority would be required to provide public notice and opportunity for public input. This includes providing public notice of pending actions via newspaper advertisements, postings, or mailings to interested parties and providing a fact sheet or statement of basis that describes the planned injection operation and the principal facts and issues considered in preparing the draft permit. Under today's proposal, permitting authorities would provide a 30-day comment period during which public hearings may be held. At the conclusion of the comment period, the permitting authority would be required to prepare a responsiveness summary that becomes part of the public record.

EPA recognizes that advances in information technology and the available avenues for communication have changed the way that people receive news and information and that new means of engaging stakeholders are now available. Roundtables, constituency meetings, charrettes (workshops designed to involve the public in a planning or design process), information gathering sessions, cable TV, and the Internet are just a few tools the Agency has come to rely upon over the past decade to ensure more effective stakeholder involvement and public participation. These technologies provide a host of opportunities to educate the public about and involve them in GS technology and pending decisions.

In addition, electronic information technology has become widely available to inform and involve the public. Web pages, discussion boards, list serves, and broadcast text messages via cell phones are all available to keep the public informed.

EPA encourages permit applicants and permit writers to use the Internet and other available tools to explain potential GS projects; describe the technology; and post information on the latest developments including schedules for hearings, briefings, and other opportunities for involvement.

EPA requests comment on adopting the existing requirements for public participation at 40 CFR Part 25 and 40 CFR Part 124 and whether additional requirements should be included to reflect the availability of new tools for disseminating and gathering information. Such tools include cable networks, the Internet, and other new technology. EPA also requests comment on ways to enhance the public participation process, including engaging communities in the site characterization process as soon as candidate locations are identified.

V. How Will States, Territories, and Tribes Obtain UIC Program Primacy for Class VI Wells?

As described in section II.C above, EPA may approve primary enforcement authority for States, Territories, and Tribes that wish to implement the UIC Program. To gain authority for Class VI wells, States, Territories, and Tribes will be required to show that their regulations are at least as stringent as, and may be more stringent than, the proposed minimum Federal requirements (e.g., inspection, operation, monitoring, and recordkeeping requirements that well owners or operators must meet). Such Primacy States, Territories, and Tribes are authorized under section 1422 of the SDWA.

Historically, EPA has approved State and Territorial UIC Program primacy in whole or in part as follows: (1) For all five classes of wells under section 1422 of SDWA; (2) for Classes, I, III, IV, and V under Section 1422 of SDWA; or for (3) Class II wells only under section 1425 of SDWA. Several States with large Class II inventories may have primacy for a combination of wells, i.e., authority under section 1425 for their Class II wells and 1422 authority for other well classes.

EPA is aware that some States may wish to obtain primacy for only Class VI wells. Section 1422 does not explicitly allow for approval of State UIC programs for individual well classes, however there appears to be no express prohibition.

There may be benefits to parsing out primacy for Class VI wells, however EPA has not made a decision on this. Allowing States, Territories, and Tribes to acquire primacy for only Class VI wells may encourage them to assume the responsibility of implementation and provide for a more comprehensive approach to managing CCS projects (e.g., capture, transportation, and geologic sequestration). EPA is seeking comment on the merits and possible disadvantages of allowing primacy approval for Class VI wells independent of other well classes.

VI. What Is the Proposed Duration of a Class VI Injection Permit?

Existing UIC regulations allow injection wells to be permitted individually or as part of an area permit. Because GS projects would likely use multiple injection wells per project, the Agency anticipates that most owners or operators would seek area permits for their injection wells.

Additionally, 40 CFR 144.36 sets forth the permit duration for the current classes of injection wells. Permits for Class I and Class V wells are effective for up to 10 years. Permits for Class II and III wells may be issued for the operating life of the facility; however they are subject to a review by the permitting authority at least once every 5 years.

Implementation of the AoR and corrective action plan as described in today's proposal would involve periodic re-evaluation of site data, status of corrective action, monitoring results and modification of operating parameters, as needed. These periodic evaluations would provide the same effect and assurances obtained through the permit renewal process without the associated administrative burden. Additionally, the frequent level of ongoing interaction between the owner or operator and the Director as required by the AoR and corrective action plan is more substantial than that required for other classes of injection wells. The periodic evaluations and revisions driven by the various rule-required plans and the underlying computational model should provide abundant opportunities for technical reassessment by operators and regulators, and through permit amendments and modifications.

Therefore, EPA proposes that Class VI injection well permits would be issued for the operating life of the GS project including the post-injection site care period. EPA seeks comment on the merits of this approach.

VII. Cost Analysis

While today's proposed rulemaking proposes regulations for the protection of USDWs, it does not require entities to sequester CO_2. Thus, the costs and benefits associated with protection of USDWs is the focus of this proposed rule and the costs associated with the mitigation of climate change are not directly attributable to this proposed rulemaking.

To calculate the costs and benefits of compliance for today's proposal, 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 proposal.

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

The scope of the Cost Analysis includes the full range of 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 time frame of the analysis. The scope does not include capturing or purifying the CO_2, nor does it include transporting the CO_2 to the GS site.

The 25-year timeframe of the Cost Analysis is comparable to the timeframes used in recent drinking water-related economic analyses. Costs attributed to the proposed rule are inclusive of geologic sequestration projects begun during the 25 years of the analysis and all cost elements that occur during the 25-year timeframe are discounted to present year values. EPA recognizes the need to revisit the Cost Analysis prior to the promulgation of a final rule as new data become available. The number of GS projects projected over the timeframe of the Cost Analysis includes pilot projects and other projects driven by regulations that are in place today. Projections of GS projects may need to be revisited in light of any new climate change legislation prior to promulgation of a final rule. However, it is important to note that the proposed rule does not require anyone to inject CO_2.

A. National Benefits and Costs of the Proposed Rule [1]

1. National Benefits Summary

This section summarizes the risk (and benefit) tradeoffs between compliance with existing requirements and the preferred regulatory alternative (RA) selected during the regulatory development process. Evaluations in the Cost Analysis include a non-quantitative analysis of the relative risks of contamination to USDWs for the regulatory alternatives under consideration. The expected change in risk based on promulgation of the preferred RA and the potential nonquantified benefits of compliance with this RA are also discussed.

a. Relative Risk Framework—Qualitative Analysis

Table VII–1 below presents the estimated relative risks of the preferred regulatory alternative selected for compliance with the proposed rule relative to the baseline. The term ''baseline'' in the exhibit refers to risks as they exist under current UIC Program regulations for Class I industrial wells. The term ''decrease'' indicates the change in risk relative to this baseline. The Agency has used best professional judgment to qualitatively estimate the relative risk of each regulatory alternative. 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 VII–1.—RELATIVE RISK OF REGULATORY COMPONENTS FOR PREFERRED PROPOSED REGULATORY ALTERNATIVE VERSUS THE CURRENT REGULATIONS

Baseline	Direction of change in risk (relative to baseline)
1. Geologic Characterization	
Geologic system consisting of a receiving zone; trapping mechanism; and confining system to allow injection at proposed rates and volumes.	Decrease.
Operators 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.	
2. Area of Review (AoR) Study and Corrective Action	
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 the greatest risk to USDWs.	Decrease.
3. Injection Well Construction	
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.	Decrease.
4. Well Operation	
Limit injection pressure to avoid initiating new fractures or propagate existing fractures in the confining zone adjacent to the USDWs.	Decrease.
5. Mechanical Integrity Testing (MIT)	
Demonstrate internal and external mechanical integrity, conduct a radioactive tracer survey of the bottom-hole cement, and conduct a pressure fall-off test every 5 years.	Decrease.
6. Monitoring	
Monitor the nature of injected fluids at a frequency sufficient to yield data representative of their characteristics; Conduct ground water monitoring within the AoR. Report semi-annually on the characteristics of injection fluids, injection pressure, flow rate, volume and annular pressure, and on the results of MITs, and ground water and atmospheric monitoring.	Decrease.
7. Well Plugging	

[1] 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.

TABLE VII–1.—RELATIVE RISK OF REGULATORY COMPONENTS FOR PREFERRED PROPOSED REGULATORY ALTERNATIVE VERSUS THE CURRENT REGULATIONS—Continued

Baseline	Direction of change in risk (relative to baseline)
Ensure that the well is in a state of static equilibrium and plugged using approved methods. Plugs shall be tagged and tested. Conduct post-injection site care monitoring to confirm that CO_2 movement is limited to intended zones.	Decrease.
8. Financial Responsibility	
Demonstrate and maintain financial responsibility and resources to plug the injection well and for post-injection site care.	Decrease.
Overall	Decrease.

Note: See Chapter 2 of the GS proposed rule Cost Analysis for a detailed description of the components for each regulatory alternative.

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

As shown in Table VII–1, EPA estimates that under the Preferred Alternative, RA3, risk will decrease relative to the baseline for each of the eight components assessed.

b. Other Nonquantified Benefits

Promulgation of the proposed rule will result in direct benefits, that is, protection of the USDWs which EPA is required by statute to protect; and indirect benefits, which are those protections afforded to entities as a by-product of protecting USDWs. Indirect benefits are described in the *Risk and Occurrence Document for Geologic Sequestration Proposed Rulemaking* (USEPA, 2008e) and summarized 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 potential climate change mitigation are not included in the assessment.

2. National Cost Summary

a. Cost of Preferred Regulatory Alternative

EPA estimated the incremental, one-time, capital, and operation and maintenance (O&M) costs associated with today's proposed rulemaking. As Table VII–2 shows, the total incremental cost associated with the Preferred Alternative is $15.0 million and $15.6 million, using a 3 percent and 7 percent discount rate, respectively. These costs are in addition to the baseline costs that would be incurred if CO_2 sequestration was instead subject to the current rules for UIC Class I industrial wells. As can be seen from Table VII–2, today's proposed rule would increase the costs of complying with UIC regulations for these wells from approximately a baseline of $32.3 million to $47.3 million using a 3 percent discount rate, which is an increase of 46%. EPA believes these increased costs are needed to address the unique issues associated with CO_2 geological sequestration. The costs of the other regulatory alternatives considered are detailed in the Cost Analysis, along with a discussion of how EPA derived these estimates.

TABLE VII–2.—INCREMENTAL COSTS OF PREFERRED REGULATORY ALTERNATIVE FOR 22 PROJECTS

[2007$, $million]

Regulatory alternative	One-time costs	Capital costs	O&M costs	Total
	3 Percent Discount Rate			
Baseline	$2.5	$10.6	$19.2	$32.3
Alternative 3	3.8	15.5	28.1	47.3
Alt 3—Incremental	1.3	4.9	8.8	15.0
	7 Percent Discount Rate			
Baseline	$2.9	$12.7	$18.0	$33.6
Alternative 3	4.2	18.6	26.4	49.2
Alt 3—Incremental	1.3	5.9	8.4	15.6

Table VII–3 presents a breakout of the incremental costs of the Preferred Alternative by rule component.

- Monitoring activities account for 60 percent of the incremental regulatory costs. Most of this cost is for the construction, operation, and maintenance of corrosion-resistant monitoring wells. This cost also 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 Preferred Alternative is injection well operation, accounting for 22 percent of the total incremental cost. This component ensures that the wells operate within safety parameters and the injection does not cause unacceptable fluid movement.
- Well plugging and post-injection site care activities, which ensure that the injection well is properly closed in a way that addresses the corrosive

nature of the CO_2 and does not allow it to serve as a conduit for fluid movement, account for 5 percent of the total incremental cost of RA 3.

- Mechanical Integrity Testing, including continuous pressure monitoring, which can provide timely warning that CO_2 may have compromised the well, accounts for an additional 4 percent of the cost.
- Construction of GS wells using the corrosion resistant design and materials necessary to withstand exposure to CO_2 accounts for 4 percent of the incremental cost of the Preferred Alternative.

TABLE VII–3.—INCREMENTAL RULE COSTS OF PREFERRED REGULATORY ALTERNATIVE FOR 22 PROJECTS BY RULE COMPONENT

[2007$, $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	Financial responsibility [1]	Permitting authority admin	Total
	3 Percent Discount Rate									
Baseline	$0.7	$1.8	$10.4	$0.6	$18.5	$0.1	$0.1	$0.0	$0.1	$32.3
Alternative 3	1.2	10.9	11.0	0.7	21.8	0.7	0.9	0.0	0.1	47.3
Alt 3 Incremental	0.4	9.1	0.6	0.1	3.3	0.6	0.8	0.0	0.0	15.0
Incremental—% of Total	3%	60%	4%	1%	22%	4%	5%	0%	0%	100%
	7 Percent Discount Rate									
Baseline	$0.9	$2.1	$12.5	$0.6	$17.3	$0.1	$0.1	$0.0	$0.1	$33.6
Alternative 3	1.4	12.0	13.3	0.8	20.3	0.7	0.7	0.0	0.1	49.2
Alt 3 Incremental	0.5	9.9	0.8	0.2	3.0	0.6	0.6	0.0	0.0	15.6
Incremental—% of Total	3%	63%	5%	1%	19%	4%	4%	0%	0%	100%

[1] Costs related to demonstration of Financial Responsibility are less than $100,000 in annualized terms.

b. Nonquantified Costs and Uncertainties in Cost Estimates

The purpose of the GS proposed rule is to mitigate any risk introduced by CO_2 GS activity to the quality, and indirectly the quantity, of current and potential future USDWs. Furthermore, the rule proposes requirements that are intended to provide redundant safeguards. In the rare case where the rule, if finalized, is non-implementable or not readily comprehensible, contamination could occur to a USDW. In that case, the cost of cleaning up the USDW or finding an alternative source of drinking water could be attributable to the rule. Based on data from States regarding implementation of the UIC program and current research, EPA considers the likelihood of this occurring very small, and has not quantified this risk.

Should the final GS rule somehow impede CO_2 GS from happening, then the opportunity costs of not capturing the benefits associated with GS of CO_2 could be attributed to the regulations; however, the Agency has tried to develop a proposed rule that balances risk with practicability and economic considerations, and believes the probability of such impedance is very low. If finalized, the GS rule would ensure protection of USDWs from 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 proposed rule will not impede CO_2 GS from happening and has not quantified such risk.

Uncertainties in the analysis are included 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 proposed rule; (2) the labor rates applied; and (3) the estimated number of monitoring wells to be constructed per injection well to adequately monitor in a given geologic setting.

First, the number of projects that will deploy from 2012 through 2036 may be significantly underestimated in this analysis given the uncertainty in future deployment of this technology. The current baseline assumption is that 22 projects will deploy during the 25-year period, as described in Chapter 3 of the proposed rule Cost Analysis and explained in detail in the Geologic CO_2 Sequestration Activity Baseline (USEPA, 2008f) document.

Second, the labor rate adopted for each of the labor categories described in Section 5.2.1 of the Cost Analysis (Geoscientist, Geological Engineer, State Geologist, and Agency Geologist) may be underestimated. The practice of CO_2 injection represents an activity that, although already practiced widely in some contexts (i.e., EOR), is expected 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, resulting in rapid cost escalation for many of the cost components discussed in this chapter. (Anecdotal evidence based on discussions with industry representatives suggests that there may already be labor shortages developing in some critical disciplines.) Because the cost analyses presented in this chapter are based on current industry costs, the level and pace of price responses as the level of CO_2 GS increases represent a highly uncertain component in the cost estimates presented in this chapter.

Third, the Agency assumes three monitoring wells per injection well for the purpose of estimating national costs; 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. EPA requests comment on whether three monitoring wells per injection well is an appropriate costing assumption.

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 GS proposed rule Cost Analysis.

c. Supplementary Cost Information

To better establish the context in which to evaluate the Cost Analysis for this proposal, we consider three types of costs that are not accounted for explicitly for this proposed rule: (1) Costs that are incurred beyond the 25-year timeframe of the Cost Analysis, (2) costs that could arise due to a higher rate of deployment of CCS in the future, and (3) the proportion of overall CCS costs attributable to the proposed requirements. Because geologic sequestration of CO_2 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 impact of these costs below.

The Cost Analysis for this proposed rule explores costs that might be incurred during a 25-year timeframe.[2] When analyzing costs for a commercial size sequestration project that begins in year one of the Cost Analysis, EPA assumes that the first year is a construction period, followed by 20 years of injection, followed by 50 years of post-injection site care as indicated in the proposal. The 20-year injection period reflects the assumption that a source such as a coal-fired power plant, with a potential operational lifetime of 40 to 60 years, would plan for the sequestration of only half of its emissions at a time, rather than incur those costs all at once. EPA requests comment on this assumption. Given the 25-year timeframe of the analysis, only the first four years of post-injection care period would be captured in the Cost Analysis for a project beginning in year 1, and fewer or no years of post-injection care for a project beginning later in the 25-year analytical time frame. Based on estimates of the first four years of the post-injection care period, EPA estimates that the average costs for one large deep saline project incurred beyond the 25-year timeframe of the Cost Analysis are approximately \$0.30/t CO_2 for the remaining 46 years of post-injection site care. The full amount of the 46 years of post-injection site care is incremental to the baseline. The incremental sequestration costs above the baseline, over the full lifetime of the sequestration project, are estimated to be \$1.20/t CO_2. Thus the 25-year timeframe captures approximately 75% of the lifetime incremental costs associated with implementing this rule. It should be noted that the longer the time horizon over which costs are estimated, the greater the uncertainty surrounding those estimates.

The Cost Analysis assumes that 22 projects will inject 350 Mt CO_2 cumulatively over the next 25 years.[3] The start years of these projects, for both pilot and large sizes, are staggered over the 25 years.[4] Based on the assumed deployment schedule, the analysis captures the full injection periods for three large-scale projects (with an injection period of 20 years), 12 pilot projects (with an injection period of seven years), and partial injection periods for the remaining seven projects. While the baseline injection amount represents a significant step towards demonstrating the feasibility of CCS, it represents a small amount of current CO_2 emissions in the U.S.

The U.S. fleet of 1,493 coal-fired generators emits 1,932 Mt CO_2 per year. The technical or economic viability of retrofitting these or other industrial facilities with CCS is not the subject of this proposed rulemaking. However, if some percentage of these facilities undertook CCS, they (or the owner or operator of the CO_2 injection wells) would be subject to the UIC requirements. For example, if 25% of these facilities undertook CCS (assuming a 90% capture rate and the incremental proposed rule sequestration costs outlined in Table VII–4) the incremental sequestration costs associated with meeting the proposed Class VI requirements, assuming they are finalized, would be on the order of \$500 million. Similarly, if 100% of these plants undertook CCS, the incremental costs would be on the order of \$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 proposed rule that 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 proposal, due to the uncertainty of what percentage, if any, of such facilities will deploy CCS in the future. These estimates represent a snapshot of potential costs assuming 25% or 100% 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.

Based on current literature, sequestration costs are expected to be a small component of total CCS project costs. Table VII–4 shows example total 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/t CO_2 for capture from an Integrated Gasification Combined Cycle power plant[5]). Transportation costs vary widely depending on the distance from emission source to sequestration site, but we can use a long-term average estimate of \$3/t CO_2.[6] We estimate total sequestration costs for a commercial size deep saline project to be approximately \$3.40/t CO_2, of which approximately \$1.20/t CO_2 is attributable to complying with requirements of this proposed rule (including the full 50 years of post-injection site care). Based on the project costs outlined in Table VII–4, the proposed requirements amount to approximately 3% of the total CCS project costs.

[2] A detailed discussion of timeframe over which the proposed requirements were estimated can be found in the Cost Analysis.

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

[4] A detailed table of the scheduled deployment of projects assumed in the baseline over the 25-year timeframe can be found in Exhibit 3.1 of the Cost Analysis.

[5] Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL–2007/1281, May 2007.

[6] On the Long-Term Average Cost of CO_2 Transport and Storage, JJ Dooley, RT Dahowski, CL Davidson, Pacific Northwest National Laboratory Operated for the U.S. Department of Energy by Battelle Memorial Institute, PNNL–17389, March 2008.

TABLE VII–4.—EXAMPLE TOTAL 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 ($\$/tCO_2$)	Percentage of total CCS project cost (%)
Capture (IGCC plant)	$42.00	87
Transportation Estimate	3.00	6
Baseline Sequestration	2.20	4
Incremental Proposed Rule Sequestration Requirements	1.20	3
Total CCS Project Cost	48.40	

B. Comparison of Benefits and Costs of Regulatory Alternatives of the Proposed Rule

a. Costs Relative to Benefits; Maximizing Net Social Benefits

Because EPA lacks the data to perform a quantified analysis of benefits, a direct numerical comparison of costs to benefits cannot be done. Costs can only be compared to qualitative relative risks as discussed in section VII–1.

Compared to the baseline, RA3 provides greater protection to USDWs because it is specifically tailored to the injection of CO_2. The current regulatory requirements do not specifically consider the injection of a buoyant corrosive fluid. In particular, RA3 includes increased monitoring requirements that provide the amount of protection the Agency estimates is necessary for USDWs. As described in the prior section (A. National Benefits and Costs of the Proposed Rule), monitoring requirements account for 60 percent of the incremental regulatory costs, of which 70 percent is incurred for the construction, operation, and maintenance of monitoring wells, and the other 30 percent for tracking of the plume and pressure front through complex modeling at a minimum of every 10 years for all operators (the cost model assumes every 5 years) and monitoring for CO_2 leakage. Public awareness of these protective measures would be expected to enhance public acceptance of CO_2 GS.

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.

b. 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 best alternative.

C. Conclusions

RA3 provides a high level of protection to USDWs overlying injection zones of CO_2. It does so at lower costs than the more stringent RA4 while providing significantly more protection than RA1 or RA2. Therefore EPA believes RA3 is the preferred regulatory alternative. The Agency seeks comment on cost assumptions in today's proposal.

VIII. Statutory and Executive Order Reviews

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 proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2309.01.

The information collected as a result of this proposed rule will allow EPA and State permitting authorities to review geologic information about a proposed GS site to evaluate its suitability for safe and effective GS. It also allows the Agency to verify throughout the life of the injection project that UIC protective requirements are in place and that USDWs are protected. The Paperwork Reduction Act requires EPA to estimate the burden on owners or operators of CO_2 GS wells, and States, Territories, and Tribes with primacy. Burden is defined at 5 CFR 1320.3(b).

For GS well operators applying for permits, this burden includes the time, effort, and financial resources needed to collect information to furnish EPA with the following information:

—UIC permit applications and information to support the site characterization, such as maps and cross sections, information on the geologic structure, hydrogeologic properties, and baseline geochemical data on the proposed site.
—AoR and corrective action plan.
—Testing and monitoring plan.
—Well plugging and post-injection site care plans.
—Emergency and remedial response plans.
—Reports of well logs and tests performed during well construction.
—Periodic updates to the AoR models and corrective action status.
—Demonstration of financial responsibility and periodic updates.
—Periodic reports of monitoring and testing.
—Reports of post-injection monitoring.
—Non-endangerment demonstrations and the conclusion of all post-injection site care.

For the first 3 years after publication of the final rule in the **Federal Register**, the major information requirements apply to operators of GS wells that are submitting an application for the construction of a CO_2 GS well (or seeking a Class VI permit for an existing well) or monitoring and MIT data during the operation of the GS project.

States and Tribes with primacy will incur burden associated with the following activities:

—Applying for primacy.
—Reviewing permit applications and associated data submitted by operators (including the testing and monitoring plan, AoR and corrective action plan, injection well plugging plan, post-injection site care and closure plan, and emergency and remedial response plan).
—Making decisions on whether to grant or deny permits and writing permits.
—Reviewing testing and monitoring data submitted by operators, e.g., continuous monitoring and MIT results.

For the first 3 years after publication of the final rule in the **Federal Register**, preparing primacy applications will account for the majority of primacy agency burden. This is a one-time burden to each State or Tribe that seeks primacy and, in subsequent ICRs, primacy agency burden is expected to decrease by approximately 90 percent.

The collection requirements are mandatory under the SDWA (42 U.S.C. 300h *et seq.*). Calculation of the information collection burden and costs associated with today's proposal can be found in the *Information Collection Request for the Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* (USEPA, 2008g), available through *http://www.regulation.gov* under Docket ID EPA–HQ–OW–2008–0390.

As shown in Table VIII–1, the total burden associated with the proposed rule over the 3 years following promulgation is 62,117 hours, or an average of 20,706 hours per year. The total cost over this period is $7.3 million, or an average of $2.4 million per year. The average burden per response for each activity that requires a collection of information is 164 hours; the average cost per response is $19,310.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information request 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.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, EPA has established a public docket for this proposed rule under Docket ID number EPA–HQ–OW–2008–0390. Submit any comments related to the ICR to EPA and OMB. See **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after July 25, 2008, a comment to OMB is best assured of having its full effect if OMB receives it by August 25, 2008. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

TABLE VIII–1.—ANNUAL, TOTAL, AND ANNUAL AVERAGE BURDEN HOURS AND COSTS FOR THE PROPOSED RULE INFORMATION COLLECTION REQUEST 3-YEAR APPROVAL PERIOD

	Year 1	Year 2	Year 3	Total	Annual average
Total (Owners/Operators, Primay Agencies, and DI Programs/EPA Headquarters)					
Burden (in hours)	21,934.2	18,293.7	18,435.2	62,117.0	20,705.7
Respondents	24.3	28.2	29.9	47.0	27.5
Responses	131.0	113.0	129.0	378.0	126.0
Costs ($)	$3,412,795	$2,428,168	$2,702,335	$7,299,064	$2,433,021
Labor ($)	$1,132,302	$877,087	$887,616	$3,145,843	$1,048,614
Non-Labor ($)	$2,280,493	$1,551,081	$1,814,719	$4,119,644	$1,373,215
Burden per Response	167.4	161.9	142.9	164.3	164.3
Cost per Response	$26,052	$21,488	$20,948	$19,310	$19,310
Burden per Respondent	901.4	648.4	615.9	1,321.6	753.1
Cost per Respondent	$140,252	$86,065	$90,278	$155,299	$88,495
Operators/Owners					
Burden (in hours)	5,359.5	2,118.0	2,228.5	13,160.0	4,386.7
Respondents	3.0	4.0	5.0	5.0	4.0
Responses	63.0	54.0	65.0	187.0	62.3
Costs ($)	$2,678,179	$1,711,130	$1,983,931	$5,129,006	$1,709,669
Labor ($)	$397,687	$160,049	$169,212	$975,786	$325,262
Non-Labor ($)	$2,280,493	$1,551,081	$1,814,719	$4,119,644	$1,373,215
Avg. Burden per Response	85.1	39.2	34.3	70.4	70.4
Avg. Cost per Response	$42,511	$31,688	$30,522	$27,428	$27,428
Burden per Respondent	1,786.5	529.5	445.7	2,632	1,096.7
Cost per Respondent	$892,726	$427,783	$396,786	$1,025,801	$427,417
Primacy Agencies					
Burden (in hours)	11,278.8	10,990.7	11,013.1	33,281.8	11,093.9
Respondents	10.3	13.2	13.9	31.0	12.5
Responses	36.3	29.8	33.4	99.4	33.1
Costs ($)	$475,547	$463,433	$464,374	$1,403,354	$467,785
Labor ($)	$475,547	$463,433	$464,374	$1,403,354	$467,785
Non-Labor ($)					
Burden per Response	311.1	369.1	330.0	1,010.2	336.7
Cost per Response	$13,117	$15,565	$13,915	$42,597	$14,199
Burden per Respondent	1,091.4	831.8	790.4	2,713.6	904.5

TABLE VIII–1.—ANNUAL, TOTAL, AND ANNUAL AVERAGE BURDEN HOURS AND COSTS FOR THE PROPOSED RULE INFORMATION COLLECTION REQUEST 3-YEAR APPROVAL PERIOD—Continued

	Year 1	Year 2	Year 3	Total	Annual average
Cost per Respondent	$46,021	$35,073	$33,328	$114,422	$38,141
DI Programs/EPA Headquarters					
Burden (in hours)	5,296.6	5,184.9	5,193.6	15,675.2	5,225.1
Respondents	11.0	11.0	11.0	11.0	11.0
Responses	31.7	29.2	30.6	91.6	30.5
Costs ($)	$259,069	$253,605	$254,029	$766,703	$255,568
Labor ($)	$259,069	$253,605	$254,029	$766,703	$255,568
Non-Labor ($)					
Burden per Response	166.8	177.4	169.6	171.1	171.1
Cost per Response	$8,161	$8,677	$8,294	$8,370	$8,370
Burden per Respondent	481.5	471.4	472.1	1,425.0	475.0
Cost per Respondent	$23,552	$23,055	$23,094	$69,700	$23,233

Note: Numbers may not appear to add due to rounding.

C. Regulatory Flexibility Act (RFA)

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure 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 proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) 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 (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This proposed rule will not impose any requirements on small entities. Sequestering CO_2 via injection wells is a voluntary action that would only be undertaken by a small entity if it were in its interest compared to other alternatives it may have. GS of CO_2 is still a scientifically 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. We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA regulation for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Based on the analysis of 22 pilot projects, EPA has determined that this proposed 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. Expenditures associated with compliance for these projects, defined as the incremental costs beyond the existing regulations under which a CO_2 GS well could be permitted and deployed, will not surpass $100 million in the aggregate in any year. Thus, today's proposed rule is not subject to the requirements of sections 202 and 205 of UMRA. However, EPA recognizes that if CCS is used more widely, the incremental costs of the requirements associated with this rule could exceed $100 million in the aggregate in some years. EPA will determine the applicability of UMRA for the final rule and provide any necessary analysis.

EPA has determined that this proposed rule contains no regulatory requirements that might significantly or uniquely affect small governments. Most regulated entities are anticipated to be private entities, not governments.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have Federalism implications.'' ''Policies that have Federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This proposed rule does not have Federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Currently, States may gain the authority to regulate a full or partial UIC program in their State by applying for primacy. States with primacy must develop a program incorporating all new Federal requirements for Class VI wells if they wish to regulate CO_2 GS, and all programs will be subject to EPA approval. Since application for primacy is a voluntary process, the addition of this proposed regulation to the UIC regulations should not significantly impact States or their right to primacy for other classes of wells. If States do not develop a program for Class VI wells, EPA will oversee CO_2 GS in those States. Thus, Executive Order 13132 does not apply to this proposal.

Although section 6 of Executive Order 13132 does not apply to this rule, EPA did consult with State and local officials early in the process of developing this proposed rule to permit them to have meaningful and timely input in its development. EPA sent letters with background about the rulemaking and an invitation for consultation to 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. EPA held a meeting with interested parties from these organizations in April 2008.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials. A summary of the concerns raised during that consultation and EPA's response to those concerns will be provided in the preamble to the final rule.

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

Executive Order 13175, entitled ''Consultation and Coordination With Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This proposed rule does not have tribal implications as specified in Executive Order 13175. Currently, no Indian Tribes have primacy. However, Indian Tribes may acquire authority to regulate a partial or full UIC program in lands under their jurisdiction by applying for and gaining primacy from the Agency. Tribes seeking primacy must develop requirements at least as stringent as the new proposed Federal requirements for Class VI wells if they wish to regulate CO_2 GS, and all programs will be subject to EPA approval. If Tribes do not develop a program for Class VI wells, EPA is responsible for regulating the GS of CO_2 on tribal lands. The application for primacy is a voluntary process. Furthermore, this proposal clarifies regulatory ambiguity rather than placing new requirements on tribal or other governmental entities. Therefore, this proposed rule should not change the Tribal-Federal relationship and should not significantly impact Tribes. Thus, Executive Order 13175 does not apply to this proposed rule.

Although Executive Order 13175 does not apply to this proposed rule, EPA consulted with tribal officials in developing this proposed rule. EPA sent letters with background about the rulemaking and an invitation for consultation to all of the federally recognized Indian Tribes. EPA held a meeting with interested parties from Tribal governments in April 2008.

EPA specifically solicits additional comment on this proposed rule from tribal officials.

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 in EO 12866, and because the Agency does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. Moreover, this proposed rule will not require that CO_2 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. This action's health and risk assessments are contained in *Risk and Occurrence Document for Geologic Sequestration Proposed Rulemaking* (USEPA, 2008e).

The public is invited to submit comments or identify peer-reviewed studies and data that assess the effects of early life exposure to changes in drinking water quality that may be caused by geologic sequestration of carbon dioxide.

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

EPA has tentatively determined that this rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001) because application of these requirements to the 22 pilot projects is not likely to have a significant adverse effect on the supply, distribution, or use of energy. EPA will consider the potential effects of more widespread application of the rule requirements and make a final determination regarding EO 13211 applicability for the final rule (see UMRA discussion above).

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 to maximize operations (for example, by increasing production while staying within the emissions cap or avoiding some carbon taxes). The proposed 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 No. 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.

The proposed rulemaking involves technical standards. Therefore, the Agency conducted a search to identify potentially applicable voluntary consensus standards. However, we identified no such standards, and none were brought to our attention. Thus the Agency decided to convene numerous workshops (discussed further in Chapter 2 of the Cost Analysis for the GS proposed rule) to develop standards based on current information available from experts in industry, government, and non-governmental organizations. EPA proposes to use a combination of technologies and standard practices that it estimates will provide the necessary protection to USDWs with regard to site characterization, construction, operation, monitoring, closure, and post-closure requirements for CO_2 GS wells, without placing undue burden on well operators. These methods are listed in Chapter 2 of the Cost Analysis for the GS proposed rule and described in further detail in the *Geologic CO_2 Sequestration Technology & Cost Analysis* (USEPA, 2008h) developed in support of this proposed rule.

EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially applicable voluntary consensus standards and to explain why such standards should be used in this regulation.

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

Executive Order (EO) 12898 (59 FR 7629 (Feb. 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, any 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 proposed 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 without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

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. This proposed rule would not require that CO_2 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 proposed rule if finalized 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 proposed rule is presented in the *Risk and Occurrence Document for Geologic Sequestration Proposed Rulemaking* (USEPA, 2008e).

EPA believes that UIC permit writers should consider the impact of GS on any communities in the geographic areas of GS sites. Permit writers can ask specific questions to specifically address any potentially different impacts on minority and/or low-income communities. Examples include: In reviewing the application or Notice of Intent (NOI) for a GS permit, is there any indication that a minority and/or low-income community would be adversely affected? Are there measures that should be undertaken to understand minority and/or low-income community concerns during the permit drafting and development phase, including the development of permit conditions? If an environmental justice issue is identified, does the program solicit input and participation from minority and/or low-income populations?

EPA seeks comment on environmental justice considerations for GS permit writers.

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List of Subjects

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 146

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

Dated: July 15, 2008.

Stephen L. Johnson,

Administrator.

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

PART 144—UNDERGROUND INJECTION CONTROL PROGRAM

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

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

Subpart A—General Provisions

2. Section 144.1 is amended as follows:

a. Adding new paragraph (f)(1)(viii); and

b. Revising the first two sentences in paragraph (g) introductory text.

§ 144.1 Purpose and scope of part 144.

* * * * *

(f) * * *

(1) * * *

(viii) Subpart H of this part 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 injections 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. * * *

* * * * *

3. Section 144.6 is amended as follows:

a. Revising paragraph (e); and

b. Adding new paragraph (f).

§ 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 used for geologic sequestration of carbon dioxide beneath the lowermost formation containing a USDW.

Subpart B—General Program Requirements

4. Adding § 144.15 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.

5. Adding § 144.18 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 are not authorized by rule to inject.

Subpart D—Authorization by Permit

6. Section 144.36 is amended by revising the first two sentences in 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, III and VI wells shall be issued for a period up to the operating life of the facility. * * *

* * * * *

7. Section 144.39 is amended by revising the second sentence in paragraph (a) introductory text and by revising the second sentence in paragraph (a)(3) introductory text 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 terms for this cause only as follows: * * *

* * * * *

Subpart E—Permit Conditions

8. Section 144.51 is amended by revising the first sentence in paragraph (q)(1) and the first sentence in paragraph (q)(2) to read as follows:

§ 144.51 Conditions applicable to all permits.

* * * * *

(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 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 for Class VI of this chapter, he/she shall give written notice of his/her determination to the owner or operator. * * *

* * * * *

9. Section 144.52 is amended by revising paragraph (a)(8) to read as follows:

§ 144.52 Establishing permit conditions.

(a) * * *

(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 § 146.08 or § 146.89 for Class VI that the well has mechanical integrity.

* * * * *

10. Section 144.55 is amended by revising the first sentence in paragraph (a) to read as follows:

§ 144.55 Corrective action.

(a) *Coverage*. Applicants for Class I, II, (other than existing), III or VI injection well permits shall identify the location of all known wells within the injection well's area of review which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review penetrating formations affected by the increase in pressure. Applicants for Class VI shall perform corrective action as specified in § 146.84.* * *

* * * * *

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

11. 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.

PART 146—UNDERGROUND INJECTION CONTROL PROGRAM: CRITERIA AND STANDARDS

12. 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.*

13. Section 146.5 is amended as follows:

a. Revising the first sentence in paragraph (e) introductory text; and

b. Adding paragraph (f).

§ 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 used for geologic sequestration of carbon dioxide beneath the lowermost formation containing an underground source of drinking water (USDW).

14. 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 Class VI carbon dioxide geologic sequestration injection wells.

(b) This subpart applies to 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 applies to owners and operators of permit or rule-authorized Class I industrial, 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. If the Director determines that USDWs will not be endangered, such wells are exempt, at the Director's discretion, from the casing and cementing requirements at §§ 146.86(b) and 146.87(a)(1) through (3).

(d) *Definitions*. The following definitions apply to this subpart. To the extent that these definitions conflict with those in § 146.3 these definitions govern:

Area of review means the region surrounding the geologic sequestration project that may be impacted by the injection activity. The area of review is based on computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream.

Carbon dioxide plume means the underground extent, 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 that acts as a barrier to fluid movement.

Corrective action means the use of Director approved methods to assure that wells within the area of review do not serve as conduits for the movement of fluids into underground sources of drinking water (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 its 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. It includes the subsurface three-dimensional extent of the carbon dioxide plume, associated pressure front, and displaced brine, 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 assure 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 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.

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 the owner or operator must submit to the Director in order to be permitted as a Class VI well. The application for a permit for construction and operation of a Class VI well must include the following:

(a) Information required in 40 CFR 144.31(e)(1) through (6);

(b) A map showing the injection well(s) for which a permit is sought and the applicable area of review. 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 and other pertinent surface features including structures intended for human occupancy 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;

(c) The area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (l), (r), and (s) of this section;

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

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

(2) 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;

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

(4) 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;

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

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

(e) 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;

(f) 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;

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

(h) Proposed operating data:

(1) Average and maximum daily rate and volume of the carbon dioxide stream;

(2) Average and maximum injection pressure;

(3) The source of the carbon dioxide stream; and

(4) An analysis of the chemical and physical characteristics of the carbon dioxide stream;

(i) The compatibility of the carbon dioxide stream with fluids in the injection zone 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;

(j) Proposed formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone;

(k) Proposed stimulation program and a determination that stimulation will not interfere with containment;

(l) The results of the formation testing program as required in paragraph (j) of this section;

(m) Proposed procedure to outline steps necessary to conduct injection operation;

(n) Schematic or other appropriate drawings of the surface and subsurface construction details of the well;

(o) Injection well construction procedures that meet the requirements of § 146.86;

(p) Proposed area of review and corrective action plan that meets the requirements under § 146.84;

(q) The status of corrective action on wells in the area of review;

(r) All available logging and testing program data on the well required by § 146.87;

(s) A demonstration of mechanical integrity pursuant to § 146.89;

(t) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;

(u) Proposed testing and monitoring plan required by § 146.90;

(v) Proposed injection well plugging plan required by § 146.92(b);

(w) Proposed post-injection site care and site closure plan required by § 146.93(a);

(x) Proposed emergency and remedial response plan required by § 146.94; and

(y) Any other information requested by the Director.

§ 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 geologic system must be comprised of:

(1) An injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;

(2) A confining zone(s) that is 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); and

(b) At the Director's discretion, owners or operators of Class VI wells must 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 that may be impacted by the injection activity. The area of review is based on computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream.

(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. 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 10 years, 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, identify all wells that require corrective action, and perform corrective action on those wells:

(1) Predict, using 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, pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or after 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, confining zone and any additional zones; and anticipated operating data, including injection pressures, rates and total volumes over the proposed life of the geological sequestration project;

(ii) Take into account any geologic heterogeneities, 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. 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 (as required by § 146.92) in a manner that prevents the movement of carbon dioxide or associated fluids that may endanger USDWs.

(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 necessary to prevent the movement of fluid into or between USDWs including use of corrosion resistant materials, where appropriate.

(e) If monitoring data indicate an endangerment to USDWs, the owner or operator must notify the Director and cease operations as required by § 146.94.

(f) At the minimum fixed frequency, not to exceed 10 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)(2) 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 (c)(3) 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.

(g) The emergency and remedial response plan (as required by § 146.94) and a demonstration of financial responsibility (as described by § 146.85) must account for the entire area of review, regardless of whether or not corrective action in the area of review is phased.

§ 146.85 Financial responsibility.

(a) The owner or operator must demonstrate and maintain financial responsibility and resources for corrective action (that meets the requirements of § 146.84), injection well plugging (that meets the requirements of § 146.92), post-injection site care and site closure (that meets the requirements of § 146.93), and emergency and remedial response (that meets the requirements of § 146.94) in a manner prescribed by the Director until:

(1) The Director receives and approves the completed post-injection site care and site closure plan; and

(2) The Director determines that the site has reached the end of the post-injection site care period.

(b) The owner or operator must provide to the Director, at a frequency determined by the Director, written updates of adjustments to the cost estimate to account for any amendments to the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), and the post-injection site care and site closure plan (§ 146.93).

(c) The owner or operator must notify the Director 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.

(d) The operator must provide an adjustment of the cost estimate to the Director if the Director has reason to believe that the original demonstration is no longer adequate to cover the cost of injection well plugging (as required by § 146.92) and post-injection site care and site closure (as required by § 146.93).

§ 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 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;

(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 zones;

(viii) Type or grade of cement; 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.

(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) All owner and 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.

(2) 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);

(iii) Injection pressure;

(iv) Annular pressure;

(v) Injection rate (intermittent or continuous) and volume of the carbon dioxide stream;

(vi) Size of 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 assure 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 are enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to assure 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, 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, if required by the Director; and

(5) Any alternative methods that provide equivalent or better information and that are required of and/or approved of by the Director.

(b) The owner or operator must take and submit to the Director whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s). The Director may accept 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 the 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 zones; and

(3) Physical and chemical characteristics of the formation fluids in the injection zone.

(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone:

(1) A pump test; or

(2) 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 so as to assure that the injection does not initiate new fractures or propagate existing fractures in the injection zone. 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.

(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.

(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is of necessity 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 continuous recording devices to monitor: The injection pressure; the rate, volume, 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 must install and use alarms and automatic down-hole shut-off systems, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters approved by the Director diverge beyond permitted ranges and/or gradients specified in the permit;

(f) If a down-hole automatic shutdown 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 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, and pressure on the annulus between tubing and long stem 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) A tracer survey such as oxygen-activation logging;

(2) A temperature or noise log; or

(3) A casing inspection log, if required by the Director.

(d) The Director may require any other test to evaluate mechanical integrity under paragraph (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, the Director must submit a written request to the Administrator, which must set forth the proposed test and all technical data supporting its use. The Administrator must approve the request if 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.

(e) 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.

(f) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraph (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 significant movement of fluid into or between USDWs 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 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. 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 § 146.86(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;

(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting and other signs of corrosion 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) Placing coupons of the well construction materials 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; 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 or additional identified zones:

(1) The location and number of monitoring wells must be based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations and other factors;

(2) The monitoring frequency and spatial distribution of monitoring wells must be based on baseline geochemical data that has been collected under § 146.82(a)(6) and any modeling results in the area of review evaluation required by § 146.84(b);

(e) A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year throughout the duration of the geologic sequestration project;

(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 position of the pressure front by either monitoring for pressure changes in the first formation overlying the confining zone or using indirect, geophysical techniques (*e.g.*, seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools);

(h) At the Director's discretion, surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.

(1) The testing and monitoring plan must be based on potential vulnerabilities within the area of review;

(2) The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must reflect baseline data and the monitoring plan must include how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under 40 CFR 144.12;

(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(b) and to determine compliance with standards under 40 CFR 144.12; and

(j) 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 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 as specified in the permit;

(4) A description of any event which triggers a shutdown device required pursuant to § 146.88(e) and the response taken;

(5) The monthly volume of the carbon dioxide stream injected over the reporting period and project cumulatively;

(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 other test of the injection well conducted by the permittee if required by the Director; and

(3) Any well workover.

(c) Owners or operators must submit reports in an electronic format acceptable to the Director. At the discretion of the Director, other formats may be accepted.

§ 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 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 test or measure to determine bottomhole reservoir pressure;

(2) Appropriate testing methods to ensure 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 and 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 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. At the discretion of the Director, a shorter notice period may be allowed.

(d) *Plugging report.* Within 60 days after plugging or at the time of the next semi-annual report (whichever occurs earlier) the owner or operator must submit a plugging report to the Director. If the semi-annual report is due less than 15 days after completion of plugging, then the report must be submitted within 60 days after plugging. 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.)

§ 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.

(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;

(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(b);

(iii) A description of post-injection monitoring location, methods, and proposed frequency; and

(iv) A proposed schedule for submitting post-injection site care monitoring results to the Director.

(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.

(4) 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) 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 following the cessation of injection. At the Director's discretion, the monitoring will continue until the geologic sequestration project no longer poses an endangerment to USDWs.

(2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years, 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.

(3) Prior to authorization for site closure, the owner or operator must submit to the Director a demonstration, based on monitoring and other site-specific data, that the carbon dioxide plume and pressure front have stabilized and that no additional monitoring is needed to assure that the geologic sequestration project does not pose an endangerment to USDWs.

(4) If such a demonstration cannot be made (i.e., if the carbon dioxide plume and pressure front have not stabilized) after the 50-year period, the owner or operator must submit to the Director a plan to continue post-injection site care.

(c) *Notice of intent for site closure.* The owner or operator must notify the Director 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. At the discretion of the Director, a shorter notice period may be allowed.

(d) 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.

(e) Once the Director has authorized site closure, the owner or operator must submit a site closure report within 90 days that must thereafter be retained at a location designated by the Director. The report must include:

(1) Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (c) 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 as have authority over drilling activities to enable such State and local 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.

(f) 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 Regional Environmental Protection Agency 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.

(g) The owner or operator must retain for three 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 to be taken to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, closure and post-closure periods.

(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 must notify the Director and obtain his approval prior to conducting any well workover.

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