<u>Geologic Sequestration of Carbon Dioxide in Deep Saline Formations Report to Congress</u>

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BLM	Bureau of Land Management
BOEM	Bureau of Ocean Energy Management
BPM	Best practice manual
BSEE	Bureau of Safety and Environmental Enforcement
CarbonBASE	Carbon Basin Assessment and Evaluation Initiative
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CarbonSTORE	Carbon Storage Technology and Operations Research
CCS	Carbon capture and storage
CEJST	Climate and Economic Justice Screening Tool
CEQ	Council on Environmental Quality
CO_2	Carbon dioxide
CZMA	Coastal Zone Management Act
DAC	Direct air capture
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
EJ	Environmental justice
EPA	U.S. Environmental Protection Agency
FECM	Office of Fossil Energy and Carbon Management
FLPMA	Federal Land Policy and Management Act
GAO	Government Accountability Office
GHGRP	Greenhouse Gas Reporting Program
GS	Geologic Sequestration
Gt	Gigaton
IEA	International Energy Agency
IIJA	Infrastructure Investment and Jobs Act
IPCC	Intergovernmental Panel on Climate Change
MLA	Mineral Leasing Act
MPRSA	Marine Protection and the Research and Sanctuaries Act
NASM	National Academies of Sciences, Engineering, and Medicine
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NRAP	National Risk Assessment Partnership
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
R&D	Research and development
RCSP	Regional Carbon Sequestration Partnerships
RFDS	Reasonably Foreseeable Development Scenarios
SDWA	Safe Drinking Water Act
UIC	Underground Injection Control
USDW	Underground Source of drinking water
USE IT	Utilizing Significant Emissions with Innovative Technologies
USFS	U.S. Department of Agriculture Forest Service
USGS	U.S. Geological Survey

1. Introduction

Anthropogenic activity, primarily through greenhouse gas emissions, has caused global temperatures to rise at an accelerating rate. The increases in greenhouse gases in the atmosphere have been caused by ongoing, unsustainable energy consumption, changes in land use, and manufacturing and consumption practices across the globe (IPCC, 2023). The indicators of this change, including rising global temperatures, changing snow and rainfall patterns, rising sea levels, increased frequency of extreme weather events (e.g., heavy rainstorms, droughts, record-high temperatures), among others, are currently experienced in communities throughout the United States and around the world. Even the social, cultural, and natural resources that we depend upon, such as human health, infrastructure, and transportation systems, as well as energy, food, and water, are negatively affected by climate change, and the severity of these impacts will likely increase in the future if climate change mitigation actions are not taken.

To limit global warming and avert the worst effects of climate change, President Biden has set a goal of net-zero greenhouse gas emissions by 2050. There are three main ways to reduce atmospheric greenhouse gas emissions. One is to switch to alternative technologies that minimize greenhouse gas production (e.g., solar, wind, or nuclear power). The second is to capture greenhouse gases from the facilities that produce them before the gases are emitted into the air. In the second scenario, the captured carbon dioxide (CO_2) is then permanently sequestered deep beneath the earth's surface. A third method, direct air capture technology, removes CO_2 directly from the atmosphere. The CO_2 can then be stored in the subsurface.

The process of capturing carbon and storing CO_2 beneath the earth is known as Carbon Capture and Storage (CCS). Various technologies can be employed and may also play a role in decarbonizing the global power and industrial sectors (CEQ, 2021; IPCC, 2022). CCS is a developed, existing technology that can reduce CO_2 emissions to the atmosphere. A recent analysis by the International Energy Agency (IEA) projected that globally, 1.2 gigatons (Gts) of CO_2 must be captured and sequestered every year by 2030 to remain on track to reach net-zero emissions by 2050 (IEA, 2021). Responsible and widespread deployment of CCS requires a robust regulatory framework that protects underground sources of drinking water (USDWs), the environment, and human safety, facilitates public engagement, and incorporates Environmental Justice (EJ) and equity considerations, as well as incentives and policies that promote CCS.

At the direction of Congress, this report discusses the risks and benefits associated with large-scale CO_2 storage in deep saline formations, including technical risks such as CO_2 leakage and seismicity. Potential risks to project owners or operators, communities located in the vicinity, the environment, and other non-technical risks that project developers should consider when designing a geologic sequestration (GS) project are presented. How EPA's Underground Injection Control (UIC) Program manages and mitigates these risks onshore and in state waters is also discussed. The U.S. Department of the Interior (DOI) has authority to issue leases, easements, and rights-of-way and regulate carbon sequestration on the Outer Continental Shelf (OCS) and is currently developing regulations to clarify and implement its authority.

1.1 Overview of Mandates

On December 27, 2020, Congress enacted Division S, Innovation for the Environment, of the Consolidated Appropriations Act, 2021 (Pub. L. 116-260), which includes Section 102, cited as the Utilizing Significant Emissions with Innovative Technologies (USE IT) Act. In the USE IT Act, Congress directed the Administrator of the U.S. Environmental Protection Agency (EPA) to "prepare, submit to Congress, and make publicly available a report that includes— (I) a comprehensive identification of potential risks and benefits to project developers associated with increased storage of carbon dioxide captured from stationary sources in deep saline formations, using existing research; (II) recommendations for managing the potential risks identified under subclause (I), including potential risks unique to public land; and (III) recommendations for federal legislation or other policy changes to mitigate any potential risks identified under subclause (I)." This report on CO_2 storage in deep saline formations was written in response to the mandate from Congress. It is one in a series of reports on Carbon Capture, and Storage (CCS) requested by Congress as part of the Consolidated Appropriations Act, 2021. The other Congressionally mandated reports in the series are described below.

On June 30, 2021, the White House Council on Environmental Quality (CEQ) issued a report to Congress, as congressionally mandated in the USE IT Act, that identified and inventoried existing relevant federal permitting information and resources for CCS stakeholders, initiatives, and recent publications on CO_2 pipeline needs, gaps in the current regulatory framework, federal financial mechanisms available to project developers, and public engagement opportunities through existing laws (CEQ, 2021).[1] The CEQ report provides background on the role of CCS in addressing climate change and the state of technologies, policies, and permitting related to CCS. Additionally, on February 16, 2022, CEQ published interim Carbon Capture, Utilization, and Sequestration Guidance.[2] Consistent with the USE IT Act, CEQ issued the guidance to facilitate reviews associated with the deployment of CCS and to promote the efficient, orderly, and responsible development and permitting of CCS projects at an increased scale in line with the Administration's climate, economic, and public health goals (CEQ, 2022).

In Title II of the Consolidated Appropriations Act, 2021, Congress directed the EPA to submit a report "on recommendations to improve Underground Injection Control (UIC) Class VI [well] permitting procedures for commercial and research carbon sequestration projects." Class VI wells[3] are used to inject CO_2 into deep rock formations for long-term storage. The report (*Class VI Permitting Report to Congress*) (U.S. EPA, 2022) provides details on EPA's Class VI GS Rule (*Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells*) (U.S. EPA, 2010). The report to Congress describes the EPA's strategy to enhance implementation of the Class VI program. The report outlines the UIC Class VI permitting regulations, presents the EPA's permit application and review process, and describes EPA's planned program implementation, which

[1] The CEQ report *Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration* is available at https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf

[2] The draft CEQ guidance, *Carbon Capture, Utilization, and Sequestration Guidance* is available at https://www.federalregister.gov/documents/2022/02/16/2022-03205/carbon-capture-utilization-and-sequestration-guidance

[3] The UIC program consists of six classes of injection wells. Each well class is based on the type and depth of the injection activity, and the potential for that injection activity to result in endangerment of a USDW. For more information on UIC well classes, see https://www.epa.gov/uic/general-information-about-injection-wells.

includes process improvements and tools to enhance internal and external capacity. The report also describes actions that EPA had completed or was developing at the time the report was written to improve the Class VI permitting process. These items relate to enhancing and accelerating the implementation of Class VI permitting, performing periodic Class VI programmatic evaluations, and facilitating public outreach, awareness, and transparency.

Other reports on CCS requested by Congress in the Consolidated Appropriations Act, 2021 include the following:

- USE IT Act (Division S):
    - A National Academies of Sciences, Engineering and Medicine (NASEM) study[4] to assess the barriers and opportunities relating to the commercial application of CO_2 in the United States (Congress directed the Department of Energy [DOE] to lead this report and collaborate with EPA).
- Energy Act of 2020 (Division Z):
    - A NASEM study[5] to assess any barriers and opportunities relating to commercializing carbon, coal-derived carbon, and CO_2 in the United States,
    - A Government Accountability Office (GAO) report[6] on the results of a study of the successes, failures, practices, and improvements of DOE in carrying out commercial-scale carbon capture demonstration projects. GAO (2021) reviewed nine large CCS demonstration projects to identify what factors led to the success of projects or to projects being withdrawn or terminated. GAO published a report of findings in December 2021. GAO recommended that Congress consider implementing a mechanism for greater oversight and accountability of DOE CCS demonstration project funding. GAO also recommended that DOE improve its project selection and negotiation processes and more consistently administer projects,
    - A DOE report to Congress on the carbon capture technology program,
    - A DOE report to Congress that assesses the progress of all Regional Carbon Sequestration Partnerships (RCSP), identifies the remaining challenges in achieving large-scale carbon sequestration, and creates a roadmap for carbon storage,
    - A DOE report to Congress examining the opportunities for research and development (R&D) in integrating blue hydrogen technology in the industrial power sector, and how that could enhance the deployment and adoption of CCS, and
    - A DOE report to Congress on CO_2 removal needs, methods, and recommendations for advancing projects.

1.2 CO_2 Storage in Deep Saline Formations

As defined by Congress in the USE IT Act, for the purposes of this report, a *deep saline formation* (hereafter referred to as *saline formation or saline reservoir*) is a “formation of subsurface geographically extensive sedimentary rock layers saturated with waters or brines that have a high total dissolved solids content and that are below the depth where CO_2 can exist in the formation as a supercritical fluid.” Carbon dioxide is in a supercritical state when both the temperature and pressure exceed the critical temperature and pressure at which liquid and vapor CO_2 can no longer coexist. GS is

[4] https://doi.org/10.17226/26703
[5] https://doi.org/10.17226/27732
[6] https://www.gao.gov/products/gao-22-105111

the process of permanently storing captured CO_2 in suitable geologic formations beneath the earth's surface, typically at depths greater than 2,500 feet (where CO_2 will remain in a supercritical state).[7] The CO_2 can be captured from large stationary sources (such as industrial processes and electric power generation), or direct air capture (DAC) and then may be compressed to a supercritical state for transportation and injection. For GS in deep saline formations, the CO_2 stream is injected into a suitable saline reservoir. The injected supercritical CO_2 behaves like a liquid but is buoyant relative to the salty formation fluid it displaces and will tend to migrate upward.

Above the saline formation, regional confining strata that consists of impermeable rock such as shale or salt is required to prevent vertical leakage of the CO_2 from the storage formation. Saline formations, which likely contain high geologic CO_2 storage potential (IPCC, 2022), are one of five types of formations that are considered suitable for GS. The other four—depleted oil and gas reservoirs, economically un-mineable coal seams, basalts and mafic/ultramafic rocks, and organic-rich shales (NETL, 2016)—are beyond the scope of this report. Figure 1 shows the distribution of saline formations throughout the U.S.

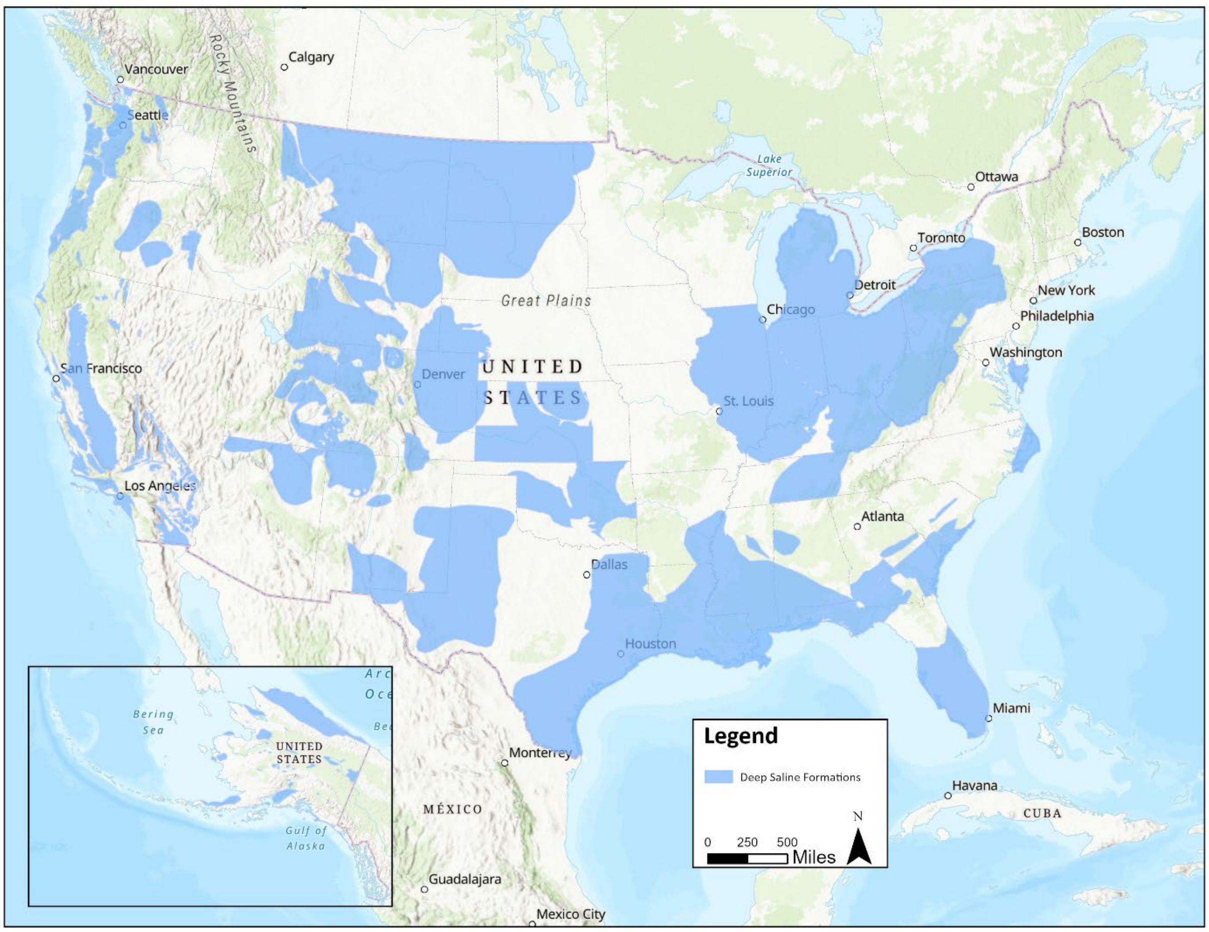

Figure 1. Distribution of deep saline formations in the US (NETL, n.d.).

7 https://www.osti.gov/biblio/1275480; https://doi.org/10.3133/ofr20101127.

EPA promulgated a regulatory framework for GS projects within the UIC program. Consistent with the Safe Drinking Water Act (SDWA) authorities, the framework was designed to address the risks to USDWs associated with long-term storage of CO_2 onshore and in State waters, which are discussed in this report. Supercritical CO_2 is relatively buoyant when injected, has subsurface mobility, is corrosive in the presence of water and in Class VI wells is injected in large volumes. The EPA's Class VI regulatory framework is designed to address the risks of CO_2 leaking out of the authorized injection zone, which may increase endangerment of a USDW. The DOI is currently developing a regulatory framework for offshore GS projects on the OCS under the Outer Continental Shelf Lands Act (OCSLA). For many years, the DOE's Office of Fossil Energy and Carbon Management (FECM) and Office of Science (SC) have been supporting research on geologic storage of CO_2. The RCSPs, launched in 2003, were designed and implemented to provide a greater understanding of storage capacity, injectivity, integrity, CO_2 migration, and sequestration of CO_2 in different geologic settings onshore and offshore. Cumulatively, the RCSPs stored more than 12 million metric tons of CO_2 and deployed a wide array of technologies with the aim to validate GS as a viable strategy for CO_2 emissions mitigation. The findings and lessons learned from the RCSPs are the foundation of DOE's best practice manuals (BPM)[8], which cover multiple topics, such as site characterization, risk management, monitoring, and public outreach. The operational aspects of these BPMs focus on onshore GS projects, but many of their recommendations could be reviewed and adapted for offshore settings.

FECM is continuing the RCSP as a technical assistance program to leverage the years of experience and expertise developed from the RCSPs. Four "Regional Initiative" projects were competitively selected in 2018 to provide technical assistance to project developers, stakeholders, and communities and to promote regional technology transfer and knowledge sharing.[9] Another 16 projects were selected in July 2023 to provide stakeholders with resources, expert teams, and information necessary to facilitate the regional deployment of large-scale geologic storage facilities and carbon management hubs.[10] In August 2024, FECM announced the selection of nine university- and industry-led Regional Initiative Technical Assistance Partnership projects to assist stakeholders and communities with the deployment of storage-based carbon management projects in specific on- and offshore geologic basins.[11]

FECM also announced their interest in launching the Carbon Storage Technology and Operations Research (CarbonSTORE) initiative[12] and the Carbon Basin Assessment and Evaluation (CarbonBASE) initiative.[13] For CarbonSTORE, FECM is interested in establishing at-scale field laboratories in different depositional settings to test and validate lower-cost next generation technologies for enhanced storage

[8] DOE's Best Practice Manuals are available at https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/best-practices-manuals

[9] https://netl.doe.gov/carbon-management/carbon-storage/regional-initiative-to-Accelerate-CCUS-deployment

[10] https://www.energy.gov/fecm/project-selections-foa-2799-regional-initiative-accelerate-carbon-management-deployment

[11] https://www.energy.gov/fecm/funding-notice-regional-initiative-technical-assistance-partnerships-ritap-advance-deployment

[12] https://www.energy.gov/fecm/request-information-carbon-storage-technology-operations-research-carbonstore

[13] https://www.energy.gov/fecm/request-information-carbon-basin-assessment-and-storage-evaluation-carbonbase

performance monitoring. For CarbonBASE[14], FECM in conjunction with DOI, held a joint workshop[15] in February 2024 to discuss the challenges and research and development needs to safely and responsibly deploy multiple GS projects within single basins. There are multiple technical and non-technical challenges. Example complexities include potential pressure plume interference and basin-wide geomechanical effects and impacts that could influence induced seismicity. In collaboration with DOI, FECM aims to collect subsurface data for basins and develop a robust set of tools for site screening and characterization and improve monitoring for basin scale storage. Basin scale assessments and models for managing subsurface storage on federal lands, both onshore and offshore will help inform relevant regulatory guidelines.

Another initiative supported by FECM is the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative that launched in 2016. The CarbonSAFE initiative consists of multi-year, multi-phase projects to support the Class VI permit application process, and construct commercial storage complexes with storage capacities of no less than 50 million metric tons of CO_2. FECM intended CarbonSAFE to build on the lessons learned from the RCSP and Regional Initiative projects and apply the latest technologies for developing and constructing commercial-scale storage complexes. The Infrastructure Investment and Jobs Act (IIJA) appropriated $2.5 billion for carbon storage validation and testing which FECM will utilize through the CarbonSAFE initiative. New projects will be selected from multiple funding opportunity announcements released periodically until 2026. Complete details on the FECM CarbonSAFE Initiative and selected projects can be found on the National Energy Technology Laboratory's (NETL's) website.[16]

To advance technology development, FECM is also engaged with U.S. national laboratories, universities, and other research institutions to investigate multiple technology areas, including monitoring tools and approaches, models and simulations, host rock interactions with CO_2, wellbore integrity and mitigation, and risk assessment and management. The primary objective of DOE's geologic storage R&D efforts is the development of an affordable and reliable suite of tools that project owners and operators can use to ensure permanent geologic carbon storage in secure and dedicated geologic formations. More information on DOE's Carbon Transport and Storage R&D Program and associated projects can be found on the NETL's website.[17]Priority areas include improving storage performance and integrity technologies.

DOE's SC provides foundational knowledge and state-of-the-art capabilities in support of CCS and has supported theoretical and experimental science related to understanding chemical and biological processes, separations, materials, and geochemistry. SC operates major X-ray, neutron, nanoscience, and high-performance computing user facilities that provide advanced synthesis, fabrication, characterization, and computational capabilities that supports CCS across the spectrum of basic and applied research.

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[14] https://www.energy.gov/fecm/articles/scaling-carbon-dioxide-storage-achieve-net-zero-future

[15] https://www.energy.gov/sites/default/files/2024-10/workshop-basin-scale-issues-for-carbon-storage.pdf

[16] There are 83 CarbonSAFE projects at the time of publication. More information on DOE's Carbon Transport and Storage Program and associated projects can be found on the National Energy Technology Laboratory's website. Details on CarbonSAFE projects are available at https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe

[17] https://netl.doe.gov/carbon-management/carbon-storage

SC's Basic Energy Sciences (BES) core program in geosciences furthers the fundamental mechanistic understanding of processes important for mineralization and GS of CO_2. In addition to the BES core programs, it invests in research through Energy Frontier Research Centers (EFRCs). For example, the EFRC "Center for Interacting Geo-processes in Mineral Carbon Storage" focuses on understanding the mineral carbonation, which can provide a foundation for the evaluation of the rate and amount of carbon that can be stored in a reservoir.

In addition, the U.S. Geological Survey (USGS) has developed a series of reports on CO_2 storage resources and assessment methodologies,[18] including the first nation-wide, comprehensive assessment of GS in sedimentary basins, which was released in 2013 (USGS, 2013). The USGS report identifies the storage of CO_2 in saline formations as an important method for mitigating climate change. The Bureau of Ocean Energy Management (BOEM) has developed a methodology for assessing carbon storage across its 26 planning areas on the continental and Alaskan Outer Continental Shelf. The study is underway and results will be available upon completion[19].

2. Geologic Sequestration Regulatory and Statutory Authorities

2.1 Authorities under the Safe Drinking Water Act

2.1.1 Federal UIC Class VI Regulations

Congress passed the Safe Drinking Water Act (SDWA) in 1974. In part, the SDWA requires the EPA to develop minimum federal requirements for UIC programs to protect public health by preventing injection wells from contaminating USDWs. The SDWA establishes requirements and provisions for the UIC program. The federal regulations for the UIC program are found in Title 40 of the Code of Federal Regulations. On December 10, 2010, EPA issued a rule that established a new UIC well class, Class VI. Class VI wells are used to inject CO_2 into deep rock formations, including deep saline aquifers, for long-term underground storage. This is referred to as GS, which is part of carbon capture and storage. This technology can be used to reduce CO_2 emissions to the atmosphere and mitigate climate change. The Class VI Rule (EPA, 2010) established minimum technical criteria to protect USDWs from the long-term subsurface storage of CO_2.

Class VI requirements consider the entire life[20] of a GS project and address:

- Geologic site characterization,

[18] USGS reports are available at https://www.usgs.gov/media/files/geologic-carbon-sequestration-assessment-results-handout and https://www.usgs.gov/faqs/how-much-carbon-dioxide-can-united-states-store-geologic-sequestration#publications

[19] https://www.boem.gov/oil-gas-energy/resource-evaluation/carbon-storage

[20] EPA considers the "life" of a GS project to span the time from submittal of an initial Class VI permit application (i.e., the pre-construction phase) through the end of the post-injection site care phase, when an owner or operator can make a non-endangerment demonstration that the project no longer poses a risk to USDWs. Other federal agencies' regulations and activities may address activities earlier or later in the project process. For example, DOI permits pre-lease exploration and conducts pre-lease planning (including resource assessments); oversees construction, operations, inspections and enforcement; and oversees decommissioning.

- Area of review (AoR) (a 3-dimensional footprint of an underground CO_2 plume and pressure front) and corrective action,
- Financial responsibility,
- Well construction,
- Injection/operation,
- Mechanical integrity,
- Testing and monitoring,
- Well plugging,
- Emergency and remedial response, and
- Post-injection site care and site closure.

2.1.2 UIC Class VI Primary Enforcement Authority (Primacy)

EPA is the permitting authority for Class VI wells in all states, territories, and Tribes that have not applied for and received Class VI primacy. For states, territories, and Tribes that have Class VI primacy, Class VI well owners or operators are subject to applicable state, territory, or Tribal regulations, which must be at least as stringent as those in the Federal Class VI Rule (U.S. EPA, 2010).

As of July 1, 2024, North Dakota, Wyoming, and Louisiana have received EPA approval for Class VI primacy and EPA has proposed approving primacy for the State of West Virginia. In addition, several states and Tribes have expressed interest in seeking EPA primacy approval for Class VI wells. The EPA is actively evaluating Class VI primacy applications from seven states. In November 2023, the EPA[21] announced $48.25 million in IIJA funding to help states and Tribes in developing and implementing UIC Class VI programs. These IIJA funds have been allocated evenly among the 25 states and Tribes that submitted letters of intent to participate in the grant program and are in the process of being awarded.

2.2 Authorities under the Clean Air Act

As directed by Congress and under the Clean Air Act authority, EPA's Greenhouse Gas Reporting Program (GHGRP) collects greenhouse gas data from large emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the United States. The Geologic Sequestration of Carbon Dioxide source category of the GHGRP (40 CFR Part 98, Subpart RR) provides an accounting framework for facilities to report amounts of CO_2 sequestered annually. Facilities develop an EPA-approved monitoring, reporting, and verification plan, report on monitoring activities, and use a mass balance approach to calculate amounts of CO_2 sequestered. The monitoring, reporting, and verification plan can be custom-tailored to accommodate a facility's site-specific circumstances. Non-confidential reported data are made available on the EPA's website. Subpart RR is complementary to and builds on EPA's UIC Class VI permit requirements.

Under Section 111 (b) and 111 (d) of the Clean Air Act, EPA, on May 9, 2024, finalized CO_2 emission limits for new, modified, and reconstructed fossil-fuel electric generating units and guidelines for reducing CO_2 emissions from existing coal-, oil-, and gas-fired steam generating units (89 FR 39798). Consistent with EPA's traditional approach to establishing pollution standards under the Clean Air Act, the final limits and emission guidelines are based on proven control technology. Emission guidelines for the longest-running existing coal units and standards for heavily utilized new gas units are based on CCS – an

[21] https://www.epa.gov/newsreleases/biden-harris-administration-announces-state-and-tribal-allocations-48-million-grant

available and cost-effective control technology that can be applied directly to power plants to significantly limit CO_2 emissions.

2.3 Geologic Sequestration on Public Land

Federally-owned public lands are typically characterized by similar geology as other parts of the US, including the presence of saline formations and overlying USDWs. Therefore, the technical risks associated with CO_2 storage (as described in Section 3) on public lands are the same as non-federal lands. In a 2009 Report to Congress: Framework for geological carbon sequestration on public land, DOI explained that currently there is no statutory authority that directly addresses the leasing of onshore public land for the long-term storage of CO_2 (U.S. DOI, 2009). However, in the report, the DOI suggests several existing authorities that could be used to authorize GS activities on onshore public land. For example, the Mineral Leasing Act (MLA) allows for multiple lessees to collectively operate under a cooperative or unit plan of development to more properly conserve oil or gas natural resources where the use is determined to be necessary or advisable in the public interest, and the Federal Land Policy and Management Act (FLPMA) authorizes the issuance of leases, permits, and easements for the use, occupancy, and development of public lands. Although determination of statutory authority will depend upon the specifics of the project, DOI considers FLPMA and its implementing regulation(s) sufficiently broad to allow for CO_2 storage on onshore public land and to provide flexibility to regulate various GS related activities, including pore space rights and leases for subsurface storage. The 2009 report states that such existing authorities may also allow for the Federal Government to lease public land for geological carbon sequestration projects at fair market value.

On June 8, 2022, the Bureau of Land Management (BLM) issued a policy memorandum regarding CO_2 storage on public lands (BLM, 2022). The memorandum provides direction for authorizing rights-of-way on public lands for site characterization, capture, transportation, injection, and permanent storage of CO_2. BLM states that the goal of the memorandum is to ensure consistent processing of right-of-way applications for GS projects across all BLM-managed lands and to provide guidance to BLM staff on how to address compliance with other applicable laws, environmental review, the term of the authorizations, rental payments, cost recovery, monitoring and long-term stewardship.

On November 3, 2023, the U.S. Forest Service (USFS) proposed to amend its special use regulations to exempt CCS from its prohibitions of authorizing exclusive and perpetual use and occupancy of National Forest System lands. (See Section 6.3.)

2.4 Offshore Geologic Sequestration

In November 2021, the Infrastructure Investment and Jobs Act amended the OCSLA to grant DOI the authority to grant a lease, easement, or right-of-way on the Outer Continental Shelf for activities that "provide for, support, or are directly related to the injection of a CO_2 stream into sub-seabed geologic formations for the purpose of long-term carbon sequestration." The Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) are in the process of developing regulations to carry out the amendments.

2.5 Other Regulatory Authorities

In addition to the EPA's Class VI UIC regulations, other environmental regulations and authorities address protecting human safety and the environment and are often applicable to GS projects. CCS involves a variety of activities that can potentially affect various environmental media. The Class VI requirements apply only to the injection of CO_2 into the subsurface and focus on the protection of USDWs. However, CCS project operators are often subject to a variety of other federal, state, and local requirements to ensure the protection of natural resources, infrastructure, people, and wildlife. These may include the National Environmental Policy Act (NEPA), which requires environmental reviews, such as environmental assessments and environmental impact statements for major federal actions, and the Coastal Zone Management Act, which requires federal actions to be consistent with enforceable policies of a state's federally-approved coastal management program. Several federal acts may require consultations regarding the effects of GS projects on fish and wildlife species and their habitats, including the Fish and Wildlife Conservation Act/Fish and Wildlife Coordination Act, the Magnuson-Stevens Fishery Conservation and Management Act, the Marine Mammal Protection Act, and Endangered Species Act.[22]

2.6 International Considerations

Sub-seabed sequestration of CO_2 is regulated internationally under the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter 1972 (London Convention) and the London Protocol, which are the principal global regimes for the protection of the marine environment from pollution caused by wastes and other matter dumped in the ocean. The London Protocol was designed to clarify and strengthen the London Convention. The United States has signed but is not a Party to (i.e., has not ratified) the 1996 London Protocol. As a signatory, the United States has an obligation to refrain, in good faith, from acts that would defeat the object and purpose of the Protocol. The United States is a Party to the London Convention, and the Marine Protection and the Research, and Sanctuaries Act (MPRSA) implements the London Convention domestically. The MPRSA applies in all ocean waters, although the Infrastructure Investment and Jobs Act specifies that a carbon dioxide stream injected for the purpose of carbon sequestration beneath the OCS is not “material” subject to the MPRSA.

3. Managing Technical Risks

EPA’s Class VI Rule (U.S. EPA, 2010) builds upon the long-standing protective framework of the UIC Program with requirements tailored to address issues unique to CO_2 injection for the purpose of GS. Of note, successful containment of CO_2 to protect USDWs also prevents the leakage of CO_2 to the surface, thereby protecting human health and the environment. A summary of the Class VI regulations that address technical risk due to GS is included in Table 1. The full list of risks and associated Class VI regulations can be found in Appendix A.

The Class VI permitting process ensures that CO_2 injection projects follow rule requirements. Owners or operators of GS projects under SDWA jurisdiction must submit a Class VI permit application for each well that they plan to operate, and their applications must contain information about the proposed formation injection zone and other geologic conditions at the proposed site; computational modeling of the AoR around the injection well; the construction of the injection well; planned operation/injection and post-injection phase testing and monitoring; financial responsibility; and emergency response planning.

[22] For additional information, see https://www.epa.gov/system/files/documents/2023-10/regulatory-and-statutory-authorities-relevant-to-carbon-capture-and-sequestration-ccs-projects.pdf.

Class VI permits are issued by the Class VI permitting authority following an extensive review of information about the GS project. Review of these application materials includes an evaluation of the project's technical risks, including an assessment of the following: whether the formation injection zone has sufficient capacity, injectivity, and appropriate geochemical characteristics to receive CO_2, whether the confining zone will provide adequate confinement of fluids under the proposed operating conditions to prevent vertical or lateral CO_2/fluid migration outside of the injection zone, and if there is a risk of an induced seismicity hazard.

Following the review of the Class VI permit application, the permitting authority develops permit conditions that address the site-specific risk of the proposed project. These conditions are, in part, guided by a set of five Class VI Project Plans that are specific to the Class VI Regulations and guidance. The five Project Plans are required by regulation and incorporated as enforceable permit conditions with which the Class VI well owner or operator must comply. They include:

- An **AoR and Corrective Action Plan** that describes computational modeling of the movement of the CO_2 plume and pressure front (based on site-specific data) to predict and identify where project operations may intersect existing faults, fractures, or wellbores. The plan also outlines efforts to identify active or abandoned wells in the AoR through data surveys and physical reconnaissance and perform corrective action on deficient wells, i.e., wells that could act as a conduit for fluid motion, as well as lays out the timeframe and conditions for AoR reevaluation (the AoR must be reevaluated at least every five years);
- A **Testing and Monitoring Plan** that describes activities that can detect well integrity issues such as corrosion monitoring, and provide early warning of lateral or vertical containment failure via subsurface water quality monitoring and CO_2 plume and pressure front tracking. The regulations[23] require continuous monitoring of internal mechanical integrity and periodic testing of external mechanical integrity to ensure that the injection well will not become a conduit for vertical fluid movement due to damage during injection operations or as a result of an induced seismic event. While not required by the Class VI Rule (U.S. EPA, 2010), where prudent to do so, many Class VI project Testing and Monitoring Plans include seismic monitoring;
- An **Injection Well Plugging Plan** that describes how the injection and monitoring wells will be plugged at the end of the project so that the wells do not become conduits for movement of CO_2 or formation fluids into USDWs;
- A **Post-injection Site Care and Site Closure Plan** that describes the testing and monitoring to be performed after cessation of injection and how the owner or operator will plug all monitoring wells and restore the site to pre-operational conditions. This post-injection monitoring must continue for at least 50 years after the cessation of injection or an alternative approved timeframe, unless an owner or operator can demonstrate, based on site specific data, modeling, and other evidence, that the geologic sequestration project no longer poses an endangerment to USDWs in advance of the 50 years/alternative timeline; and

[23] https://www.govinfo.gov/content/pkg/CFR-2014-title40-vol23/xml/CFR-2014-title40-vol23-part146.xml#seqnum146.89

- An **Emergency and Remedial Response Plan** that identifies the underground water resources potentially at risk near a Class VI project (including on federally-owned lands) and activities, equipment, and personnel to respond to unanticipated events that could endanger USDWs.

The Class VI Rule also requires owners or operators to submit information collected and generated throughout the lifetime of a Class VI project.[24] For example, during the CO_2 injection phase, owners or operators are required to submit semi-annual reports of testing and monitoring results and notifications of emergency situations, among other information, to demonstrate that the project complies with rule requirements. Site inspections are also done to verify compliance. Project plans must be reevaluated at least every five years and, as needed, amended. For additional information on the Class VI permitting process, see the Class VI Permitting Report to Congress (U.S. EPA, 2022).

Owners and operators who are developing a GS project are responsible for proposing the technologies for characterizing, operating, monitoring, and closing the site. Mature technologies from the oil and gas industry have been adapted for GS projects. To optimize cost and performance, technologies selected for a project are tailored to the geologic setting specific to the project site. DOE is supporting technology development to expand the portfolio of tools that owners and operators may employ to ensure secure storage of CO_2 and protection of USDWs.

[24]Reporting must be done in an electronic format approved by EPA regardless of whether a project is located in a state/territory/Tribe with Class VI primacy (40 CFR 146.91(e)).

Table 1. UIC Class VI Requirements and How Risks are Addressed

Class VI Requirements	How Risks are Addressed
Permit information requirements [40 CFR 146.82]	Require a thorough characterization of the geologic, hydrogeologic, geochemical, and geomechanical properties of the injection and confining zones to identify potential lateral and vertical migration pathways and faults/induced seismicity risk.
Geologic siting requirements [40 CFR 146.83]	Require permit applicants to demonstrate the presence of a geologic system that can receive the total volume of CO_2 without expanding beyond the lateral and vertical extent of the confining system or initiating/propagating fractures.
Area of Review and corrective action requirements [40 CFR 146.84]	Require computational modeling based on site-specific geologic and operational information that considers potential migration through faults and fractures to ensure that the CO_2 will remain within authorized zones. Also requires identifying/repairing wells that could be conduits for vertical fluid movement.
Financial responsibility requirements [40 CFR 146.85]	Require operators to demonstrate and maintain financial responsibility for corrective action, plugging the injection well, post-injection site care and site closure, and emergency and remedial response to ensure that these activities will be conducted without the cost being borne by the public.
Well construction requirements [40 CFR 146.86]	Ensure that the Class VI well is constructed with casing, cement, and other materials of sufficient strength that are compatible with fluids with which they may come into contact to prevent the vertical movement of fluids that can endanger USDWs.
Pre-operational testing requirements [40 CFR 146.87]	Require testing before injection may be authorized to confirm the geologic information on which the permit application is based and to verify the integrity of the injection well.
Operating requirements [40 CFR 146.88]	Limit injection pressure to prevent initiation or propagation of fractures; also require operators to maintain mechanical integrity of the injection well.
Mechanical integrity testing requirements [40 CFR 146.89]	Require continuous monitoring of internal mechanical integrity and periodic testing of external mechanical integrity to ensure that the injection well will not become a conduit for vertical fluid movement due to damage during injection operations or as a result of an induced seismicity event.
Testing and monitoring requirements [40 CFR 146.90]	Require well testing, groundwater quality monitoring, and CO_2 plume and pressure front tracking to identify potential lateral or vertical fluid movement, including movement via faults.
Reporting requirements [40 CFR 146.91]	Require operators to report all monitoring information so that it can be reviewed by the permitting authority, and to notify the permitting authority of any event that could endanger a USDW.
Well plugging requirements [40 CFR 146.92]	Require Class VI operators to plug the injection well using proper materials to ensure that it does not become a conduit for fluid movement into USDWs after injection ceases.
Post-injection site care and site closure requirements [40 CFR 146.93]	Require permittees to monitor the position of the CO_2 plume and pressure front following the cessation of injection until they can demonstrate that the GS project no longer poses an endangerment to USDWs. To close the site, operators must properly plug all monitoring wells so they will not become conduits for fluid movement.
Emergency and remedial response requirements [40 CFR 146.94]	Require operators to submit and follow an Emergency and Remedial Response Plan that describes actions during construction, operation, and post-injection site care periods to address fluid movement of the injection or formation fluids due to a vertical or lateral containment failure.

4. Technical Risks of CO_2 Storage

The concept of risk applies to the integrity of the total geologic system and infrastructure selected to contain CO_2 injected underground and infrastructure used for or impacted by CCS operations. Risk that a geosystem or infrastructure (e.g., pipelines,[25] facilities, and wells) fails to contain CO_2 (i.e., CO_2 leakage) depends on multiple components. Understanding the leakage pathways that might be encountered in a GS project and ways to mitigate leakage have been the subject of research for many years. For projects involving CO_2 injection into saline formations that are onshore and in state waters, CO_2 leakage from the intended storage target reservoir is of concern because of the potential to endanger USDWs.

UIC regulations are designed to protect USDWs and little is known about the likelihood of fresh ground water in subsurface coastal areas. Very limited groundwater quality data are available for characterization of aquifers underlying state waters. A USGS modeling study evaluated aquifers of the North Atlantic Coastal Plain from North Carolina to Long Island. The study included water quality data from 6160 onshore wells and 13 offshore cores. A handful of data points indicated brackish conditions in shallow aquifers in very close proximity to land in a few places (Pope et al., 2016). The extent and salinity of potential USDWs in state waters is largely uncertain and saltwater intrusion is an issue in most coastal areas throughout the United States. Gustafson et al., (2019) conducted two offshore electromagnetic surveys (New Jersey and Martha's Vineyard) in an effort to characterize a submarine aquifer system for paleo-hydrologic modeling. The study defined low salinity as less than 15 on the Practical Salinity Scale which is roughly equivalent to a total dissolved solids concentration of 15,000 mg/L. The EPA definition of a USDW involves a 10,000 mg/L TDS concentration. To date, USDWs have not been found on the OCS, and the existence of low salinity and potable aquifers remains uncertain.

The primary potential leakage pathways associated with GS are through wellbores and through faults or fractures in the confining strata meant to contain the CO_2 (Kelemen et al., 2019). Injection of CO_2 into subsurface saline formations could potentially induce seismicity (earthquakes), a particular concern for onshore GS sites, in a manner similar to seismicity associated with the injection of oilfield brine for disposal or enhanced oil and gas recovery (Ellsworth, 2013; Walsh & Zoback, 2015; Langenbruch & Zoback, 2016).

This section focuses on leakage and seismic risks because of their potential to negatively impact human health and the environment. Moreover, it is critical for owners and operators to address these risks prior to and during the development of a GS project. Containment failure could result in risks to the developer beyond these technical risks, including but not limited to remediation costs and harm to communities living on or near the project area; see Section 5 for additional discussion. The EPA's regulatory framework (discussed in Section 3) is designed to address the risk of USDW endangerment due to failed containment of CO_2.

4.1 Leakage Risk

Potential leakage may occur in wellbores or as a stratigraphic leak including fractures in caprock or faults reactivated by pressure buildup in the subsurface (Kelemen et al., 2019). The presence of confining, low-permeability strata (also referred to as caprock) is essential for preventing upward migration of CO_2 or briny formation fluids toward USDWs and the environment. If these strata have faults or fractures that present potential pathways for upward fluid migration, this may increase the risk of leakage and could potentially impact human and environmental resources. Class VI regulations are designed to prevent this fluid migration.

[25] While pipelines are a potential leakage pathway, they are not addressed in this report.

As CO_2 is injected into a target saline reservoir, it will typically migrate vertically and laterally within the target injection formation. Supercritical CO_2 is usually buoyant relative to the saline formation fluid. It will migrate upward within the injection zone until it is trapped or contained by a structural feature such as an overlying impermeable shale formation. Figure 2 is a schematic of a typical onshore GS project and demonstrates potential leakage pathways and mechanisms to prevent leakage.

CO_2 in the presence of water forms a weak acid, known as carbonic acid, which can corrode well materials. Thus, injection and monitoring wells completed in saline formations are potentially subject to corrosion of their casings, tubing, and packers. Class VI well casing materials must be designed for the life of the geologic sequestration project and be compatible with fluids with which the materials may be expected to come into contact (40 CFR 146.86(b)). It is the Class VI project owner's responsibility to justify the selection of appropriate well construction materials. Demonstration of suitability of well materials will be project specific and depends, among other things, on the composition of formation fluids and the CO_2 stream.

Mechanical failure of one or more components of the wellbore could lead to CO_2 leakage. Class VI project owners must ensure construction specifications are designed to minimize the risk of mechanical failure, including failure due to well construction with undetected defects. In many cases, such defects can be corrected once identified. Continuous monitoring of injection wells is required to be conducted under conditions of the permit, in order to ensure the system is operating properly and detect potential issues with wells so in the event a leakage is detected, it can be corrected before any contamination to USDWs can occur.

While project developers may consider repurposing pre-existing wells for GS of CO_2, there are technical risks that may make such a project infeasible. Not only could there be corrosion due to chemical reactions between the well materials and injected fluids, but the cumulative effects of operational stress over time may affect the well's integrity. Corrosion or deterioration of cement may be a cause of mechanical failure if older wells are converted for use as Class VI injection wells. Class VI wells must be designed to last the life of the project which will span several decades. Pre-existing wells may not be designed to meet this criterion.

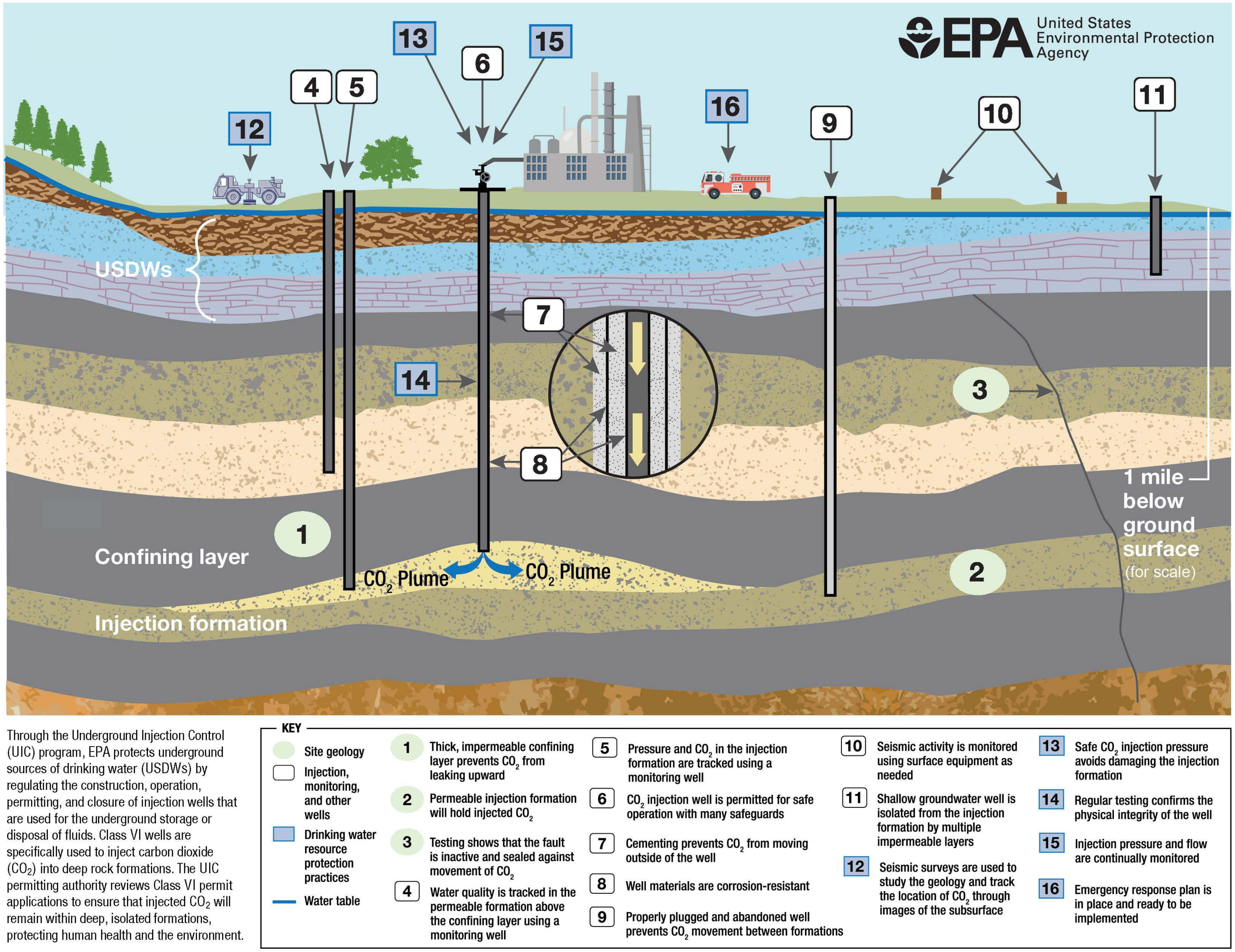

Figure 2. Schematic of a typical geologic sequestration project.

Another potential leakage pathway is along wellbores. Any existing or planned injection, production, monitoring, or stratigraphic test well (including abandoned wells) that penetrates the "confining zone" of a GS project is a potential leakage pathway to USDWs and the environment. The probability of wellbore leakage varies depending on the well type, age, and condition. For example, leakage risk may be considered much higher for abandoned and decades-old legacy wells. Legacy wells are evaluated as a part of the review process of UIC permit applications. Once the AoR is defined, artificial penetrations within the AoR boundary are identified. Once identified, the UIC permitting authority evaluates the artificial penetrations for the potential to become a conduit for fluid movement. If the UIC permitting authority identifies issues, they are addressed through the Corrective Action Plan. Figure 3 illustrates the possible leakage pathways associated with wellbores.

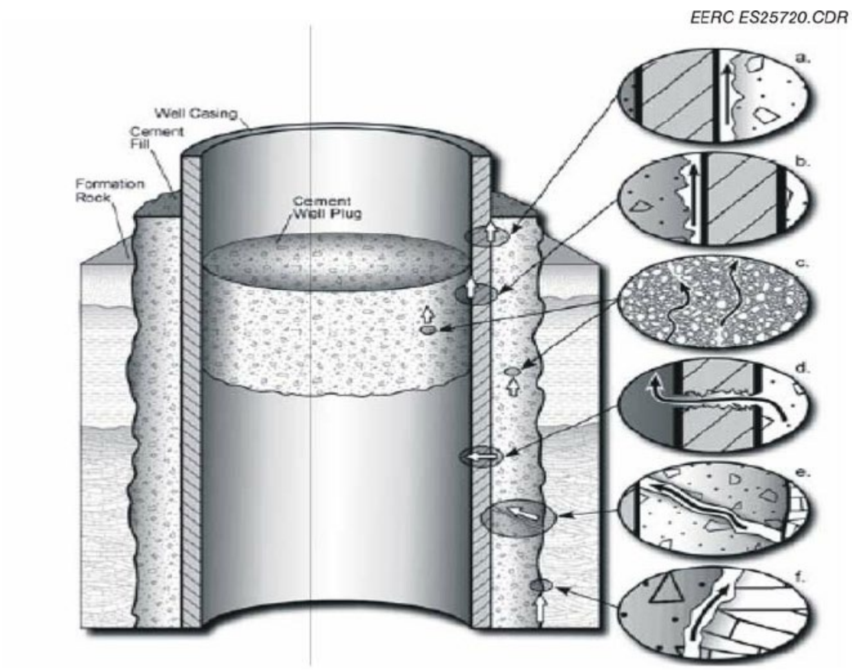

Figure 3. Potential leakage pathways (a. to f.) along an existing well. (Celia et al., 2004).

Orphaned wells that could be intersected by the CO_2 plume or pressure front are a particular concern because, in some areas of the country, their numbers and locations are unknown. USGS is working to identify and catalog these wells—the agency's documented unplugged orphaned oil and gas well dataset contains the location and status of these wells nationwide. As of 2022, the dataset includes 117,672 wells across 27 states.[26] The number of abandoned wells may be significantly higher: the

[26] https://www.usgs.gov/publications/analysis-united-states-documented-unplugged-orphaned-oil-and-gas-well-dataset.

Interstate Oil and Gas Compact Commission estimates that there may be between 300,000 and 800,000 such wells in the United States. (IOGCC, 2021).

The primary concern associated with fluid leakage from saline formations (whether from the wellbore, wellhead or through the caprock) is the potential for USDW contamination or other environmental and human impacts. Injected CO_2 streams can contain residual constituents from the capture process. Furthermore, the introduction of CO_2 into the subsurface can produce contaminants formed by means of chemical reactions between CO_2 and the native fluids or host rock (e.g., mineral dissolution). These contaminants can change the chemical composition of groundwater. Contamination of groundwater that is used as a USDW may potentially lead to exceedances of drinking water standards. Significant contamination of a USDW may render it unusable. Although USDWs have not been found in the OCS, CO_2 leakage could pose a risk to the marine environment and/or offshore workers. While Class VI injection wellheads should be inspected regularly for leaks, the likelihood of leaks from Class VI injection wellheads is extremely low.

The Federal Government is committed to the protection of USDWs and the environment. See Section 3 for a discussion of how the UIC Class VI regulations and other Federal laws and regulations help to protect human health and the environment.

4.2 Seismicity Risk

Seismicity is the occurrence or frequency of earthquakes at a given location. There are two types of seismic risk, naturally occurring seismicity and induced seismicity. Most seismicity is recognized as natural events caused by tectonic forces deep within the earth. Large earthquakes typically originate many miles deep in the basement rock, well below the sedimentary strata that would be targeted for CO_2 storage. If a CO_2 storage project is located in a seismically active area, natural seismic events may lead to vertical containment failure (discussed in Section 3.1) when faults or fractures become transmissive or rock failure around the wellbore occurs. It is also noted that the mechanical integrity of a well—even one constructed to Class VI specifications—may be compromised during a large seismic event, which can weaken cement bonds or compromise cement and casing integrity. Project developers need to select CO_2 storage sites that are not located in seismically active areas. Proper site characterization is necessary to mitigate seismicity risk.

Induced seismicity can be caused by fluid injection into the subsurface affecting subsurface stresses and contributing to induced seismic events. Most induced seismic events are very small (microseismic), are not felt at the surface, and require sensitive geophone arrays to detect them. However, some induced seismic events may be large enough to be felt at the surface. Studies of induced seismicity from wastewater disposal (e.g., Hincks et al., 2018, Grigoratos et al., 2022, Ellsworth 2013, Walsh & Zoback, 2015, Weingarten et al., 2015, Ellsworth et al., 2016) suggest that storage reservoirs, including saline formations, located directly above the basement rock run a greater risk of causing larger induced seismic events compared to storage zones closer to the Earth's surface. Changes in subsurface pressure due to injection can reduce frictional resistance on pre-existing faults in the basement rock. The increased pressure can cause sliding and may cause seismicity. This subsurface movement has the potential to create pathways for fluid to migrate upwards into a USDW.

During a GS project, induced seismic events have the highest probability of occurring during active CO_2 injection when pore pressure (pressure of the fluid in the pores of the rock) diffuses through the formation. To monitor for seismicity, a seismometer array is deployed centering on the injection well and is used to determine the locations, magnitudes, and focal mechanisms for any seismic events, in case they occur. If seismic monitoring is required, it may also include alerts from regional or national seismic monitoring networks. The goal is to manage the risk through adjustment or cessation of well operations if needed.

4.3 National Risk Assessment Partnership

One federally supported initiative that focuses exclusively on risk assessment and management is the National Risk Assessment Partnership (NRAP)[27]. Directed by NETL and collaboratively developed among five U.S. national laboratories, NRAP is a suite of open-source tools designed to assess, manage, and mitigate risks across a carbon storage project's full lifecycle.[28] Informing NRAP's scope and development is a diverse group of stakeholders including representatives from industry, academia, state agencies, federal regulatory agencies (including EPA), other federal research entities, and non-governmental organizations with informed perspectives on the challenges of the deployment of GS technologies. NRAP provides project developers and operators a variety of tools and methods to comprehensively and quantitatively assess risk (Gerstenberger et al., 2013), which is an integral part of GS project siting, operations, and closure.

Additionally, NRAP's Rules and Tools Crosswalk, developed by FECM, summarizes available computational tools that can support the permit application process. The computational tools support evaluations of induced seismicity, geomechanical and geophysical modeling, reservoir modeling, injection modeling, and AoR delineation.[29] NRAP tools can also be applied to manage risk when developing monitoring strategies to ensure containment of CO_2 and testing the integrity of the injection well to ensure no fluid migration into a USDW occurs.

5. Non-Technical Risks

Owners or operators and regulators should take non-technical risks into consideration when developing projects for injecting CO_2 into saline formations because these risks could negatively impact project development, public perception of GS, and implementation of future GS projects. This section covers risks to communities, including those with EJ concerns as well as financial risk. Risks unique to federal onshore lands and federal waters and other concerns to Class VI project developers are also discussed.

There are additional, non-technical risks for projects involving injecting CO_2 into saline formations, including the high cost and increased resource use (e.g., water) associated with some types of carbon capture, the development and use of pipeline or other infrastructure to transport CO_2 to GS sites (IPCC, 2022; Tarufelli, 2020; Tarufelli et al. 2021), and acquiring property and pore space ownership rights, where applicable. While these risks are outside the scope of this report, it is important to note that the Intergovernmental Panel on Climate Change (IPCC) report states that the economic and developmental

[27] https://netl.doe.gov/sites/default/files/rdfactsheet/R-D179_4.pdf

[28]NRAP tools and workflows are available at https://edx.netl.doe.gov/nrap/

[29] The Rules and Tools Crosswalk is available at https://www.epa.gov/system/files/documents/2022-07/RulesandToolsCrosswalkCompendiumCompToolSupportGeoCarbonStoragEnvProtectUICClassVIPermit_053122.pdf

costs of taking no action likely outweigh costs incurred through GS and other climate mitigation technologies (IPCC, 2022).

5.1. Risk to Communities

Some communities may oppose a GS project on their land or nearby to their community because community members may be concerned about a variety of issues that, while not directly addressed by federal UIC regulations, will affect their perception, and possible acceptance, of a project. For example, Class VI wells might be sited within environmental justice communities that are exposed to several sources of pollution. Concerns may also include safety and well-being of community members, levels of dust or noise during construction or operation of the project, traffic impacts, economic concerns about jobs, property values, or increased economic activity, or the ability of local first responders to address emergency events.

Communities with EJ concerns are particularly vulnerable to the greatest effects of climate change, often experiencing a disproportionate amount of pollution and other negative effects. CCS deployment is expected to reduce CO_2 and other atmospheric emissions and protect communities from increases in cumulative pollution (CEQ, 2022). It is important that CCS projects do not create additional burdens on these communities, and that direct, indirect, and cumulative effects of these projects are identified, and appropriate mitigation and avoidance measures are taken.

5.2 Financial Risk

GS projects are decades-long in duration with larger injection operations requiring several additional decades of post-injection monitoring to continue to ensure secure CO_2 storage. The long duration of these projects presents risks to project developers such as failure to meet future project cost obligations and the need for corrective action. Failure of an applicant to provide the regulator with comprehensive site characterization and data for the applicant's project may result in permitting delays and associated financial risks. Costs related to CO_2 storage in saline formations include those for well construction, operation and monitoring, site closure and well plugging and abandonment, and potential emergency response or mitigation measures to avoid such damages. Costs will vary by project and depend upon a variety of factors, such as the size of the carbon storage project and geology of the subsurface. Financial risks to the public (e.g., the risk of an owner or operator passing along project costs to the public) are mitigated through the financial responsibility provisions of the Class VI regulations at 40 CFR 146.85 (see Section 4). A summary of the Class VI regulations that mitigate financial risk to the public is included in Table 1. The full list of risks and associated Class VI regulations can be found in Appendix A.

The EPA is working to ensure timely permit reviews and address delays caused by long applicant response times to EPA requests for additional information and has established a practice across all EPA regional offices of requesting that the applicant respond to requests for additional information within 30 days. Applicants may request an extended timeframe to respond, with the understanding that an extension will impact the permitting decision timeframe. To support applicants, the EPA has provided tools and resources including a table listing the regulatory authorities that may be relevant to a carbon capture and storage project, a permit application outline, a permit application completeness checklist and, in coordination with the DOE, a rules and tools crosswalk compendium. The EPA's estimated technical review period depends on the complexity and quantity of requests for additional information needed to evaluate the application and reviewing timely responses from the applicant. See the Class VI

Permitting report (U.S. EPA, 2022) and EPA's website[30] for more information on the Class VI permit application process.

5.3 Risks Unique to Geologic Sequestration on Federal Lands and in Federal Waters

In its 2009 report *Framework for Geologic Carbon Sequestration on Public Land*, the DOI identified an estimated 5.5 percent of the onshore U.S. CO_2 storage capacity occurring beneath federally owned, public lands (U.S. DOI, 2009). Figure 4 shows the distribution of Federally-owned public lands and saline formations in the U.S.

[30] EPA's UIC Class VI website is available at https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide.

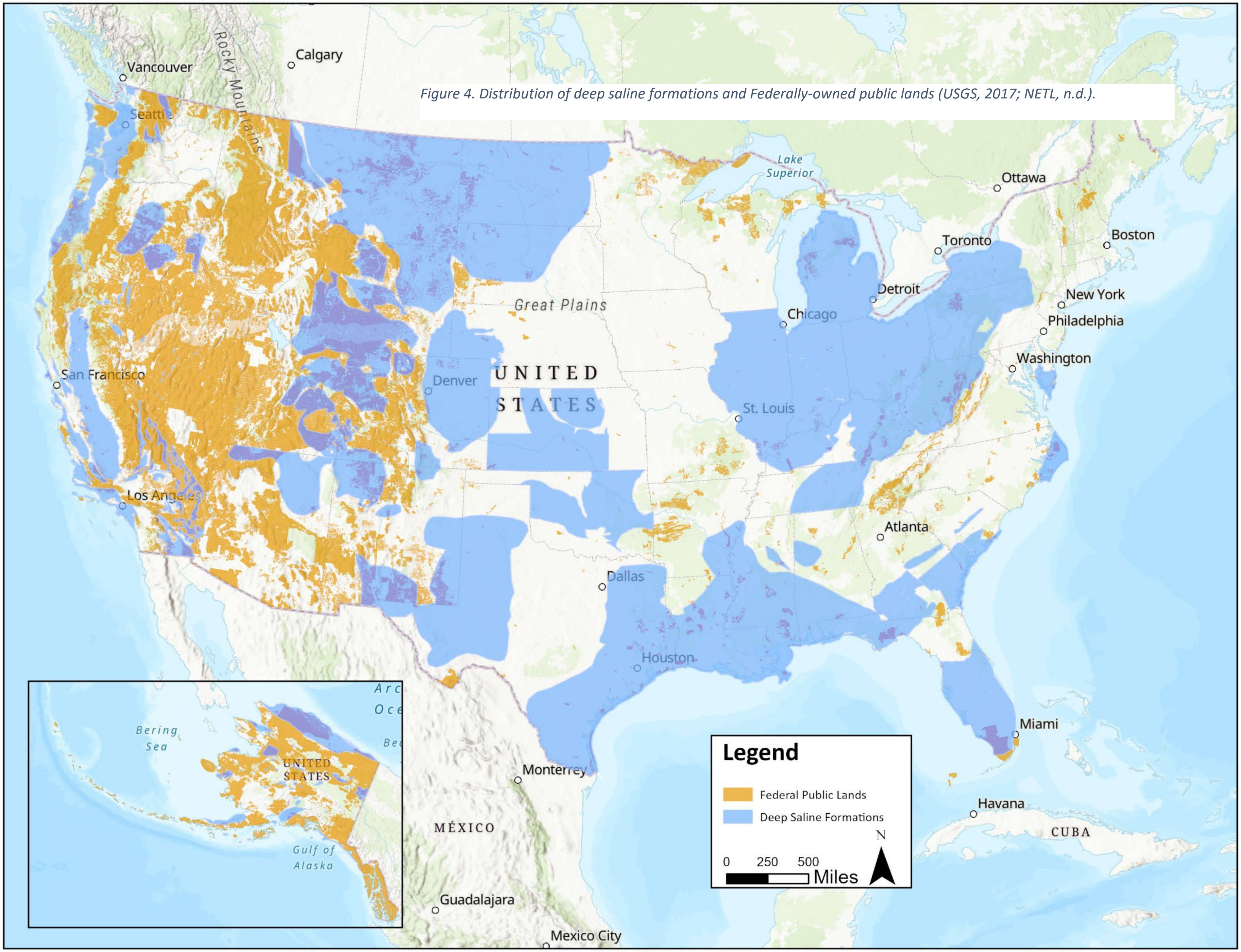

Figure 4. Distribution of deep saline formations and Federally-owned public lands (USGS, 2017; NETL, n.d.).

Onshore Class VI wells on public land must be permitted by EPA or a state/territory/tribal agency with Class VI primacy (see Section 2.1.2).The DOI report (U.S. DOI, 2009) acknowledged the potential conflicts between GS land uses and other current and/or future land uses and resources, including, but not limited to, mineral extraction, drinking water sources, and surface land use programs for grazing, community development, and recreation. Also noted by DOI was the complication of assigning long-term liability for onshore GS projects, particularly those under split estate or multiple-resource ownership of subsurface pore space and mineral rights.

The Infrastructure, Investment, and Jobs Act of 2021, gives DOI the authority to grant easements, rights-of-way, and leases for GS projects on the OCS. Long-term liability issues may be a concern for offshore GS projects. The offshore OCS CCS operations primary concern is the potential impact due to a loss of containment to offshore workers and the environment.

6. Managing Non-Technical Risks

The following section discusses how community concerns, financial risk and onshore public lands and offshore risks are managed. Appendix B summarizes the federal authorities that address non-technical risks associated with injecting CO_2 into saline formations.

6.1 Addressing Environmental Justice Concerns

The EPA is committed to carrying out its permitting process in a nondiscriminatory manner and improving the accessibility of its programs and activities to ensure meaningful access for all communities, including those that have faced environmental injustice, as well as tribal communities, persons with disabilities and persons with limited English proficiency. The EPA encourages public comment and community engagement, which informs and includes feedback from potentially impacted communities through meaningful public participation[31]. Permit applicants are strongly encouraged to begin public engagement early on in the project planning process to avoid potential delays that could arise if there is public opposition. Examples of inclusive practices are public hearings and meetings at times convenient for residents with appropriate translation services where needed and enabling face-to-face or written feedback early in the review process. To ensure the fair treatment and meaningful involvement of all people potentially affected by these projects and to integrate EJ considerations into UIC Class VI permitting decisions, EPA has developed the following tools, guidance documents, and workgroups for permitting authorities, owners and operators, and other stakeholders.

- **EJScreen** (U.S. EPA, n.d.) is an online EJ screening and mapping tool that integrates numerous demographic, socioeconomic, and environmental datasets that can be overlain on the delineated AoR. EJScreen uses demographic factors as general indicators of a community's potential susceptibility to the types of environmental exposures included in this screening tool. If the results of the screening indicate a potential EJ impact, it provides permit writers with an opportunity to consider permitting measures to mitigate the impacts of the Class VI project on those communities and enhance the public participation process to be inclusive of all potentially affected people. As part of the Class VI permit application review process, EPA regional permit writers perform an EJ analysis for each proposed project. As defined in the EJ guidance[32], the

[31] https://www.epa.gov/permits/environmental-justice-permitting

[32] https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf

five steps include the following: identify communities with potential EJ concerns, enhance public involvement, conduct appropriately scoped EJ assessments, enhance transparency throughout the permitting process, and minimize adverse effects to USDWs and the communities they may serve. The results, along with any mitigation measures that are needed and were taken, are documented into the administrative record for the Class VI permit. On February 18, 2022, EPA released an updated version of the EJScreen Tool, featuring new environmental and demographic indicators and a new Environmental Justice Index, among other updates,[33] in tandem with CEQ's public beta version of the Climate and Economic Justice Screening Tool (CEJST).[34]

- **"*Additional Tools for UIC Program Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process*"** (U.S. EPA, 2011a) is a reference guide for permitting authorities on incorporating EJ considerations into the Class VI permitting process. It describes recommended steps that can be taken throughout the permitting process. These include pre-permitting activities (e.g., working with potential permit applicants to initiate discussions with the public), evaluation of site characterization data to determine if communities with EJ concerns within the AoR may be affected, the incorporation of EJ-related considerations into the permit application review process, and implementation of an inclusive public participation process, among other activities.
- In October 2021, EPA launched the "**Environmental Justice and Civil Rights in Permitting Community of Practice**," which is led by EPA's Office of Policy and Office of General Counsel. The Community of Practice serves as a best practice repository for methods and tools to identify potential issues of equity, EJ, and civil rights in permitting, to assess vulnerabilities in communities, to share relevant literature and resources, and to make available sample language developed by EPA permitting programs. This Community of Practice develops teams, as needed, to focus on permitting issues such as analysis and data, legal issues, and communications, and to provide assistance and share information relevant to particular permitting contexts.
- "**EPA Legal Tools to Advance Environmental Justice (EJ Legal Tools)"** (EPA, 2022) is an updated and expanded compilation of legal authorities for addressing the disproportionate impact of pollution on communities with EJ concerns. This document is intended to foster dialogue between EPA and state, local, and tribal partners regarding issues of EJ and equity, as well as aid decisionmakers in incorporating EJ and equity into their decision-making processes.
- On December 9, 2022, Administrator Michael Regan sent a **letter to Governors** calling for partnership to advance the twin goals combating climate change and supporting EJ goals. A Class VI **letter to Tribal Leaders** was sent on January 11, 2023. These letters outline expectations for state and Tribal programs seeking authority to regulate the injection of CO_2 into underground deep rock formations and the Agency's aim to efficiently work together with state programs on climate and EJ.
- On August 18, 2023, EPA released an **Environmental Justice Guidance for UIC Class VI Permitting and Primacy** which serves as EPA's operating framework for identifying, analyzing, and addressing EJ concerns in the context of implementing and overseeing UIC permitting and

[33] The updated version of the EPA EJSCREEN Tool is available at https://www.epa.gov/ejscreenhttps://www.epa.gov/ejscreen

[34] The 1.0 version of the Climate and Economic Justice Screening Tool was released on Nov 22, 2022. Additional information on this tool is available at https://screeningtool.geoplatform.gov/en/#3/33.47/-97.5

primacy programs. This guidance outlines EJ considerations and expectations for UIC well owners/operators and EPA staff; communicates EPA's guidance to states, territories, and tribes that have primacy for UIC programs; and expands upon the 2011 *Additional Tools for UIC Program Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process*. Recommendations in this guidance are organized into the following five themes:

1. Identify communities with potential EJ concerns,
2. Enhance public involvement,
3. Conduct appropriately scoped EJ assessments,
4. Enhance transparency throughout the permitting process, and
5. Minimize adverse effects to USDWs and communities they serve.

- The **"Public Participation in UIC Training" module**, launched on the FedTalent website in October 2023, is part of a series of UIC training modules for federal and state UIC permitting authorities. This module discusses the regulatory framework as it relates to public participation during the UIC permitting process. It also highlights numerous ways that UIC permitters can enhance public participation to better ensure that UIC permitting employs an inclusive public participation process.

In October 2023, DOI released its Draft Environmental Justice Vision to manage natural and cultural resources in a manner that is sustainable, equitable, accessible, and inclusive of all populations.[35] It establishes five goals to implement the vision, including to: (1) institutionalize EJ within the Department and establish accountability for decisionmakers and practitioners; (2) engage early and often with communities and Tribal Nations; (3) identify, prevent, and mitigate environmental injustices, including adverse human health or environmental effects; (4) leverage funding, training, educational and professional opportunities; and (5) apply EJ principles in the Department's production, collection, and use of data, science, and research.

DOE, through its Office of Energy Justice, is working to better understand how the Department's funding and investments are distributed to overburdened and underserved communities, with the goal of these communities to be the first to benefit from clean energy solutions. DOE's Energy Justice Dashboard (BETA)[36] is a pilot data visualization tool that displays DOE-specific investments in communities experiencing disproportionately high and adverse economic, human health, climate-related, environmental, and other cumulative impacts. DOE's EJ screening tool uses the same indicators as EPA's EJScreen, combined with data generated from DOE's Low-Income Energy Affordability Data tool. These overlays create data sets that can help DOE and other entities analyze and identify areas with certain EJ parameters (i.e., Justice40 prioritized zones), and implement measures appropriately.

Other federal initiatives that aim to ensure that EJ is incorporated into Federal actions, including permitting CO_2 injection into saline formations, include the following:

- Executive Order 12898 (59 FR 7629, February 16, 1994), which directs federal agencies, to the greatest extent practicable and permitted by law, to identify and address, as appropriate,

[35] https://www.doi.gov/sites/doi.gov/files/ej-strategic-plan-draft-vision-goals-objs.pdf
[36] https://ceq.doe.gov/docs/get-involved/citizens-guide-to-nepa-2021.pdf

disproportionate, and adverse human health or environmental impacts on people of color and low-income populations.

- Executive Order 14096 (88 FR 25251, April 21, 2023) recently supplemented EO 12898 and included, among other things, consideration of "effects (including risks) and hazards. . . related to climate change and cumulative impacts of environmental and other burdens on communities with environmental justice concerns."
- Executive Order 13007 (61 FR 26771, May 24, 1996) directs agencies who manage US Federal lands to reasonably accommodate access and use of Indian sacred sites by Indian religious practitioners. They must avoid adversely affecting the physical integrity of such sites.

The informed decision-making processes under NEPA provide another opportunity for people to voice their concerns to make sure that they are considered by agencies proposing Federal actions. CEQ developed *A Citizen's Guide to the NEPA* (2007),[37] which outlines NEPA processes and provides suggestions to citizens for interacting with Federal agencies conducting NEPA reviews of a proposed action.

6.2 Managing Financial Risk

The Class VI Rule (U.S. EPA, 2010) includes financial responsibility requirements to ensure the protection of USDWs. At 40 CFR §146.85, the rule requires owners or operators of GS wells to have and maintain the necessary financial resources for: (1) performing corrective action that meets the requirements of 40 CFR §146.84; (2) injection well plugging that meets the requirements of 40 CFR §146.92, (3) post-injection site care and site closure that meets the requirements of 40 CFR §146.93, and (4) emergency and remedial response that meets the requirements of 40 CFR §146.94. The financial resources must be sufficient to address endangerment of USDWs. It is important to note that the Class VI Rule (U.S. EPA, 2010) requires the owner or operator to demonstrate non-endangerment to USDWs before plugging and abandoning a Class VI well and being released from financial responsibilities. This is to ensure that the cost of any needed corrective action or remediation efforts associated with the project is not passed on to the public after site closure. Some states authorize the transfer of long-term liability (e.g., liability of the owner or operator after it has met all UIC permit obligations including those related to site closure) to a state-run, industry funded trust fund.

The financial instrument(s) that may be used to demonstrate compliance with UIC financial responsibility requirements include, but are not limited to, trust funds, surety bonds, letters of credit, insurance, self-insurance, and escrow. Greater detail on these instruments can be found in EPA's *Underground Injection Control (UIC) Program Class VI Financial Responsibility Guidance* (U.S. EPA, 2011b).

The Class VI Rule (U.S. EPA, 2010) requires project owners and operators to have sufficient financial responsibility to cover liabilities associated with the protection and remediation of USDWs. In doing so, it also indirectly reduces impacts to other natural resources, including leakage to the atmosphere or surface damages from induced seismicity. (Note that GS projects must follow the Class VI regulations,

[37] https://ceq.doe.gov/docs/get-involved/citizens-guide-to-nepa-2021.pdf

regardless of the presence or absence of USDWs because EPA's UIC regulations apply to underground injection of all fluids that are not specifically exempt.[38])

BOEM and BSEE are currently drafting regulations for a nationwide OCS GS program considering parallel financial assurance topics.

GS projects are complex, necessitating future owners and operators to provide comprehensive site characterization and data in their application. Failure to do so may result in permitting delays and associated financial risks. The EPA UIC program continues to develop tools and processes to support future owners and operators through the Class VI permit application process. Since the Class VI Rule was finalized in 2010, EPA has released technical guidance documents and quick reference guides[39] to help permitting authorities and owners or operators. In recent years, EPA developed a suite of tools, such as the Class VI permit application outline[40] (which provides quick access to key regulatory and guidance resources relevant to each section of the application), a Class VI permit application completeness checklist[41] (which includes information that must be submitted with a Class VI permit application for it to be deemed complete by the permitting authority) and is updating the permit and project plan templates for permit writers. The EPA is developing a sample Class VI permit application and provided a training workshop for Class VI permit applicants in August 2024. These tools and the workshop provide information to prospective Class VI permit applicants on how to develop a permit application that contains all the required data and information, demonstrates that a proposed site meets the Class VI requirements, and facilitates the review. Additionally, the EPA collaborates regularly with DOE and national labs to assist with EPA technical views of Class VI applications, white papers on key technical issues, and webinar training for the regulatory community on specific topics. NRAP has produced a large number of tools and methods for assessing and managing risks of GS projects. The EPA UIC program continues to benefit significantly from the ongoing and frequent consultation with its federal partners on Class VI issues. The NRAP suite of tools enables fast quantitative risk assessment for owners and operators to make informed assessments of leakage risk, induced seismicity risk and adaptive monitoring strategies. These computational tools are valuable for expedited risk evaluation and reducing uncertainty, ultimately reducing the timeline for permitting decisions.

Other federal laws that ensure protection of the environment, for example, the Endangered Species Act, Marine Mammal Protection Act, Clean Water Act, National Historic Preservation Act, and National Environment Policy Act must also be complied with to conduct CO_2 storage projects. Compliance with requirements of these laws include environmental reviews and consultations that may result in mitigating measures and conditions of approval that are required to protect specific environmental resources. The specific permits needed will vary based on the project location (e.g., on-shore versus offshore, or on federal lands). EPA recommends that, to maximize efficiency, applicants proposing

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[38] For hydraulic fracturing exemptions, refer to P.L. 109-58 at § 322 (amending SDWA definition of underground injection at 42 U.S.C. 300h(d)); for regulatory exclusions, refer to 40 CFR § 144.1(g)(2); for expansions to the areal extent of existing Class II aquifer exemptions for Class VI wells, refer to 40 CFR § 144.7 (d).

[39] The Class VI guidance documents and quick reference guides are available at https://www.epa.gov/uic/class-vi-guidance-documentshttps://www.epa.gov/uic/class-vi-guidance-documents.

[40] The Class VI permit application outline is available at https://www.epa.gov/system/files/documents/2022-07/class_vi_permit_application_outline.pdf

[41] The Class VI permit application completeness checklist is available at https://www.epa.gov/system/files/documents/2022-07/UIC%20Class%20VI%20Completeness%20Checklist.pdf

projects on federal lands establish workgroups with appropriate stakeholders early in the permit application process. EPA issued a list of *Regulatory and Statutory Authorities Relevant to Carbon Capture and Sequestration (CCS) Projects* to help owners and operators facilitate project management.[42]

6.3 Managing Risk for Geologic Sequestration on Onshore Public Lands

With respect to risks to onshore public lands, federal land and resource planning typically considers long-term cycles and environmental impacts as part of NEPA environmental reviews for leasing land. (Note that UIC permits are not subject to the environmental impact statement provisions of section 102(2)(C) of NEPA 42 U.S.C. 4321.) Reasonably Foreseeable Development Scenarios, analogous to those developed for oil and gas projects, which are already an integral component of the resource management planning process for the BLM, may be useful when considering the long-term storage of CO_2 in saline formations and can be utilized as supporting information for planning future land uses. Such plans, in addition to analyzing environmental impacts and mitigating damage to resources, should also be made available for public comment.

To address risks to forested lands, the USFS, on November 3, 2023 proposed to amend its special use regulations to exempt CCS from its prohibitions on authorizing exclusive and perpetual use and occupancy of NFS lands. This would allow potential projects on forest land to be reviewed by the Forest Service. Proposals for underground storage of CO_2 would have to meet all other USFS screening criteria, including but not limited to consistency with the applicable land management plan, potential risks to public health or safety, and conflicts or interference with authorized uses of NFS lands or use of adjacent non-NFS lands. The "Land Uses; Special Uses; Carbon Capture and Storage Exemption Rule" has not yet been finalized.

BOEM and BSEE are currently drafting regulations for a nationwide OCS GS program addressing parallel topics to protect people and the environment. BLM and USFS are also developing regulations to manage risks associated with CO_2 storage in onshore federal lands.

6.4 Managing Risk for Offshore Geologic Sequestration

In 2018, BOEM published *Best Management Practices for CO_2 Offshore Transportation and Sub-Seabed Storage on the OCS* (Smyth & Hovorka, 2018), which discusses best management practices throughout the entire life cycle of an offshore GS project, including risk analysis and environmental monitoring. The report also identified gaps related to CO_2 operations, such as regulations regarding well abandonment. Additionally, BOEM and BSEE are developing regulations and will develop guidance to manage the risks posed by carbon dioxide sequestration in sub-seabed geologic formations and the potential effects on the OCS.

7. Key Benefits of Geologic Sequestration

Saline formations have the capacity to store large amounts of CO_2 and are present throughout the United States, they offer significant potential for co-location with CO_2 sources to potentially reduce the cost of GS and improve efficiency (i.e., by reducing CO_2 transportation costs).

[42] https://www.epa.gov/system/files/documents/2023-10/regulatory-and-statutory-authorities-relevant-to-carbon-capture-and-sequestration-ccs-projects.pdf.

The primary benefit of GS is its contribution to the world-wide effort to reduce greenhouse gas emissions to avert the more costly damages from unabated climate change. Moving toward full-scale GS can help avert the adverse effects identified by the IPCC, including increased incidences of extreme weather and climate events, ocean acidification, and degradation and destruction of ecosystems. Additional benefits include enhanced air, soil, and water quality, among others (IPCC, 2022).

The global consensus on avoiding the most severe impacts of climate change is that the world must reach net-zero greenhouse gas emissions by mid-century, and net-negative emissions shortly thereafter. The IPCC has noted that limiting temperature rise to less than 1.5 degrees Celsius above pre-industrial levels may require global geologic storage of CO_2 captured from point-sources and DAC at a scale of 350 billion metric tons to one trillion metric tons of CO_2 cumulatively by 2050.

The need for CCS as an important component of the multitude of approaches being employed to meet climate goals, domestically and globally, is highlighted in the three example analyses below:

- NASEM: To put the United States on a path to net-zero emissions by 2050, the report states that the United States should build out a national CO_2 capture, transport, and disposal network, and in the next decade, CCS should increase by a factor of ten above current levels (NASEM, 2021).
- Net Zero America Project: In the Net Zero America Project, CCS is deployed at a large scale in all scenarios, except the high electrification scenario. CCS is especially important for cement production, gas- and biomass-fired electric power generation, natural gas reforming, and biomass-derived fuels Biomass with CCS contributes significantly to hydrogen production starting in 2035. The scale of GS is 1,000 facilities capturing and sequestering 1 to 1.7 billion tons of CO_2 per year with 110,000 km of new CO_2 pipelines, a scale which is 1.3 to 2.4 times the United States' current oil production on a volume-equivalent basis (Larson et al., 2021).
- IEA: In the Net Zero Emissions Scenario, CCS and CO2 removal are estimated at 7.5 Gt and 1.9 Gt, respectively per year by 2050 (IEA, 2021).

8. Economic Incentives

When implemented according to applicable requirements and best practices, GS in saline formations can offer economic benefits both for developers and the local community in the form of employment opportunities. Several policy instruments support widespread deployment of CCS (IPCC, 2022). One example of a policy instrument is the Section 45Q tax credit, a federal financial incentive intended to promote the development and deployment of CCS technologies in the United States and reduce CO_2 emissions to the atmosphere.

The 45Q tax credit originated in 2008 through the Energy Improvement and Extension Act. On February 17, 2009, section 45Q was amended by section 1131 of Division B of the American Recovery and Reinvestment Tax Act. On December 19, 2014, section 45Q was amended by section 209(j)(1) of Division A of the Tax Increase Prevention Act of 2014. On December 27, 2020, section 45Q was amended by section 121 of the Taxpayer Certainty and Disaster Tax relief Act of 2020, enacted in Division EE of the Consolidated Appropriations Act, 2021. The 45Q tax credit "allows a credit…per metric ton of qualified carbon oxide" (IRS, 2021). The 2022 amendments to the 45Q tax credit expanded the credit up to $85 per metric ton of qualified carbon oxide that is "disposed of by the taxpayer in secure geological storage…[and] neither used by the taxpayer as a tertiary injectant in a qualified enhanced oil or natural gas recovery project nor [for the purposes of CO_2 utilization]" and up to $60 per metric ton of qualified carbon oxide that is "used by the taxpayer as a tertiary injectant in a qualified enhanced oil or natural gas recovery project and disposed of by the taxpayer in secure geological storage…[or used for the purposes of CO_2 utilization]" (IRS, 2021). The tax credit was increased to $180 per metric ton for qualified carbon oxide captured via DAC facilities and disposed of via GS and up to $130 per metric ton if the DAC CO_2 is used for enhanced oil or gas recovery or utilized (assuming the prevailing wage and apprenticeship requirements of the rule are met).

Some states also offer financial incentives, e.g., California's Low Carbon Fuel Standards Program (CARB, n.d.), which establishes carbon intensity benchmarks on fuels used in the state, where CO_2 capture associated with a refinery or ethanol facility can generate credits.

9. Recommendations

In the USE IT Act, Congress directed the Administrator of the U.S. Environmental Protection Agency (EPA) to "prepare, submit to Congress, and make publicly available a report that includes— (I) a comprehensive identification of potential risks and benefits to project developers associated with increased storage of carbon dioxide captured from stationary sources in deep saline formations, using existing research; (II) recommendations for managing the potential risks identified under subclause (I), including potential risks unique to public land; and (III) recommendations for federal legislation or other policy changes to mitigate any potential risks identified under subclause (I)." The EPA provides the following recommendations to Congress:

1. When multiple proposed Class VI projects are in close proximity to each other or are nearby existing injection wells, CO_2 plumes and pressure fronts are likely to overlap in the subsurface. The additive impact of close projects represents not only a potential increase in risk to USDWs but also a greater likelihood of induced seismicity, which could put all involved projects at risk. The ability to mitigate this risk is complicated by confidential business information (CBI) claims on well locations. Many proposed project owners are reluctant to share locational information with other applicants. However, each applicant must model and assess risk to USDW associated with their project and this cannot be properly done without locational information from potentially overlapping projects. EPA strongly supports legislative direction to facilitate addressing this issue and streamline the permitting process for such projects. For example, preventing CBI claims for Class VI well locations or requiring an information sharing process that would increase accessibility to this information.
2. Requiring the development and use of a qualified third-party review/certification for the Area of Review modeling submitted as a part of a Class VI UIC well permit application to the Class VI permitting authority would streamline the permit application review process and potentially reduce review time and program administration costs.
3. Mandating permit applicants and holders to report to EPA information on well construction materials obtained through research, demonstration studies, testing, or otherwise obtained while developing and implementing their Class VI projects, would inform the sector more broadly and mitigate overall project development risk. Shared information could assist applicants with determining the appropriateness of design and materials choice to ensure well integrity. Congress could establish such an information sharing requirement and direct EPA to

issue guidance to implement it, and to establish a clearinghouse for such information.

4. Mandating robust public participation and transparency processes for Class VI projects under development and in operation could facilitate project development. For example, potential applicants could be required to begin public outreach on injection plans prior to submitting applications to local authorities to obtain project siting permits and make monitoring data publicly available once the project is operational. This best practice can help to address community concerns up front, allowing them to be built into the permit application and streamline later stages of the permitting process, including public notice and response to comments.

5. In order to upscale the development of CCS, there is a need to support and fund research in a number of critical areas.

    a. Research to understand the impacts of CCS at the basin-scale and manage basin scale risks. This could support optimized, large-scale deployment of CCS that ensures the protection of USDWs and other important resources.

    b. Research on direct and indirect methods for tracking subsurface CO_2 movement and associated zones of pressure influence would advance the utility of these methods for testing and monitoring programs for CCS projects.

    c. Research on corrosion management for Class VI well design and materials, including methods to identify and upgrade existing wells that may be repurposed for GS of CO_2, including Class II wells, would mitigate risk of CO_2 leaks.

10. Conclusion

GS is an important component of the suite of tools to be used to reach climate goals, mitigate climate change, and promote other economic stimuli. GS is a proven technology that offers potential to remove significant volumes of CO_2 from the atmosphere and meet the Biden-Harris Administration goal of net-zero emissions by 2050. Saline formations are candidates for GS projects because they have the capacity to store large amounts of CO_2 and are widespread throughout the United States. They are present throughout the country and comprehensive basin scale modeling will enable evaluation of site suitability, storage capacity and potential cumulative impacts.

EPA's UIC regulations and guidance for the GS of CO_2 address the risks associated with large-scale CO_2 storage in deep saline formations. EPA's UIC requirements and current operational practices for Class VI wells onshore and in state waters reflect the experience and insight into what practices make GS injection wells safe and what practices cause or enhance risk. The permitting, geologic siting, construction, operation, injection and post-injection monitoring, financial responsibility, emergency, and remedial response, and plugging requirements under existing Class VI permitting regulations help protect public health and the environment by preventing contamination of USDWs. Similarly, BOEM, BSEE, BLM and USFS are each currently drafting regulations for GS activities under their respective jurisdictions.

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Appendix A. Table of Geologic Sequestration Risk and Risk Management

Technical Risk	Examples of Technical Risk	Class VI Regulations Address Technical Risks to USDWs
Lateral containment failure (i.e., causing leakage pathway or storage failure)	• Absence of or insufficiencies in lateral seals or presence of high permeability thief zones • Insufficiencies in reservoir porosity, permeability, lateral extent, or thickness that lead to lower storage capacity • CO_2 or brine migrates beyond a structural spill point • Caprock extent is less than anticipated • Subsurface chemical reactions reduce injectivity (e.g., form precipitates) and/or mobilize metals or other hazardous constituents • Injection rate is higher than anticipated	**Site Characterization Requirements**: The owner/operator must: • Perform a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed site to ensure that Class VI wells are sited in suitable locations prior to receiving authorization to construct the well **[40 CFR 146.82(a)]** and update and gather more site-specific information, including running appropriate logs, samples, and tests **[40 CFR 146.87]**, prior to receiving authorization to inject **[40 CFR 146.82 (c)]**. • Demonstrate that the proposed project site has a suitable geologic system (i.e., an injection zone of sufficient areal extent, thickness, porosity, and permeability) to receive the total anticipated volume of the CO_2 stream **[40 CFR 146.83(a)]**. • Provide information on the compatibility of the CO_2 stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s) **[40 CFR 146.82(c)(3)]**. **Area of Review Requirements**: The owner/operator must: • Delineate the Area of Review for the proposed Class VI well, which is the region surrounding the GS project where USDWs may be endangered by the injection activity, using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and is based on available site characterization, monitoring, and operational data **[40 CFR 146.84(a)].** • Predict the projected lateral (and vertical) migration of the CO_2 plume and formation fluids in the subsurface using existing site characterization, monitoring, and operational data, and computational modeling **[40 CFR 146.84(c)(1)]**. • Reevaluate the Area of Review at a minimum fixed frequency of five years **[40 CFR 146.84(e)]**.

Technical Risk	Examples of Technical Risk	Class VI Regulations Address Technical Risks to USDWs
		<u>**Injection Well Construction and Operating Requirements:**</u> The owner/operator must: • Ensure that the Class VI well(s) is/are constructed and completed to prevent the movement of fluids into or between USDWs or into any unauthorized zones **[40 CFR 146.86(a)(1)]**; with casing and cement or other materials of sufficient structural strength that are designed for the life of the GS project **[40 CFR 146.86(b)(1)]**; and with well materials that are compatible with fluids with which the materials may be expected to come into contact **[40 CFR 146.86(b)(1)]**. • Ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) **[40 CFR 146.88 (a)]**. • Maintain mechanical integrity of the injection well at all times **[40 CFR 146.88 (d)]**. <u>**Testing and Monitoring Requirements:**</u> The Class VI Rule (U.S. EPA, 2010) requires various testing and monitoring activities, including well testing, groundwater quality monitoring, and plume and pressure front tracking, to identify any risks to, and endangerment of, USDWs during the injection and post-injection phases of a Class VI project **[40 CFR 146.89, 146.90, 146.93]**. <u>**Injection Well Plugging, Post-Injection Site Care, and Site Closure Requirements:**</u> • To ensure that the well does not become a conduit for fluid movement into USDWs after injection ceases, the owner/operator must perform a final external mechanical integrity test **[40 CFR 146.92(a)]** and plug the injection well using materials that are compatible with the injectate **[40 CFR 146.92(b)(5)]**. • The owner/operator must monitor the Class VI project site following the cessation of injection (during the post-injection site care or post-injection site care phase) to show the position of the CO_2 plume and pressure front and demonstrate that USDWs are not being endangered **[40 CFR 146.93(b)]**. This monitoring must continue for at least 50 years or for the duration of the alternative timeframe approved by the Director **[40 CFR 146.93(b)(1)** and until

Technical Risk	Examples of Technical Risk	Class VI Regulations Address Technical Risks to USDWs
		the owner/operator can demonstrate that the Class VI project no longer poses an endangerment to USDWs **[40 CFR 146.93(b)(2)]**. • To close the site, the owner or operator must properly plug all monitoring wells **[40 CFR 146.93]**. **<u>Emergency and Remedial Response Requirements</u>**: The owner/operator must submit and follow an emergency and remedial response plan that describes actions to address movement of the injection or formation fluids that may endanger a USDW during construction, operation, and post-injection site care periods **[40 CFR 146.94]**.
Vertical containment failure (i.e., leakage pathway)	• Caprock failure, i.e., due to pore pressure-driven opening of faults/fractures, deformation of caprock, heterogeneities or deficiencies in caprock, or exceedance of caprock capillary entry pressure • Wellbore/wellhead leakage (i.e., failure of seals, casing, or cement) from inadequate construction or degradation/corrosion • Improperly plugged and abandoned wells [known or unknown] • Improperly sealed active wells	**<u>Site Characterization Requirements</u>**: The owner/operator must: • Perform a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed site to ensure that Class VI wells are sited in suitable locations prior to receiving authorization to construct the well **[40 CFR 146.82(a)]** and update and gather more site-specific information, including running appropriate logs, samples, and tests **[40 CFR 146.87]**, prior to receiving authorization to inject **[40 CFR 146.82 (c)]**. • Demonstrate that the proposed project site has a suitable geologic system (i.e., an injection zone of sufficient areal extent, thickness, porosity, and permeability) to receive the total anticipated volume of the CO_2 stream **[40 CFR 146.83(a)].** The Director may require operators to identify and characterize additional zones that will impede vertical fluid movement and are free of faults and fractures that may interfere with containment. **[40 CFR 146.83(b)].** • Provide information on the compatibility of the CO_2 stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s) **[40 CFR 146.82(c)(3)].** **<u>Area of Review and Corrective Action Requirements</u>**: The owner/operator must: • Delineate the Area of Review for the proposed Class VI well, which is the region surrounding the Class VI project where USDWs may be endangered by the injection activity, using computational modeling that accounts for the

Technical Risk	Examples of Technical Risk	Class VI Regulations Address Technical Risks to USDWs
		physical and chemical properties of all phases of the injected CO_2 stream and is based on available site characterization, monitoring, and operational data **[40 CFR 146.84(a)]**. • Predict, using computational modeling, the projected vertical (and lateral) migration of the CO_2 plume and formation fluids in the subsurface using existing site characterization, monitoring, and operational data **[40 CFR 146.84(c)(1)]**. • Identify and perform corrective action on all wells in the Area of Review that are determined to need corrective action **[40 CFR 146.84(d)]**. • Reevaluate the Area of Review at a minimum fixed frequency of five years and identify and perform correction on all wells in the reevaluated Area of Review that require corrective action **[40 CFR 146.84(e)]**. **<u>Injection Well Construction and Operating Requirements:</u>** The owner/operator must: • Ensure that the Class VI well(s) is/are constructed and completed to prevent the movement of fluids into or between USDWs or into any unauthorized zones **[40 CFR 146.86(a)(1)]**; with casing and cement or other materials of sufficient structural strength that are designed for the life of the Class VI project **[40 CFR 146.86(b)(1)]**; and with well materials that are compatible with fluids with which the materials may be expected to come into contact **[40 CFR 146.86(b)(1)]**. • Ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) **[40 CFR 146.88 (a)]**. • Maintain mechanical integrity of the injection well at all times **[40 CFR 146.88 (d)]**. **<u>Testing and Monitoring Requirements:</u>** The Class VI Rule (U.S. EPA, 2010) requires various testing and monitoring activities, including well testing, groundwater quality monitoring, and plume and pressure front tracking, to identify any risks to, and endangerment of, USDWs during the injection and post-injection phases of a Class VI project **[40 CFR 146.89, 146.90, 146.93]**.

Technical Risk	Examples of Technical Risk	Class VI Regulations Address Technical Risks to USDWs
		<u>**Injection Well Plugging, Post-injection Site Care, and Site Closure Requirements:**</u> • To ensure that the well does not become a conduit for fluid movement into USDWs after injection ceases, the owner/operator must perform a final external mechanical integrity test **[40 CFR 146.92(a)]** and plug the injection well using materials that are compatible with the injectate **[40 CFR 146.92(b)(5)]**. • The owner/operator must monitor the Class VI project site following the cessation of injection to show the position of the CO_2 plume and pressure front and demonstrate that USDWs are not being endangered **[40 CFR 146.93(b)]**. This monitoring must continue for at least 50 years or for the duration of the alternative timeframe approved by the Director **[40 CFR 146.93(b)(1)** and until the owner/operator can demonstrate that the Class VI project no longer poses an endangerment to USDWs **[40 CFR 146.93(b)(2)]**. • To close the site, the owner or operator must properly plug all monitoring wells **[40 CFR 146.93]**. <u>**Emergency and Remedial Response Requirements**</u>: The owner/operator must submit and follow an emergency and remedial response plan that describes actions to address movement of the injection or formation fluids that may endanger a USDW during construction, operation, and post-injection site care periods **[40 CFR 146.94]**.
Seismic events (i.e., induced and triggered seismicity)	• Reactivation of existing fault • New fault created due to brittle failure/reduction in rock strength, increased pore pressure, or thermal stress • Wellbore shearing during seismic events	<u>**Site Characterization Requirements**</u>: The owner/operator must: • Provide information on the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the Area of Review and a determination that they would not interfere with containment **[40 CFR 146.82(a)(3)(ii)]**; geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) **[40 CFR 146.82(a)(3)(iv)]**; and information on the seismic history of the area, including the presence and depths of seismic sources and a determination that the seismicity will not interfere with containment **[40 CFR 146.82(a)(3)(v)]**.

Technical Risk	Examples of Technical Risk	Class VI Regulations Address Technical Risks to USDWs
		• Demonstrate that the confining zone(s) is/are free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures **[40 CFR 146.83(a)(2)]**. **<u>Area of Review Requirements</u>**: The owner/operator must: • Predict the projected lateral and vertical migration of the CO_2 plume and formation fluids using existing site characterization, monitoring and operational data, and computational modeling that considers potential migration through faults and fractures **[40 CFR 146.84(c)(1)(iii)]**. **<u>Injection Well Construction and Operating Requirements:</u>** The owner/operator must: • Ensure that the Class VI well(s) is/are constructed and completed with casing and cement or other materials that have sufficient structural strength and are designed for the life of the Class VI project **[40 CFR 146.86(b)(1)]**. • Ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s); in no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW **[40 CFR 146.88 (a)]**. • Maintain mechanical integrity of the injection well at all times **[40 CFR 146.88 (d)]**. **<u>Testing and Monitoring Requirements:</u>** The Class VI Rule (U.S. EPA, 2010) requires various testing and monitoring activities, including well testing, groundwater quality monitoring, and plume and pressure front tracking, to identify any risks to, and endangerment of, USDWs during the injection and post-injection phases of a Class VI project **[40 CFR 146.89, 146.90, 146.93]**. **<u>Injection Well Plugging, Post-injection Site Care, and Site Closure Requirements:</u>**

Technical Risk	Examples of Technical Risk	Class VI Regulations Address Technical Risks to USDWs
		• To ensure that the well does not become a conduit for fluid movement into USDWs after injection ceases, the owner/operator must perform a final external mechanical integrity test **[40 CFR 146.92(a)]** and plug the injection well using materials that are compatible with the injectate **[40 CFR 146.92(b)(5)]**. • The owner/operator must monitor the Class VI project site following the cessation of injection to show the position of the CO_2 plume and pressure front and demonstrate that USDWs are not being endangered **[40 CFR 146.93(b)].** This monitoring must continue for at least 50 years or for the duration of the alternative timeframe approved by the Director **[40 CFR 146.93(b)(1)** and until the owner/operator can demonstrate that the Class VI project no longer poses an endangerment to USDWs **[40 CFR 146.93(b)(2)]**. • To close the site, the owner or operator must properly plug all monitoring wells **[40 CFR 146.93]**. **<u>Emergency and Remedial Response Requirements</u>**: The owner/operator must submit and follow an emergency and remedial response plan that describes actions to address movement of the injection or formation fluids that may endanger a USDW during construction, operation, and post-injection site care periods **[40 CFR 146.94]**.

Non-Technical Risk	Examples of Non-Technical Risk	Class VI Regulations Address Non-Technical Risks

Financial risk	• The long duration of GS projects presents risks that the owner or operator could change over time or be unable to meet future cost obligations of the project and any needed corrective action.
	• Risk of financial instrument failure (due to owner/operator failure, third-party failure, or cancellation/non-renewal of instrument).
		<u>**Financial Responsibility Requirements:**</u>
		• The owner/operator must demonstrate financial responsibility for corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response **[40 CFR 146.82(a)(14); 146.85(a)]**.
		• The financial responsibility instrument(s) that may be used to demonstrate compliance with financial responsibility requirements:
		  ○ Include, but are not limited to, trust funds, surety bonds, letter of credit, insurance, self-insurance, and escrow **[40 CFR 146.85(a)(2)]**; EPA recognizes that a combination of financial instruments could be used to limit the risk of instrument failure.
		  ○ Must be sufficient to address endangerment of USDWs **[40 CFR 146.85(a)(3)]**.
		  ○ Must comprise protective conditions of coverage that include, at a minimum, cancellation, renewal, and continuation provisions **[40 CFR 146.85(a)(2)]**.

Appendix B. Federal Authorities that Address Non-Technical Risk

Authority	How Risks are Addressed
Marine Protection Research and Sanctuaries Act (MPRSA)	Implements the London Convention in the United States via permitting for the transportation for the purposes of dumping and for dumping itself (disposition of material) into ocean waters and the sub-seabed thereof (with the exception of CO_2 sequestration in sub-seabed geologic formations on the OCS).
Outer Continental Shelf Lands Act (OCSLA)	Grants a lease, easement, or right-of-way on the OCS for activities that provide for, support, or are directly related to the injection of a CO_2 stream into sub-seabed geologic formations for the purpose of long-term carbon sequestration.
Mineral Leasing Act (MLA)	Addresses leasing for Federal Minerals (onshore).
Federal Land Policy and Management Act (FLPMA)	Requires development of Resource Management Plans.
National Forest Management Act	Addresses Land and Resource Management Planning for multiple uses within National Forests.
National Environmental Policy Act (NEPA)	Requires environmental reviews such as, Environmental Assessments and Environmental Impact Statements for major federal actions; also includes a public process to allow EJ communities to voice their concerns.
National Historic Preservation Act (NHPA)	Requires Tribal consultations when a project has the potential to affect historic properties on tribal lands or of significance to such tribes located off tribal land and evaluations of impacts to historic properties on or eligible for the National Register of Historic Places.
Fish and Wildlife Conservation Act/Fish and Wildlife Coordination Act	Requires consultations about non-game fish and wildlife species and their habitats.
Coastal Zone Management Act (CZMA)	Requires federal actions that are reasonably likely to affect any land or water use or natural resource of the coastal zone to be consistent with enforceable policies of a state's federally-approved coastal management program.
Magnuson-Stevens Fishery Conservation and Management Act	Requires consultations regarding adverse effects to essential fish habitat.
Marine Mammal Protection Act	Requires Incidental Take Authorization for unintentional taking of small numbers of marine mammals. Requires public review/comment, monitoring, and reporting of take to verify negligible impact.
General Military Law; Part IV: Service Supply and Property	Requires leases of non-excess military property; easements for rights-of-way for military departments; and acceptance of funds to cover administrative expenses.
Endangered Species Act	Requires consultations regarding endangered or threatened species and their habitats.
Comprehensive Environmental Response Compensation and Liability Act (CERCLA)	Addresses responding in to releases of contaminants that present an imminent and substantial danger to the environment.
Emergency Planning and Community Right to Know Act (EPCRA)	Requires reporting and emergency planning in the event of releases of listed extremely hazardous substances.
Title 41 of the Fixing America's Surface Transportation Act (FAST-41)	Voluntary program governed by the statutory eligibility criteria to coordinate interagency efforts, eliminate needless duplication, and engage federal agencies and project sponsors to foster improved communication and clarify expectations.
Consultation and Coordination with Indian Tribal Governments (E.O. 13175)	Requires regular and meaningful consultation and collaboration with Tribes.
Federal Actions to Address EJ in Minority Populations and Low-Income Populations (E.O. 12898)	Directs federal agencies, to the greatest extent practicable and permitted by law, to identify and address, as appropriate, disproportionate and adverse human health or environmental impacts on people of color and low-income populations.
Revitalizing Our Nation's Commitment to EJ for All (E.O. 14096)	Directs federal agencies to consider "effects (including risks) and hazards... related to climate change and cumulative impacts of environmental and other burdens on communities with environmental justice concerns."
Indian Sacred Sites (E.O. 13007)	Directs agencies who manage U.S. Federal lands to reasonably accommodate access and use of Indian sacred sites by Indian religious practitioners. They must avoid adversely affecting the physical integrity of such sites.

Appendix C. Annotated Bibliography

This section contains a non-exhaustive list of papers and reports related to CO_2 storage in saline formations. It is organized by type of document: geologic confinement, seismic risk, well integrity, public opinion, cost, and climate change mitigation.

Geologic Confinement

Bachu, S. (2002). Sequestration of CO_2 in Geological Media in Response to Climate Change: Road Map for Site Selection using the Transform of the Geological Space into the CO_2 Phase Space. *Energy Conversion Management, 43*(1), 87-102.

> This paper discusses the process of selecting sites for carbon sequestration. The authors conclude that site selection should be based on a suitability analysis, a proper inventory of potential sites, an assessment of the fate of the injected CO_2, and a capacity determination, together with surface criteria such as CO_2 capture and transport. The suitability analysis, both at the basin and regional scales, is based on geological, geothermal, hydrodynamic, basin maturity, economic and societal criteria. The most important factor in this suitability analysis is a site's potential for CO_2 escape and migration.

Bachu, S. (2015). Review of CO_2 Storage Efficiency in Deep Saline Aquifers. *International Journal of Greenhouse Gas Control, 40,* 188-202.

> This paper summarizes the measurement of CO_2 storage efficiency, defined as the ratio of volume of CO_2 injected into a subsurface formation by the pore space in that formation. Storage efficiency depends upon a range of factors, including geological characteristics of the storage formation, permeability of adjoining confining zones, characteristics of the CO_2 injection operation, and regulatory constraints. Additionally, engineering technologies, such as water extraction, can improve storage efficiency.

Benson, S., & Cole, D. (2008). CO_2 Sequestration in Deep Sedimentary Formations. *Elements, 4,* 325-331.

> This paper argues that a billion or more tons of CO_2 will need to be stored underground annually to achieve noticeable reductions in CO_2 emissions. Given that this total represents a 250 percent increase relative to current rates, researchers must develop a more complex understanding of the geomechanical processes of subsurface CO_2 storage, as well as create more sophisticated monitoring procedures and a robust regulatory framework.

Benson, S., Hepple, R., Apps, J., Tsang, C., & Lippmann, M. (2002). *Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geological Formations.* Berkeley, California: Lawrence Berkeley National Laboratory. (LBNL-51170).

> This study gathered and interpreted information for assessing, managing, and mitigating risks associated with deep geologic storage of wastes, to inform geologic storage of CO_2. This consists of a history and scope of the activity, risk assessment framework and methods, risk management approaches, risk mitigation and remediation methods employed, and case studies documenting responses to accidents.

Birkholzer, J., Oldenburg, C., & Zhou, Q. (2015). CO_2 Migration and Pressure Evolution in Deep Saline Aquifers. *International Journal of Greenhouse Gas Control, 40,* 203-220.

This paper discusses pressure caused by CO_2 injection into subsurface formations as a function of space and time, including the effects of confinement (boundary conditions) and highlights possible unwanted pressure impacts such as pressure-driven leakage and geomechanical damage. It also analyzes potential capacity constraints, reviews current concepts for pressure management, and closes with a discussion of the use of pressure signals for advanced monitoring.

Birkholzer, J., Zhou, Q., Rutqvist, J., Jordan, P., Zhang, K., & Tsang, C. (2006). *Research Project on CO_2 Geological Storage and Groundwater Resources: Large-Scale Hydrological Evaluation and Modeling of the Impact on Groundwater Systems*. National Energy Technology Laboratory.

This study finds that pressure perturbation and brine displacement can cause shallow-water impacts in open subsurface systems. The papers states that project managers must also consider the effects of pressure constraints in closed subsurface systems on nearby water sources. It recommends that project managers conduct site-specific models to understand the effect of subsurface CO_2 storage on local water systems.

Blondes, M., Brennan, S., Merrill, M., Buursink, M., Warwick, P., Cahan, S., Cook, T., Corum, M., Craddock, W., DeVera, C., Drake, R., II, Drew, L., Freeman, P., Lohr, C., Olea, R., Roberts-Ashby, T., Slucher, E., & Varela, B. (2013). *National Assessment of Geologic Carbon Dioxide Storage Resources—Methodology Implementation.* U.S. Geological Survey Open-File Report 2013–1055.

This report discusses minor changes to implementing the USGS National Geologic Carbon Dioxide Storage Resources Assessment. The report discusses the following: input parameter estimation, a new input parameter that addresses EPA water quality regulations, and probabilistic model calculations.

Brennan, S., Burruss, R., Merrill, M., Freeman, P., and Ruppert, L. (2010). *A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage*. U.S. Geological Survey Open-File Report 2010–1127.

This report discusses a probabilistic methodology to assess CO_2 storage capacity in different geologic strata in the United States, which accounts for geologic uncertainty. The report discusses geologic parameters, mass of CO_2 retained in pore space, and the amount of pore space where CO_2 can be stored (among other topics).

Bromhal, G., Arcentales Bastidas, D., Birkholzer, J., Cihan, A., Dempsey, D., Fathi, E., King, S., Pawar, R., Richard, T., Wainwright, H., Zhang, Y., & Guthrie, G. (2014). *Use of Science-Based Prediction to Characterize Reservoir Behavior as a Function of Injection Characteristics, Geological Variables, and Time. NRAP Technical Report Series*. Morgantown, West Virginia: U.S. Department of Energy, National Energy Technology Laboratory. NRAP-TRS-I-005-2014.

This paper reviews research about the behavior of injected CO_2 within underground formations. The researchers find that both the growth of the CO_2 plume and pressure front exhibits a characteristic evolution over time, with the rates rapidly growing during injection and then reaching a stable equilibrium. Additionally, the reservoir properties can have as large an effect on CO_2 and pressure plume size as the rate and mass of CO_2 injected.

Burruss, R., Brennan, S., Freeman, P., Merrill, M., Ruppert, L., Becker, M., Herkelrath, W., Kharaka, Y., Neuzil, C., Swanson, S., Cook, T., Klett, T., Nelson, P., & Schenk, C. (2009). *Development of A Probabilistic Assessment Methodology for Evaluation of Carbon Dioxide Storage*. U.S. Geological Survey Open-File Report 2009–1035.

This report describes a new methodology for assessing CO_2 storage in different geologic formations. The methodology treats the physical traps and saline formation as endmembers of a combined system. Inputs for probabilistic calculations, storage volumes at basin and National levels, geochemistry, and hydraulics and flow (among other topics) are discussed.

Buursink, M., Cahan, S., and Warwick, P. (2015). *National Assessment of Geologic Carbon Dioxide Storage Resources—Allocations of Assessed Areas to Federal Lands*. U.S. Geological Survey Scientific Investigations. Report 2015–5021.

This report describes a geology-based investigation of major sedimentary onshore basins in the United States and prepares an estimate of subsurface CO_2 storage capacity of technically accessible resources on a regional scale. The authors estimate that an area of about 200,000 square miles of Federal lands overlies storage resources.

Celia, M., Bachu, S., Nordbotten, J., & Bandilla, K. (2015). Status of CO_2 Storage in Deep Saline Aquifers with Emphasis on Modeling Approaches and Practical Simulations*. Water Resources Research, 51*(9), 6846-6892.

This paper identifies deep saline aquifers as having sufficient capacity to store emissions from stationary CO_2 sources for at least a century. Combining modeling studies with observations from existing injection sites enhances overall understanding of subsurface injection and will enhance the viability of CO_2 storage in deep saline aquifers.

Chadwick, A., Arts, R., Bernstone, C., May, F., Thibeau, S., & Zweigel, P. (2008). *Best Practice for the Storage of CO_2 in Saline Aquifers*. Keyworth, Nottingham: British Geological Survey.

This document gives a seven-stage template for site development, from inception to site closure, aiming to provide technical guidelines for effective and safe CO_2 storage. It includes sections on safety and risk assessment, as well as monitoring to mitigate risks. The document is based on experiences with case studies, and recommendations may vary from site to site.

Damen, K., Faaij, A., & Turkenburg, W. (2006). Health, Safety, and Environmental Risks of Underground CO_2 Storage - Overview of Mechanisms and Current Knowledge. *Climate Change, 74* (1), 289-318.

This paper gives an overview of the current knowledge and gaps in knowledge of risks associated with underground CO_2 storage. The authors conclude that, although current knowledge indicates that CO_2 can be safely stored, there is currently a general lack of knowledge about processes controlling/causing risks. They argue the principal objectives for future R&D

should be to investigate the processes that control leakage to assess the leakage rates for various geologic storages.

Espinoza, D., & Santamarina, J. (2017). CO_2 Breakthrough - Caprock Sealing Efficiency and Integrity for Carbon Geological Storage. *International Journal of Greenhouse Gas Control, 66*, 218-229.

In this article, the authors detail their study of the breakthrough pressure and CO_2 permeability through sediment plugs made of various materials and measured their subsequent volumetric deformation. They found that the breakthrough pressure was usually lower than what was predicted based on pore size. They concluded that because of unexpected CO_2 migration due to inherent spatial variability in geologic formations, sites should have redundant seal layers to mitigate leakage risks.

Goodman, A., Hakala, A., Bromhal, G., Deel, D., Rodosta, T., Failey, S., Small, M., Allen, D., Romanov, V., Fazio, J., Huerta, N., McIntyre, D., Kutchko, B., & Guthrie, G. (2011). U.S. DOE Methodology for the Development of Geologic Storage Potential for Carbon Dioxide at the National and Regional Scale. *International Journal of Greenhouse Gas Control, 5*(4), 952-965.

This paper outlines a detailed methodology for estimating CO_2 storage potential in oil and gas reservoirs, saline formations, and economically unmineable coal seams. Saline formations are assessed at the basin level. Although this methodology is intended for RCSPs and other government entities, it is generally applicable for all interested parties.

Holloway, S., Pearce, J., Ohsumi, T., & Hards, V. (2005). *A Review of Natural CO_2 Occurrences and Their Relevance to CO_2 Storage*. Keyworth, Nottingham: British Geological Survey.

This report summarizes the natural occurrence of geological CO_2 leakage. The authors conclude that to prevent leakage, CO_2 storage sites must be in stable sedimentary basins with an impermeable seal. Natural leaks of CO_2 have normally occurred in tropical crater lakes or in volcanically active areas, and CO_2 storage projects should avoid these conditions. A rigorous regulatory process is necessary to prevent CO_2 leakage.

International Energy Agency CCUS R&D Programme. (2007). *Remediation of Leakage from CO_2 Storage Reservoirs (*2007/11). Stoke Orchard, Cheltenham, United Kingdom: International Energy Agency Greenhouse Gas R&D Programme.

This report details a study conducted to assess what remediation techniques and approaches are available if leakage is identified and estimates costs of different remediation measures. The authors propose a five-part strategy for leakage prevention and remediation, concluding that the most important aspect is selecting a safe secure storage site. Additionally, they make recommendations on future work to advance the understanding and development of remediation for CCS.

International Energy Agency Greenhouse Gas R&D Programme. (2009). *Development of Storage Coefficients for Carbon Dioxide Storage in Deep Saline Formations Technical Study*. International Energy Agency Environmental Projects Ltd.

This study calculates CO_2 storage coefficients for depleted hydrocarbon reservoirs and deep saline formations. These coefficients, which measure the volume of CO_2 that can be stored in each subsurface volume, will enable researchers to more accurately measure the necessary scale for carbon storage operations to abate greenhouse gas emissions.

International Organization for Standardization. (2017). *Carbon Dioxide Capture, Transportation and Geological Storage – Geological Storage (ISO 27914:2017).* International Organization for Standardization.

This standard establishes technical standards and recommendations for geologic storage of CO_2, for the purpose of ensuring commercial, safe, long-term containment in a way that minimizes risk. These standards are for both onshore and offshore storage sites. It includes standards for the development of management systems, stakeholder engagement, risk assessment, risk management, and risk communication.

Jones, D., Beaubien, S., Blackford, J., Foekema, E., Lions, J., De Vittor, C., West, J., Widdicombe, S., Hauton, C., & Querios, A. 2015. Developments Since 2005 in Understanding Potential Environmental Impacts of CO_2 Leakage from Geological Storage. *International Journal of Greenhouse Gas Control, 40,* 350-377.

This paper reviews current research into environmental impacts of leakage from on- and off-shore CO_2 geologic storage sites. The authors conclude that impacts from fault- or well-related leakage are likely to be limited. Larger leakages from open wells or major pipeline leaks have the potential to be more harmful but are less probable and should be easier to detect and mitigate.

Kaldi, J., Daniel, R., Tenthorey, E., Michale, K., Schacht, U., Nicol, A., Underschultz, J., & Backe, G. (2013). Containment of CO_2 in CCS: Role of Caprocks and Faults. *Energy Procedia*, 5403-5410.

This paper outlines the geological characteristics of subsurface storage sites that will prevent CO_2 leaks. The caprock overlying the storage formation, and its tendency to fracture, is the most important factor that determines the extent of leakage. A caprock's seal capacity refers to the CO_2 column height that the caprock can retain before capillary forces allow the migration of the CO_2 into and possibly through the caprock.

Leetaru, H., Frailey, S., Damico, J., Mehnert, E., Birkholzer, J., Zhou, Q., & Jordan, P. 2009. Understanding CO_2 Plume Behavior and Basin-Scale Pressure Changes during Sequestration Projects through the use of Reservoir Fluid Modeling. *Energy Procedia, 1,* 1799-1806.

This paper uses reservoir fluid models to examine geological features of reservoirs that will influence CO_2 storage capacity and leakage potential. The authors find that storage sites with elevation declines, as well as storage sites with heterogenous geological features, will increase storage capacity and decrease leakage potential. Additionally, locating multiple injection sites near each other will lead to interaction effects, and further study is needed to understand how these dynamics will affect storage and leakage rates.

Leiss, W., & Krewski, D. (2019). Environmental Scan and Issue Awareness: Risk Management Challenges for CCS. *International Journal of Risk Assessment and Management, 22*(3-4), 234-253.

This paper identifies three major categories of risks facing carbon storage projects: government and industry factors, environmental risk factors, and socio-economic factors. Each of these categories contain multiple subfactors, and the researchers conclude that major institutions, like governments and industries, have proactively identified these risk factors.

Lepinski, J. (2013). *Comprehensive, Quantitative Risk Assessment of CO_2 Geologic Sequestration* OSTI ID:1126707. U.S. Department of Energy.

This report provides an overview of a project to develop and apply a process-based risk assessment model and protocol to determine quantitative risks and predict quantitative impacts for CO_2 sequestration projects. Quantitative Risk Assessments (QRAs) have been completed for three real-world sites in the US. The author concluded that their QRA tool developed is effective and that most risks associated with CO_2 sequestration can be avoided by proper site selection.

Levine, J. S., Fukai, I., Soeder, D. J., Bromhal, G., Dilmore, R. M., Guthrie, G. D., Rodosta, T., Sanguinito, S., Frailey, S., Gorecki, C., Peck, W., & Goodman, A. L. (2016). U.S. DOE NETL methodology for estimating the prospective CO2 storage resource of shales at the national and regional scale. *International Journal of Greenhouse Gas Control,* 51, C.

This report discusses the DOE's methodology for determining the amount of CO_2 that a given shale formation could hold. These shale formations typically act as reservoir seals but may be potential geologic sinks. The report also touches on requirements of prospective shale formations, notably a depth of >800m required to maintain the supercritical state of the injected CO_2.

Lewicki, J., Birkholzer, J., & Tsang, C. (2007). Natural and Industrial Analogues for Leakage of CO_2 from Storage Reservoirs: Identification of Features, Events, and Processes and Lessons Learned. *Environmental Geology, 52*(3), 457- 467.

This paper uses leakage from natural reservoirs and natural gas storage as an analogue to potential leakage of CO_2 from geologic storage sites. Among the authors' conclusions are that there is a potential for CO_2 release along unsealed fault and fracture zones; improperly constructed or abandoned wells can rapidly release large quantities of CO_2; human health risk was low due to post-leakage monitoring; and while changes in groundwater chemistry were related to CO_2 leakage, waters often remained potable. The report also discusses the importance of public education.

Manceau, J., Hatzignatiou, D., de Lary, L., Jensen, N., & Réveillère, A. (2014). Mitigation and Remediation Technologies and Practices in Case of Undesired Migration of CO_2 from A Geological Storage Unit—Current Status. *International Journal of Greenhouse Gas Control, 22,* 272-290.

This paper reviews the current state of knowledge for mitigation and remediation techniques for CO_2 geologic storage activities. It investigates how mature techniques from other fields, such as oil and gas, may be adapted for CO_2 storage. The authors also conducted a state-of-the-art review of actual practices in CO_2 storage, established from regulatory guidelines and existing projects.

Metcalfe, R., Thatcher, K., Towler, G., Paulley, A., & Eng, J. (2017). Sub-Surface Risk Assessment for the Endurance CO_2 Store of the White Rose Project, UK. *Energy Procedia, 114,* 4313-4320.

The paper details a carbon capture project in the UK and its approach to risk management, characterization, and assessment. The authors conclude that there is a high level of confidence that long-term containment would be achieved, and the system would reach long-term stability. The most important risks identified are the potential for injectivity to be affected by chemical reactions and the potential for leakage from wells.

Metz, B., O. Davidson, H. C. de Coninck, M. Loos, & L. A. Meyer (eds.). (2005). *IPCC Special Report on Carbon Dioxide Capture and Storage.* Cambridge, United Kingdom: Cambridge University Press.

This report provides a comprehensive technical summary of the process of underground carbon storage. The researchers state that observations from natural processes and modeling indicate that geological reservoirs are likely to retain over 99% of injected CO_2 over a 100-year period and are likely to retain 99% of carbon over 1,000 years. In the event of mineral carbonation, stored CO_2 would not be released into the atmosphere.

Michael, K., Golab, A., Shulakova, V., Ennis-King, J., Allinson, G., Sharma, S., & Aiken, T. (2010). Geologic Storage of CO_2 in Saline Aquifers - A Review of the Experience from Existing Storage Operations. *International Journal of Greenhouse Gas Control, 4*(4), 659-667.

The report concludes that orders-of-magnitude increases in capacity are necessary for commercial scale CO_2 storage to become a viable strategy for abating greenhouse gas emissions. New demonstration projects are needed to develop new injection strategies that combine multiple injection wells and optimize use of storage space. Storage sites should be selected that can be readily developed for commercial use.

National Academies of Sciences, Engineering, and Medicine. (2019). *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda.* Washington, DC: The National Academies Press.

This report presents a R&D plan for CO_2 removal and sequestration technologies, including bioenergy with CCS, DAC, carbon mineralization of CO_2, and sequestration of supercritical CO_2 in deep sedimentary formations.

National Energy Technology Laboratory. (2017). *Best Practices: Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects - 2017 Revised Edition* (DOE-NETL-2017/1847). Pittsburgh, Pennsylvania: U.S. Department of Energy.

This manual summarizes the best practices for monitoring, verification, and accounting (MVA) of subsurface storage of CO_2. Optical CO_2 sensors, atmospheric tracers, and eddy covariance flux measurements are common atmospheric monitoring techniques, while geochemical, surface displacement and ecosystem stress monitoring practices can detect near-surface CO_2 release from underground formations. Deploying a combination of techniques is important to minimizing the risk of leakage from these storage sites.

National Energy Technology Laboratory. (2017). *Best Practices: Operations for Geologic Storage Projects* (DOE/NETL-2017/1848). Pittsburgh, Pennsylvania: U.S. Department of Energy.

This document is a manual for best practices for geologic storage projects for future storage project developers, and CO_2 producers and transporters. The manual encompasses all facets of field operations related to planning, designing, implementing, and executing a carbon storage project. This includes monitoring to mitigate risk to drinking water sources, human health, and the environment.

National Energy Technology Laboratory. (2017). *Best Practices: Risk Management and Simulation for Geologic Storage Projects - 2017 Revised Edition* (DOE-NETL- 2017/1846). Pittsburgh, Pennsylvania: Department of Energy.

This manual presents six best practices that are intended to help project developers and other stakeholders to assess and manage geologic storage project risks. These best practices include establishing the context for risk management, identifying potential project risks, characterizing project risks, developing a risk management plan, implementing the risk management plan, and conducting periodic risk management updates.

National Energy Technology Laboratory. (2017). *Best Practices: Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects - 2017 Revised Edition* (DOE/NETL-2017/1844). Pittsburgh, Pennsylvania: U.S. Department of Energy.

This manual describes best practices for screening and selecting suitable sites for subsurface CO_2 storage. It recommends that project managers define the scope of the project and establish criteria for finding a site; screen the site using publicly available data and possibly proprietary information from energy companies, and then use technical information, such as well logs, to select appropriate sites; and produce a detailed, site-specific assessment of all potential geological, regulatory, and social issues, and then either confirm or deny the area's classification as a qualified site.

National Energy Technology Laboratory. (2019). *NETL's Analog Studies to Geologic Storage of CO_2 – Overview* OSTI ID:1615146. Pittsburgh, Pennsylvania: U.S. Department of Energy.

This paper summarizes lessons learned from natural gas storage operations that can improve the safety and effectiveness of CO_2 storage. Natural gas storage demonstrates that these projects can store large volumes of gas underground for long periods of time if best practices are implemented. Additionally, site characteristics that are ideal for natural gas storage are also frequently suitable for CO_2 storage.

National Energy Technology Laboratory. (2020). *Safe Geologic Storage of Captured Carbon Dioxide: Two Decades of DOE's Carbon Storage R&D Program in Review*. Pittsburgh, Pennsylvania: U.S. Department of Energy.

This paper reviews the safety record of the DOE's Carbon Storage R&D program. These projects have shown no adverse effects on human health and the environment, and there has been no observed movement of CO_2 outside of the intended storage reservoirs. Increased technological development and project implementation will further the public's trust in these processes.

Pawar, R., Bromhal, G., Carey, J., Foxall, W., Korre, A., Ringrose, P., Tucker, O., Watson, M., & White, J. (2015). Recent Advances in Risk Assessment and Risk Management of Geologic CO_2 Storage. *International Journal of Greenhouse Gas Control, 40,* 292-311.

> This paper outlines developments in efforts to mitigate the risks of subsurface CO_2 storage. Researchers provide four major classifications of risk: site performance risks, long-term containment risks, public perception risks, and market risks. Practitioners have gained experience managing site performance risks and have also developed a better understanding of containment and seismic activity risks. Finally, integrating communication strategies with risk management approaches has increased stakeholder confidence in these projects.

Pearce, J., Blackford, J., Beaubien, S., Foekema, E., Gemeni, V., Gwosdz, S., Jones, D., Kirk, K., Lions, J., Metcalfe, R., Moni, C., Smith, K., Steven, M., West, J., & Ziogou, F. (2014). *A Guide to Potential Impacts of Leakage from CO_2 Storage*. British Geological Survey.

> This document summarizes the conclusions and recommendations based on four years of research into potential impacts of leakage from CO_2 storage sites. The authors argue that the evidence to date indicates that the probability of leakage is low if site selection, characterization, and storage project design are done carefully. They suggest that evaluation of leakage risks be undertaken at each site, and the context of what specific impacts mean for specific storage sites is important.

Pearce, J., Jones, D., Blackford, J., Beaubien, S., Foekema, E., Gemeni, V., Kirk, K., Lions, J., Metcalfe, R., Moni, C., Smith, K., Stevens, M., West, J., & Ziogou, F. (2014). A Guide for Assessing the Potential Impacts on Ecosystems of Leakage from CO_2 Storage Sites. *Energy Procedia, 63,* 3242-3252.

> This article provides a guide to best approaches to evaluate potential impacts of leakage from CO_2 storage for onshore and offshore near-surface ecosystems and potable water, as well as guidance on appraising these impacts. The authors concluded that leakage is low risk if site selection, characterization, and storage design are conducted properly. By following this guide, an environmental monitoring plan may be developed after site selection and characterization.

Phillips, A., Cunningham, A., Gerlach, R., Hiebert, R., Hwang, C., Lomans, B., Westrich, J., Mantilla, C., Kirksey, J., Esposito, R., & Spangler, L. (2016). Fracture Sealing with Microbially-Induced Calcium Carbonate Precipitation: A Field Study. *Environmental Science and Technology, 50*(7), 4111-4117.

> This paper presents a potential solution to mitigate the risk of subsurface fluid leakage from carbon sequestration into the near wellbore environment. The authors proposed using microbially induced calcium carbonate precipitation to plug fractures and reduce permeability. They tested this method on a fractured sandstone layer and found that there was a reduction in the in-well pressure falloff, concluding that this method is a promising tool for sealing subsurface fractures to mitigate leakage risks.

Rodosta, T., Litynski, J., Plasynski, S., Spangler, L., Finley, R., Steadman, E., Ball, D., Hill, G., McPherson, B., Burton, E., & Vikara, D. (2011). U.S. Department of Energy's Regional Carbon Sequestration Partnership Initiative: Update on Validation and Development Phases. *Energy Procedia, 4,* 3457-3464.

This paper summarizes the work of DOE's RCSPs. The seven RCSP determine the appropriate technologies, regulations, and infrastructure for subsurface CO_2 storage in their areas. At the time of publication in 2011, these partnerships were nearing the completion of the validation phase of their efforts and were moving towards the Development Phase, where they would conduct large scale injection tests in the United States and Canada.

Smyth, R., & Horvorka, S. (2017). *Best Management Practices for Offshore Transportation and Sub-Seabed Geologic Storage of Carbon Dioxide* (OCS Study BOEM 2018-004). Sterling, Virginia: U.S. Department of the Interior, Bureau of Ocean Energy Management.

This report discusses best management practices for offshore transportation and sub-seabed geologic storage of CO_2, including site selection and characterization, risk analysis, project planning and execution, and monitoring.

Sokama-Neuyam, Y., Ursin, J., & Boakye, P. (2019). Experimental Investigation of the Mechanisms of Salt Precipitation during CO_2 Injection in Sandstone. *Journal of Carbon Research, 5*(4), 1-12.

This paper investigates the physical mechanisms and impact of salt precipitation for CO_2 injection into deep saline reservoirs for the purpose of improving the quantification of losses during injection. Core-flood experiments were conducted, and mechanisms of external and internal salt precipitation, the drying process, and post-precipitation effects were investigated. The authors concluded that with a better understanding of the physical mechanisms of salt precipitation during CO_2 injection, the viability of deep saline reservoirs for carbon sequestration is improved.

U.S. Department of the Interior. (2009). *Report to Congress: Framework for Geological Carbon Sequestration on Public Land.*

The BLM studied policy concerns for CCS projects on Federal lands, and identified potential concerns associated with interference of CCS with other current and future uses and resources. Some concerns raised included assignment of liability; classification of CO_2 as a waste or a resource/commodity; management of CCS projects under split estate or multiple-resource ownership; and prioritization of CCS projects when development or conservation conflicts emerge.

U.S. Environmental Protection Agency. (2008). *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide* (EPA 430-R-08-009). Washington, D.C.: U.S. Environmental Protection Agency.

This document describes geologic attributes that could influence the vulnerability of a GS system to unanticipated migration, leakage, or pressure changes; and identifies approaches to evaluate those impacts. It also identifies monitoring technologies to evaluate the performance of GS projects and potential mitigation actions in the event of leakage, unanticipated migration, or pressure changes.

Warner, T., Vikara, D., Guinan, A., Dilmore, R., Walter, R., Stribley, T., & McMillen, M. (2020). *Overview of Failure Modes and Effects Associated with CO_2 Injection and Storage Operations in Saline Formations*. National Energy Technology Laboratory.

This document describes the potential failure modes that could occur and the possible adverse effects to human health or the environment associated with injection and storage of CO_2 in onshore, saline-bearing formations. Failure modes are categorized as lateral containment failure, vertical containment failure, and induced and triggered seismicity. The report defines the potential modes of failure and possible impacts associated with CO_2 storage and summarizes known best practices to prevent, detect, or mitigate failures.

World Resources Institute. (2008). *CCS Guidelines: Guidelines for Carbon Dioxide, Transport, and Storage*. Washington, D.C.: World Resources Institute.

This report outlines guidelines for the capture, transport, and storage of CO_2. Guidelines related to storage include monitoring and verification, risk assessment, financial responsibility, site selection, injection operations, and site closure.

Zhou, Q., Birkholzer, J., Tsang, C.-F., & Rutqvist, J. (2008). *A Method for Quick Assessment of CO_2 Storage Capacity in Closed and Semi-Closed Saline Formations* (LBNL-63820). Lawrence Berkeley National Laboratory.

High rates of CO_2 injection into closed and semi-closed saline aquifer systems can diminish their storage capacity due to pressure-induced geomechanical damage. This paper details a quick-assessment methodology for estimating these aquifers storage capacity. Understanding this capacity allows project managers to avoid damaging these systems and prevent CO_2 leakage.

Seismic Risk

International Energy Agency Greenhouse Gas R&D Programme. (2013). *Induced Seismicity and its Implications for CO_2 Storage Risk*. International Energy Agency Environmental Projects Ltd.

This report details how the risks from induced seismicity at CCS sites can be mitigated with a risk management program. They suggest that the guidelines already established for enhanced geothermal systems can provide a starting point for a management strategy of induced seismicity at CCS sites. For forecasting seismicity, the authors found that statistical models show the best promise. However, physical models are being developed for future use.

Sminchak, J., Gupta, N., & Bergman, P. (2002). Issues Related to Seismic Activity Induced by the Injection of CO_2 in Deep Saline Aquifers. *Journal of Energy & Environmental Research*, 2, 32-46.

This paper finds that managers can use proper siting, installation, operation, and management procedures to avoid causing seismic activity associated with CO_2 storage operations. Induced seismic activity usually occurs along previously faulted rocks and may be investigated by analyzing the stress conditions at depth. Seismic events are unlikely to occur due to injection in porous rocks unless very high injection pressures cause hydraulic fracturing. Given these factors, regions in the central, midwestern, and southeastern United States appear best suited for deep well injection.

Vilarrasa, V., Carrera, J., Olivella, S., Rutqvist, J., & Laloui, L. (2019). Induced Seismicity in Geologic Carbon Storage. *Solid Earth, 10,* 871-892.

This paper reviews triggering mechanisms of induced seismic activity and proposes a methodology based on proper site characterization, monitoring, and pressure management to minimize induced seismicity. The authors conclude that a detailed site characterization, monitoring, and pressure management should minimize the risk of inducing perceivable earthquakes.

Zoback, M., & Gorelick, S. (2012). Earthquake Triggering and Large-Scale Geologic Storage of Carbon Dioxide. *Proceedings of the National Academy of Sciences, 109*(26), 10164-10168.

In this paper, the authors argue that the risk of earthquakes triggered by CO_2 sequestration is high and that this risk will result in leakage of CO_2, thus negating any potential positive environmental impact of carbon sequestration. They conclude that for CO_2 sequestration to be a viable technology, siting must be done to avoid geologic formations that are brittle and prone to fracturing from injection stresses. The authors discuss the availability of appropriate sites, and some challenges in using them.

Well Integrity

Hammack, R., Veloski, G., Hodges, D., & White, C. (2016). *Methods for Finding Legacy Wells in Large Areas* OSTI ID: 1330218. Pittsburgh, Pennsylvania: U.S. Department of Energy.

In this report, the authors provide context for why locating and plugging abandoned wells is important to mitigating risk for carbon storage projects. They used well locating methods using helicopter or ground vehicle-mounted magnetometers and mobile methane detection. The methods were evaluated at an abandoned oilfield where they found that the helicopter magnetic survey was able to find 93% of visible wells, concluding that helicopter magnetic surveys are a reliable method for well finding over a larger area.

Lackey, G., Vasylkivska, V., Huerta, N., King, S., & Dilmore, R. (2019). Managing Well Leakage Risks at A Geologic Carbon Storage Site with Many Wells. *International Journal of Greenhouse Gas Control, 88,* 182-194.

This paper uses an Integrated Assessment Model to estimate well leakage risks and test various leak management strategies at a heavily drilled geologic carbon storage site. The researchers find that predicted leakage from the sites is minimal, and accurate prior information about leakage at the wells reduced leakage risks. The importance of post-injection site care length is not clear, given that there was a negligible effect on CO_2 leakage risk, but a large impact on brine leakage rate.

Public Opinion of CO_2 Storage Projects

Ashworth, P., Bradbury, J., Feenstra, C., Greenberg, S., Hund, G., Mikunda, T., & Wade, S. 2010. *Communication Project Planning and Management for Carbon Capture and Storage Project: An International Comparison*. CSIRO.

> This report presents case studies in public communication and outreach for CCS projects in The Netherlands, United States, and Australia, and shows how a project's ability to adapt to its social context is key for success. The authors conclude that communication must be integrated as a project component from the beginning.

Ashworth, P., Wade, S., Reiner, D., & Liang, X. (2015). Developments in Public Communications on CCS. *International Journal of Greenhouse Gas Control, 40,* 449-458.

> This paper gives an overview of the past ten years of social science research related to CCS and finds that there are two essential pre-conditions for CCS to be seen as credible: the perception that global climate change is a serious problem, and there is a need for large CO_2 emissions reduction. The authors also summarize continuing or emerging areas of concern.

Krause, R., Carley, S., Warren, D., Rupp, J., & Graham, J. (2014). Not In (or Under) My Backyard: Geographic Proximity and Public Acceptance of Carbon Capture and Storage Facilities. *Risk analysis: an official publication of the Society for Risk Analysis, 34*(3), 529-540.

> This paper analyzes survey data collected from the public in Indiana to assess their acceptance of CCS technology and attitudes toward a potential project in their area. The authors highlight the most important factors in people's attitudes and detail insights about perceived risks associated with CCS and public acceptance at national and local levels.

Mander, S., Polson, D., Roberts, T., & Curtis, A. (2011). Risk from CO_2 Storage in Saline Aquifers: A Comparison of Lay and Expert Perceptions of Risk. *Energy Procedia, 4,* 6360-6367.

> The authors address and compare the perceptions of risk of laypersons and experts, based on two case studies. They concluded that there are some risk factors that are important to both lay people and experts such as financial, leakage, and uncertainty. Lay people ranked potential for environmental damage, and leakage as the highest risk, while experts ranked risk associated with CO2 storage and general uncertainty as the highest risk. Through the process of learning about CCS technology, the public trusted the experts more and were more willing to accept uncertainty.

National Energy Technology Laboratory. (2017). *Best Practices: Public Outreach and Education for Geologic Storage Projects* DOE/NETL-2017/1845. Pittsburgh, Pennsylvania: U.S. Department of Energy.

> This document provides context for why public outreach and education is needed for geologic storage projects and outlines 11 best practices for doing so. It also provides case studies of past public outreach and education initiatives.

National Petroleum Council. (2019). *Meeting the Dual Challenge: A Roadmap to At- Scale Deployment of Carbon Capture, Use, and Storage. Chapter Four - Building Stakeholder Confidence*. Washington, D.C.: National Petroleum Council Report.

This paper outlines ways to mitigate the risk of CCS projects failing because of stakeholder rejection. They define different types of stakeholders, including project, public, and private, and provide examples of ways different types of stakeholders can be successfully engaged. Finally, they provide methods for improving public acceptance by conducting meaningful community engagement, clarifying messaging, demonstrating societal benefits, and funding engagement research and education opportunities. The paper also reviews the supply chains of subsurface carbon storage in the United States and examines the economic challenges and opportunities facing the industry.

Tcvetkov, P., Cherepovitsyn, A., & Fedoseev, S. (2019). Public Perception of Carbon Capture and Storage: A State-of-the-Art Overview. *Heliyon, 5,* 1-28.

This review article provides an overview of the current public perception of CCS, outlines nine key aspects of forming public perception, and highlights key knowledge gaps in CCS public perception research. The authors concluded that it is necessary to improve stakeholder interactions over the course of the entire project by overcoming the key barriers outlined in this report for a project to be successful.

Terwel, B., Daamen, D., & ter Mors, E. (2013). Not in My Back Yard (NIMBY) Sentiments and the Structure of Initial Local Attitudes Toward CO_2 Storage Plans. *Energy Procedia, 37,* 7462-7563.

The authors present their research findings about the question of how much "NIMBY sentiments" affect the level of public opposition to a CO_2 storage project. They found that overall attitudes towards CO_2 storage projects were more important than NIMBY sentiment. Furthermore, attitudes are affected by the public's level of trust in government. The authors concluded that while NIMBY attitudes may play a role in public acceptance or rejection, the initial reactions are not dominated by it.

Terwel, B., Koudenburg, F., & ter Mors, E. (2014). Public Responses to Community Compensation: The Importance of Prior Consultations with Local Residents. *Journal of Community & Applied Social Psychology, 24*(6), 479-490.

This paper outlines a study undertaken to compensate community members bearing burdens associated with implementing a company's industrial project. The compensation was either public goods compensation or monetary. The authors found that the company was perceived as more concerned with public interest when they offered public goods compensation instead of monetary. They concluded that this study demonstrated the importance of consultations with local residents when deciding on compensation measures.

Terwel, B., ter Mors, E., & Daamen, D. (2012). It's Not Only About Safety: Beliefs and Attitudes of 811 Local Residents Regarding A CCS Project in Barendrecht. *International Journal of Greenhouse Gas Control*, *9,* 41-51.

This paper reports the results of a public opinion survey regarding a proposed CCS project in The Netherlands. The results showed that the public was very negative about the project and felt it was an important issue. A combination of concerns about property values and safety, and attitudes towards the decision-making process both contributed to public opinion. The public felt that the government and project developer had an unfair role in the decision-making process, as opposed to local government which was more trusted. The authors used this study to make conclusions about implications and challenges for future CCS projects.

U.S. Environmental Protection Agency. (2011). *UIC Quick Reference Guide: Additional Considerations for UIC Program Directors on the Public Participation Requirements for Class VI Injection Wells* (EPA 816-R-11-001).

This document presents a series of steps for achieving the public participation requirements of the Class VI Rule and educating the public about GS technology.

U.S. Environmental Protection Agency. (2011). *UIC Quick Reference Guide - Additional Tools for UIC Program Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process* (EPA 816-R-11-002).

This guide describes seven steps for performing an EJ analysis, including mapping tools that are available to identify disadvantaged communities within the AoR of a Class VI project. It also describes potential mitigation measures, including additional permit conditions and enhanced public outreach.

CO_2 Storage Project Costs

Grant, T., & Morgan, D. (2017). *FE/NETL CO_2 Saline Storage Cost Model: User's Manual* (DOE/NETL-2017/1582). Pittsburgh, Pennsylvania: U.S. Department of Energy, National Energy Technology Laboratory.

This manual provides information on the FE/NETL CO_2 Saline Storage Cost Model, an Excel-based tool developed by the NETL, that estimates the price of storing CO_2 in deep saline formations. This manual discusses potential outputs for the model, how outputs are calculated, and how inputs are related to outputs.

National Energy Technology Laboratory. (2019). *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity* (NETL-PUB-22638). U.S. Department of Energy.

This report reviews the cost and performance of fossil fuel-based generation technologies. Costs for CO_2 transport and storage in saline formations are described in Section 2.7.3.

Vidas, H., Hugman, B., Chikkatur, A., & Venkatesh, B. (2012). *Analysis of the Costs and Benefits of CO_2 Sequestration on the U.S. Outer Continental Shelf.* (OCS Study BOEM 2012-100). Herndon, Virginia: U.S. Department of the Interior, Bureau of Ocean Energy Management.

This report discusses the onshore and offshore potential of CO_2 storage in the United States and technologies and costs of CO_2 capture and storage. The report also analyzes the potential economic viability of offshore storage, the potential benefits to society of offshore GS, and discusses the various trade-offs (e.g., environmental impacts and potential incompatibilities with oil and gas development).

Climate Change Mitigation

Alcade, J., Flude, S., Wilkinson, M., Johnson, G., Edlmann, K., Bond, C., Scott, V., Gilfillan, S., Ogaya, X., & Haszeldine, R. (2018). Estimating Geological CO_2 Storage Security to Deliver on Climate Mitigation. *Nature Communications, 9,* 2201.

In the paper, the authors present a numerical model to calculate CO_2 storage and leakage to the atmosphere over 10,000 years to address risk from leakage uncertainty. They found that with well-regulated storage, there is a 50% probability of retaining 98% of injected CO_2 over the 10,000-year period. For inadequately regulated storage, they found an estimated 78% of the CO_2 will be retained over the 10,000-year period.

Gale, J., Abanades, J., Bachu, S., & Jenkins, C. (2015). Special Issue commemorating the 10th year anniversary of the publication of the Intergovernmental Panel on Climate Change Special Report on CO_2 Capture and Storage. *International Journal of Greenhouse Gas Control, 40,* 1-5.

This paper summarizes a special issue of the International Journal of Greenhouse Gas Control that discuss various aspects of CCS. The authors conclude that CO_2 storage in deep saline aquifers is a secure option, and that the cost of this storage will decrease as leading technologies are deployed. Additionally, newly emerging technologies could lead to further cost reductions.

Intergovernmental Panel on Climate Change. (2022). *Climate Change 2022: Impacts, Adaptation and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change.* Cambridge, United Kingdom: Cambridge University Press.

The Sixth Assessment Report of the IPCC assesses the impacts of climate change, looking at ecosystems, biodiversity, and human communities at global and regional levels. It also reviews vulnerabilities and the capacities and limits of the natural world and human societies to adapt to climate change.

Intergovernmental Panel on Climate Change. (2015). *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge, United Kingdom: Cambridge University Press.

The IPCC concludes in this report that energy supply sector emissions are a major source of greenhouse gas emissions, and that CCS is an important technology for abating these emissions. In most mitigation scenarios that reach atmospheric concentrations of 450 parts per million of CO_2 in 2100, fossil fuel generation without CCS is almost entirely phased out by this time.