Bipartisan Policy Center

# $CO_2$ Sequestration by the Seashore

## COMPARING OPPORTUNITIES AND CHALLENGES FOR ONSHORE AND OFFSHORE GEOLOGIC CARBON STORAGE

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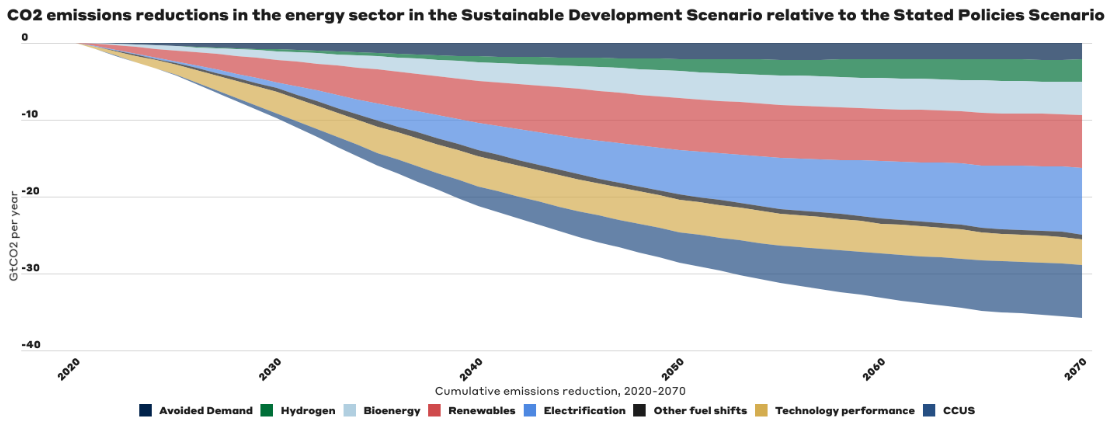
# Introduction

Carbon management technologies, in addition to aggressive efforts to lower emissions, will be crucial to achieving net-zero greenhouse gas (GHG) emissions this century, according to the International Energy Agency (IEA) and the Intergovernmental Panel on Climate Change (IPCC) (Figure 1). The term "carbon management" encompasses two broad categories: (1) technologies for capturing carbon dioxide ($CO_2$) from large emissions sources, such as industrial facilities and power plants, *before* it enters the atmosphere, also known as point source carbon capture, utilization, and storage (CCUS); and (2) technologies for removing $CO_2$ that is already in the atmosphere through direct air capture (DAC) and other carbon dioxide removal (CDR) mechanisms.[a] Whatever technology is used to capture $CO_2$, the next steps in point source CCUS and some CDR pathways (including DAC) involve concentrating and purifying the captured $CO_2$, compressing and transporting it—most commonly by pipeline—and, finally, either utilizing the $CO_2$ in a way that keeps it out of the atmosphere for a long period of time or injecting it into deep underground geologic reservoirs for permanent isolation. Because the infrastructure requirements for these steps are the same, this report uses the term CCUS for all kinds of industrial $CO_2$ capture, including DAC.

a Note that there is a fundamental difference between point source CCUS and CDR. The former leaves atmospheric concentrations of $CO_2$ unchanged by averting the addition of any new emissions. The latter reduces atmospheric concentrations of $CO_2$ by removing legacy emissions. Most assessments conclude that both will likely be necessary to address emissions from certain hard-to-abate sources and sectors, especially in the early years of the clean energy transition, and, in the case of CDR, to offset residual emissions that cannot be prevented from entering the atmosphere.

**Figure 1.** Role of CCUS in Reaching Net-Zero Emissions




The International Energy Agency's (IEA) Sustainable Development Scenario maps out how the global energy system would need to evolve to meet the climate targets of the Paris Agreement and reach net-zero emissions by 2070. The IEA's Stated Policies Scenario lays out the current trajectory of the global energy system based on existing policies and policies under consideration. This chart illustrates the role of CCUS (the lower-most blue-colored wedge) in anticipated carbon reductions to 2070 in the Sustainable Development Scenario versus the Stated Policies Scenario. Reductions illustrated here are 0.02 Gt/yr in 2023, growing to 0.61 Gt/yr in 2030 and 4.00 Gt/yr in 2050. Note that 1 gigaton (Gt) equals 1 billion metric tons. Image created using data from IEA's CCUS in Clean Energy Transitions report. Available at: [https://www.iea.org/reports/ccus-in-clean-energy-transitions.](https://www.iea.org/reports/ccus-in-clean-energy-transitions)

The scale of the carbon management challenge is immense, given still-growing global energy demand, the current pace of decarbonization in key sectors, and the mitigation efforts needed to achieve climate objectives. According to modeling by the IEA, the CCUS industry will need to scale up by a factor of 100 in 25 years to help countries remain on track to meet their current climate commitments.[1] Enabling this level of scale-up will require further investment and targeted policy investments, both to accelerate the development and deployment of cost-effective $CO_2$ capture technologies and to build the infrastructure needed to handle, transport, and utilize or sequester $CO_2$.

This report focuses on infrastructure challenges and requirements for the geologic storage of $CO_2$. Although a range of efforts are underway to develop promising options for utilizing or converting $CO_2$, the capture quantities required to make a meaningful contribution to climate change mitigation far exceed project utilization opportunities: Permanent subsurface storage, along with the infrastructure needed to deliver and inject $CO_2$ at storage sites, must be scaled up substantially. Fortunately, the science of geological storage is mature, and subsurface injection can be implemented safely and effectively, as demonstrated by decades of experience from oil and gas industry operations in the United States and abroad.[2]

The following sections provide an overview of key trade-offs and considerations for geologic storage of $CO_2$ in both the onshore and offshore settings, organized by:

- Technical subsurface and infrastructure requirements
- Environmental impacts, permitting, and community concerns
- Regulatory and other legal considerations
- Costs

We draw from experience with demonstration projects around the world and address many of the key questions raised by policymakers regarding these issues. A central conclusion is that policy support will be needed for both onshore and offshore geologic storage to provide capacity at the scale needed to reach critical climate goals.

# Context and Background

Permanent injection and storage of $CO_2$ in deep geologic formations is a well understood and commercial practice in the United States and worldwide. The United States has a 51-year history of onshore injection, primarily for purposes of enhanced oil recovery (EOR). Norway has been implementing offshore CCUS projects with dedicated saline storage for 27 years (Text Box 1). Interest in carbon management is also growing rapidly in response to ambitious climate policies. Worldwide capacity at CCUS facilities grew to 361 million tons per year in 2023—a 48% increase from 2022.[3]

Despite this long history of and growing interest in geologic $CO_2$ storage, there are concerns that storage capacity will not grow rapidly enough to keep pace with increased deployment of capture technology. According to a 2023 report on the status of the industry from the Global CCS Institute:

> "The rate of development of geological storage resources is not keeping pace with potential future demand, even in leading jurisdictions and especially in Europe. Unless dedicated programs are put in place to identify and appraise geological storage, sufficient capacity may not be available when required."[4]

In the United States, dozens of onshore leases are targeted for carbon management projects (Figure 2), compared with just 10 offshore leases intended for development in Texas and Louisiana. This imbalance reflects the nation's long-time focus on onshore storage research and development, despite recent growing interest in offshore storage. Taken together, offshore leases in state and federal waters represent a larger total area than areas under lease for onshore carbon management, which suggests that offshore storage will play a significant role going forward.

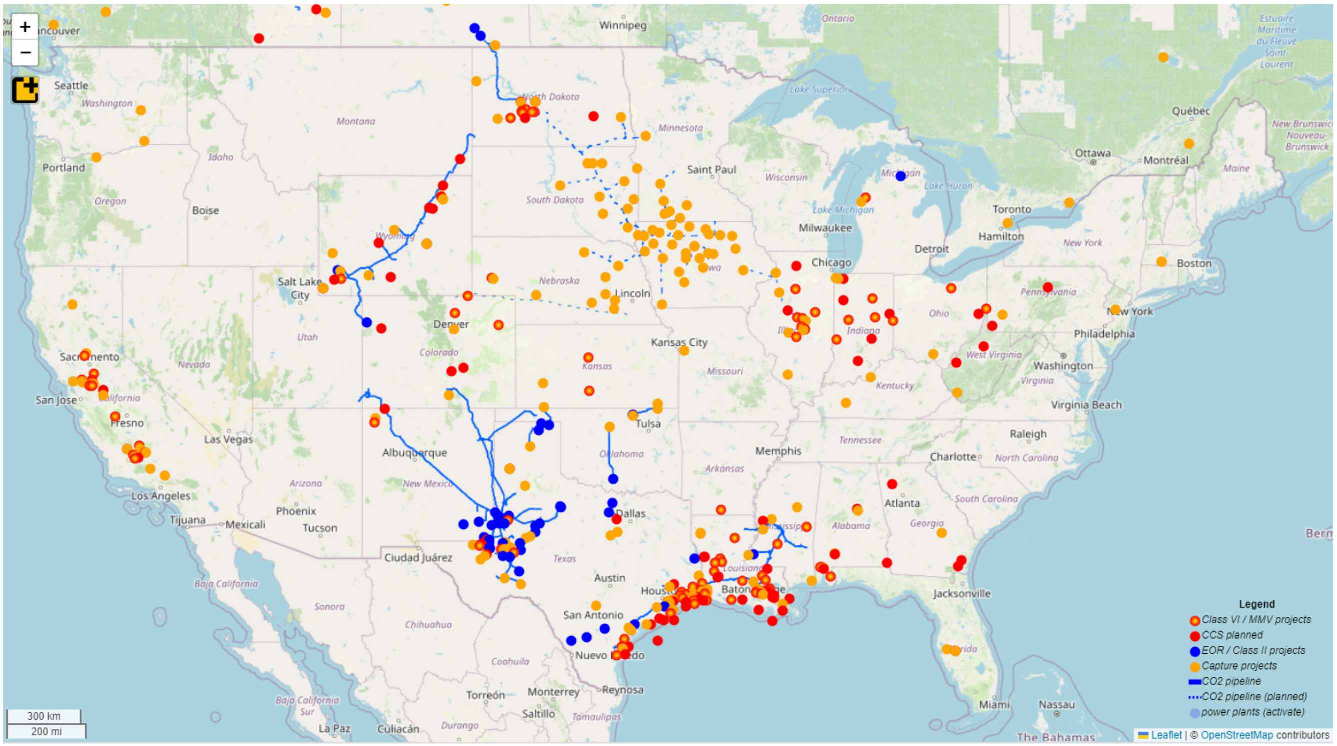
## TEXT BOX 1. TWO REGIONAL EXAMPLES OF EXTENSIVE ONSHORE AND OFFSHORE $CO_2$ STORAGE ACTIVITY

**Onshore: Texas, USA**—Oil companies operating in the Permian Basin of west Texas have been injecting $CO_2$ for EOR for 51 years. This activity includes hundreds of miles of existing interstate $CO_2$ pipelines and hundreds of $CO_2$ injection wells. Studies of the overlying groundwater systems have shown no environmental impact from the injection of more than 175 million tons of $CO_2$.[5] Texas also hosts two industrial $CO_2$ capture projects, one at a steam methane reforming hydrogen facility in Port Arthur and the second involving postcombustion capture at a coal-fired power plant southwest of Houston. Captured $CO_2$ from these projects has been used for EOR in depleted Gulf Coast oil fields. Many more onshore dedicated storage projects utilizing saline formations are currently planned. Texas now has thousands of square miles of onshore and, more recently, offshore leases for $CO_2$ storage under development.

**Offshore: Norway**—Due to geology unsuitable for onshore $CO_2$ storage, Norway has focused entirely on offshore storage. Equinor, a majority state-owned energy company headquartered in Norway, has 27 years of operational carbon capture and storage (CCS) experience in the North Sea. It operates the Sleipner project, which is the longest-running dedicated CCS project in the world not related to EOR. At Sleipner, $CO_2$ is captured from offshore natural gas production facilities and reinjected into a saline aquifer (Utsire Formation). Extensive monitoring of the Sleipner site has demonstrated that the operations are safe and the subsurface containment effective. A second Equinor subsea storage project is underway at Snøhvit. It involves transporting captured $CO_2$ from an onshore gas production facility to an offshore storage site via a 120-km-long marine pipeline.

To date, the cumulative $CO_2$ stored between the Sleipner and Snøhvit projects exceeds 22 million tons. Multiple offshore commercial storage leases (licenses) are now being developed for CCS in the North Sea. In addition, $CO_2$ transport vessels and marine pipelines are being incorporated into the Northern Lights Project, currently under construction. Northern Lights aims to transport and sequester $CO_2$ produced by the industrial sector, targeting a capacity of 1.5 million tons per year in phase 1 (with startup in 2024) with the potential to expand to 5 million tons per year as demand grows.

**Figure 2.** Existing and Planned Onshore CCUS Projects in the U.S.

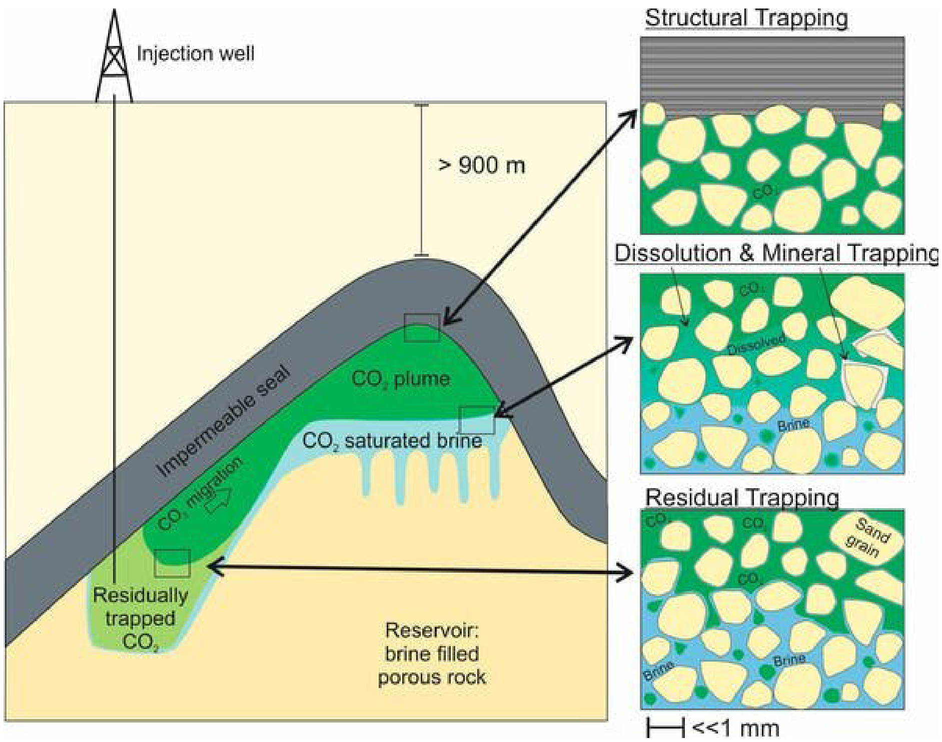



Projects include Class VI wells for geologic storage of CO2. The map does not include 10 leases for offshore storage in state waters in the Gulf of Mexico. Map generated by CCUSMap. Available at: https://ccusmap.com.

At its most basic, geologic $CO_2$ storage—both onshore and offshore—involves injecting $CO_2$ using mature well designs into deep geologic formations (3,500 feet to 10,000 feet below the Earth's surface) that have sufficient porosity and permeability to receive economically significant amounts of $CO_2$ over a decade or more of injection. These geologic formations are the same rock types that have held hydrocarbon accumulations (sandstones and carbonates) for millions of years. Once the $CO_2$ is injected at these depths, it displaces resident brine in the pore space and increases the net subsurface fluid pressure. At this elevated pressure, $CO_2$ exists in a liquid state and is less dense than resident brine, making it buoyant. For this reason, potential formation sites require "caprocks" of nonporous and impermeable rocks (typically shale) that restrict vertical migration and retain the $CO_2$ in the injection reservoir.

The underlying physics of underground $CO_2$ storage are analogous to the physics of hydrocarbon retention, which has been studied extensively for decades in the oil and gas industry. There are also well studied natural subsurface $CO_2$ accumulations that have remained untouched for millions of years. These natural reservoirs provide analogs for understanding the long-term retention of injected $CO_2$.[6] $CO_2$ that has been injected underground is retained in reservoir rocks by multiple physical mechanisms, including structural trapping by the cap rock, dissolution into brine, mineralization into carbonate minerals, and local residual trapping at the pore (micron) scale (Figure 3). These multiple mechanisms provide layers of redundancy and security for ensuring that the $CO_2$ remains permanently trapped far underground.

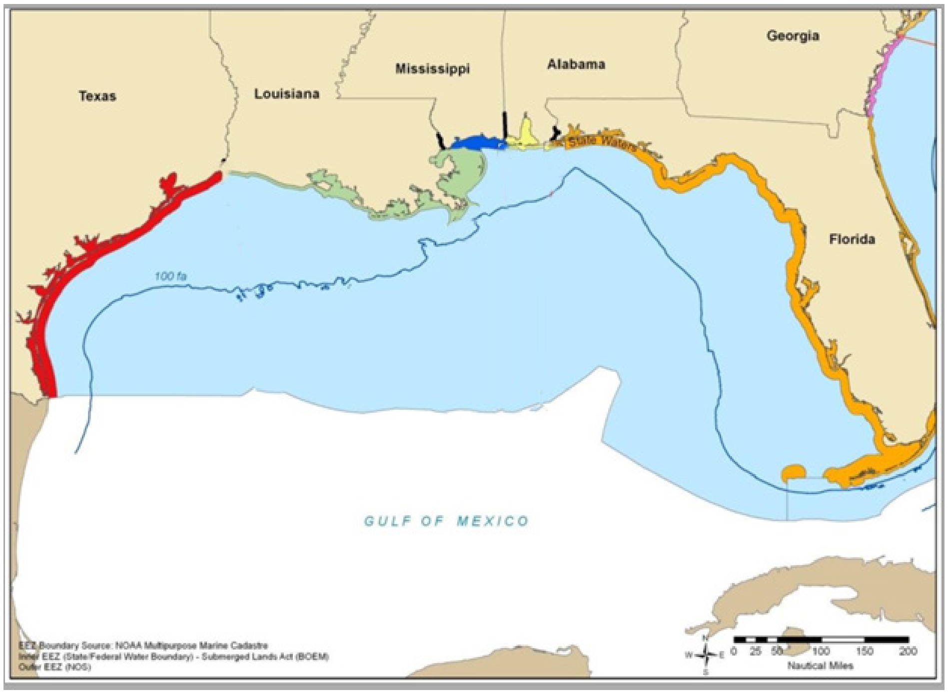
**Figure 3.** Modalities of Underground $CO_2$ Storage




Schematic depiction of different ways that $CO_2$ becomes permanently stored underground. Available at: https://phys.org/news/2020-03-carbon-capture-storage-stalled-needlessly.html.

One differentiating factor for the construction and operation of onshore geologic reservoirs relative to offshore storage is whether the land is privately or publicly owned. Land ownership affects potential royalties and lease arrangements for external drilling operations. Conversely, offshore sites are all publicly owned, either by states or the federal government (Figure 4), which can lower some barriers related to ownership and leasing.

**Figure 4.** State and Federal Offshore Waters




Map of state waters (shaded in color for each state) with established boundaries between states extending into federal offshore waters. Image modified from Figure 1.1.1 of "Mississippi Management for Recreational Red Snapper." Image modified from original, available at: [https://gulfcouncil.org/wp-content/uploads/B-6e2-Mississippi-State-Management-1-8-2018.pdf](https://gulfcouncil.org/wp-content/uploads/B-6e2-Mississippi-State-Management-1-8-2018.pdf).

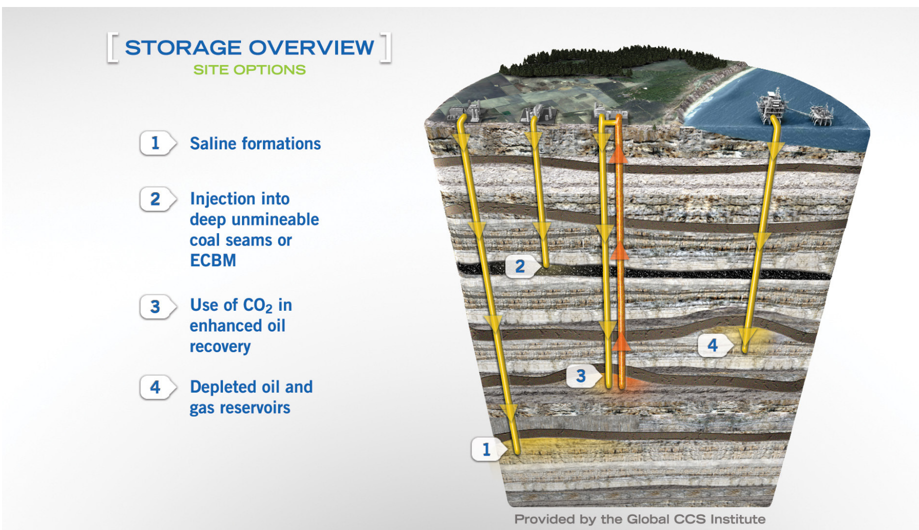
To expand opportunities for offshore carbon storage in the United States, the Bipartisan Infrastructure Law (BIL) amended the Outer Continental Shelf Lands Act and authorized the Department of the Interior (DOI) to administer leases, easements, and rights-of-way on the Outer Continental Shelf for geologic storage of $CO_2$. DOI was also directed to promulgate implementing regulations for these activities. Following common practice, DOI determined that the Bureau of Safety and Environmental Enforcement (BSEE) would be responsible for offshore CCUS activities related to installation, operations, emergency response plans, and decommissioning. DOI decided that the Bureau of Ocean Energy Management (BOEM) would be responsible for leasing and for assessing environmental impacts from an offshore CCUS program. Initial draft guidance on the new authorities granted to BOEM and BSEE under the BIL is expected in 2024.

# Technical Subsurface and Infrastructure Requirements

## SUBSURFACE GEOLOGY

Promising subsurface geology for $CO_2$ storage exists both on land and offshore (Figure 5). Onshore projects require land leases for the acreage needed to host injection equipment and operations and to cover bottom hole well locations. Offshore projects can be sited in a variety of locations off the coast, including coastal bays and estuaries. Injection wells in landlocked (and generally fresh or brackish) water bodies such as lakes are considered onshore projects in the United States, although their requirements might overlap in some technical respects with offshore projects (e.g., in terms of well access and potential environmental effects). In most coastal areas, the onshore subsurface geology is continuous with the offshore subsurface geology, such that $CO_2$ storage opportunities exist in the same geologic formation and could be hydrologically connected beneath the surface.

**Figure 5.** Onshore and Offshore Settings for $CO_2$ Storage




The geologic continuity illustrated between onshore and offshore injection sites is realistic for many coastline settings in the United States and globally, such that the storage sites being accessed are similar regardless of whether the injection occurs onshore or offshore. For economic reasons (cost of development), CO2 injection for EOR and enhanced coalbed methane recovery (ECBM)—options 2 and 3—is considered to be more feasible onshore, although this may change in the future. One geologic setting is not represented in this figure: mafic reservoirs, such as basalt, which exists in some onshore settings and is a dominant rock type in distant ocean basins. Available at: [https://www.globalccsinstitute.com/resources/ccs-image-library/](https://www.globalccsinstitute.com/resources/ccs-image-library/).

For offshore projects sited farther from the coast, the probability that the subsurface geology is significantly different from onshore sites is higher. Although there are some differences between onshore and offshore sites when it comes to identifying and characterizing suitable subsurface pore space geology—including reservoir and confining system extent, injectivity, and storage resource quantification—the methods and data used, including well logs or subsurface seismic data, are largely similar. Certainly, the need to demonstrate long-term integrity for isolating $CO_2$ is the same for all geologic storage sites.

The subsurface geologic and geophysical data available for different sites may vary, of course, although information about offshore sites is generally more accessible than for onshore locations. Historical exploration of offshore areas means that much of the ocean subsurface has been imaged using 3D seismic technology, with some exceptions.[7] In offshore areas under federal jurisdiction in the United States, these seismic data are released into the public domain after 25 years.

In the United States, the most likely region for large-scale offshore $CO_2$ storage development is the Gulf of Mexico, which has been surveyed extensively over the 75 years of active oil and gas exploration. The ability to access 3D seismic data for thousands of square miles off the Gulf Coast reduces costs for initial $CO_2$ storage site assessment in this area. By contrast, $CO_2$ storage in the tectonically active offshore regions of the West Coast is not currently being pursued. Similarly, no projects have been announced off the East Coast, where a long-term drilling moratorium is in effect for several offshore areas, although there have been some efforts to study potential regional storage sites.

For onshore injection sites that are far inland from the coast, the geological formations that could be accessed for $CO_2$ storage can be much older than for offshore settings (i.e., hundreds of millions of years old onshore, versus tens of millions of years old offshore). Older rocks are generally more brittle than the younger rocks targeted for $CO_2$ storage in offshore settings because they have had more time for subsurface alteration, such as cementation. This difference has implications for rock strength and for the potential of $CO_2$ injections to induce microseismicity.[8] Offshore sedimentary rock formations (aside from basalt) tend to be geologically young (under 30 million years old), which typically results in more ductile rock response. This suggests that the risk of induced microseismicity may be generally lower in offshore settings,[9] although many other factors besides rock age (e.g., fluid pressure, ambient subsurface stress field) must be considered in assessing seismicity risk.[10] For perspective, it is worth noting that the magnitude of any microseismic event likely to be induced by $CO_2$ injection is on the order of -2 to +2, which is approximately the microseismicity a person would register from dropping a book on the floor. Monitoring for microseismicity at the ground surface can be challenging due to significant ambient noise. Deployments of sensors hundreds of feet below the ground surface (i.e., in shallow boreholes) can detect magnitudes down to -2.0. Measurements at the Quest $CO_2$ storage project in Canada detected induced microseismicity in a range from -2 to 1.[11]

The technical differences between onshore and offshore settings mean the specifications for construction materials and the protocols for accessing injection wells and monitoring them will differ. Onshore and offshore settings pose different technical challenges, including for construction materials and the protocols for accessing injection wells and monitoring them. Onshore wells are nominally accessible at any time with standard personnel and equipment, whereas access to offshore wells is subject to additional health, safety, and environmental requirements. As a result, offshore wells are generally less accessible, which leads to higher costs. However, injection operations themselves and the design and engineering of wells may be very similar for onshore and offshore sites.

Technology for offshore drilling operations has evolved significantly over the past 50 years, to the extent that some underwater construction can be done without the elevated platforms that have historically been required for oil and gas operations. Both onshore and offshore $CO_2$ storage can benefit from advances in drilling technology that have made long, deviated lateral wells (as opposed to traditional vertical wells) quite common today.

A typical well can accommodate the injection of as much as 1 million tons $CO_2$ per year (1 $MtCO_2$/yr ). The injection rate at the Sleipner $CO_2$ storage project in the North Sea (Text Box 1) is 0.9 $MtCO_2$/yr. Wastewater injection rates at several wells in the Gulf Coast are equivalent in mass to 1 $MtCO_2$/yr, suggesting that injection capacity itself is not typically a constraint, although injection rates will vary depending on the underlying geology.[12] Typical power plants or industrial facilities emit more than 1 $MtCO_2$/yr, while emissions from hydrogen production facilities can be several million tons per year. For this reason, multiple injection wells may be needed to service the $CO_2$ storage needs of a single large emissions source. Storage facilities can also be designed to receive emissions from multiple sources.

## $CO_2$ TRANSPORT

Developers of new geologic storage sites will need to consider ease of access to captured $CO_2$ emissions from upstream sources. In the United States, large point-source emitters are concentrated in coastal ports and at large industrial centers in coastal regions (e.g., the Houston ship channel and Beaumont-Port Arthur in Texas, Lake Charles in Louisiana, and the Mississippi River industrial corridor between New Orleans and Baton Rouge). The proximity of these emissions clusters to the coast makes offshore areas, as well as onshore areas in the vicinity, attractive for developing large CCUS projects.

Transportation infrastructure requirements for onshore storage are typically less technically complex than for offshore because $CO_2$ can be delivered through pipelines, over relatively short distances in some cases. The United States already has thousands of miles of $CO_2$ pipeline, which offers the most efficient means for transporting large volumes of $CO_2$ over modest distances. In general, drilling rigs are also available onshore—a suite of active rigs are capable of drilling the needed wells.

Offshore storage requires more sophisticated transportation infrastructure (Figure 6), often involving pipelines buried in shallow sediments below the seafloor and/or marine vessels to transport $CO_2$ from capture facilities to storage sites. Examples of offshore $CO_2$ pipelines for CCS exist in the Norwegian North Sea. Establishing new transport pipeline corridors or using existing rights-of-way in U.S. offshore areas is feasible and being considered.[13] Repurposing existing idle pipelines for $CO_2$ transport has been considered, but the opportunities appear quite limited due to the different environmental and technical demands of moving $CO_2$, versus the materials these pipelines were originally designed for.

**Figure 6.** Components of an Offshore $CO_2$ Storage Project

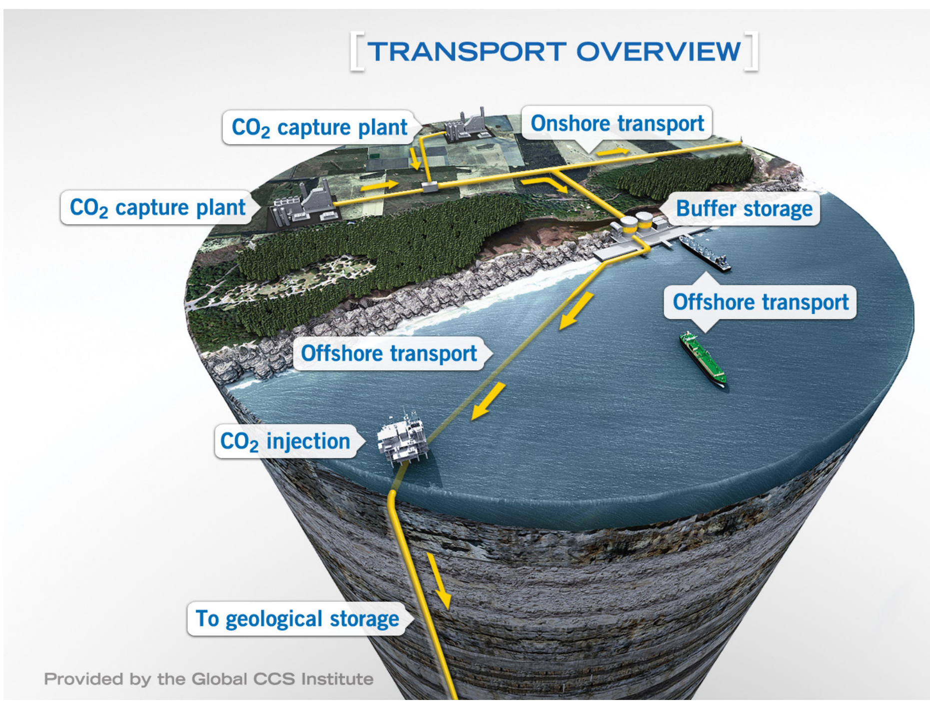



Image sourced from Global CCS Institute. Available at: https://www.globalccsinstitute.com/resources/ccs-image-library/.

Transporting $CO_2$ by vessel rather than by pipeline holds certain advantages, as vessels have more flexibility in where they can go. Although most projects are likely to have fixed $CO_2$ offtake and transport agreements, a vessel can transport $CO_2$ to another location for offloading and storage if an injection well is taken offline for maintenance, or if a storage site has reached capacity or is experiencing operational challenges. Efforts to develop vessels for transporting liquefied $CO_2$ are underway and are being incorporated in some international offshore storage projects (notably in the North Sea, but this concept is also drawing interest in the Gulf Coast). To establish feasibility and precedent, the Greensand Project in the southern North Sea has included transborder shipments of $CO_2$ by vessel to a storage location for injection and permanent storage. Rystad Energy estimates that a fleet of 55 $CO_2$ carriers will be required by 2030 to meet anticipated demand from offshore storage projects.[14]

Offshore rigs in the shallow water depths of the Inner Continental Shelf are no longer very active since resource extraction has largely moved to deep-water portions of the Gulf of Mexico more than 50 miles from the coastline. Costs for offshore drilling rigs are generally higher than for onshore rigs, and their availability is low given minimal hydrocarbon activity in the inner shelf of the Gulf. Such projects typically have fewer wells, larger well spacing, and higher injection rates per well.

# Environmental Impacts, Permitting, and Community Concerns

The practice of injecting $CO_2$ into the deep subsurface is well established. There is a 51-year history of safe $CO_2$ injection onshore in the Permian Basin of west Texas, and a 27-year history of injecting $CO_2$ beneath the Norwegian North Sea. $CO_2$ injection for EOR or dedicated storage in saline formations has also occurred at many other locations around the world for many years.[b] Overall, the track record from existing projects suggests that leakage events are rare, low impact, and manageable with routine practices.

Despite their demonstrated safety, onshore carbon management projects have drawn some negative public reaction. Two notable examples are the Barendrecht storage project in the Netherlands and the Navigator $CO_2$ pipeline in the midwestern United States. Both were ultimately canceled after public opposition complicated project development and led to added cost.[15,16] Officially, the Navigator pipeline was abandoned due to the "unpredictable nature of the regulatory and government processes involved," but public opposition likely factored into the decision.

In fact, public acceptance may be a greater challenge for onshore storage than for offshore storage, especially if $CO_2$ storage sites and pipelines are near populated areas. As with any industrial facility, some communities might also be concerned about traffic related to construction and operation. Increased development of offshore projects, meanwhile, could prompt greater concern about potential impacts on the marine environment due to $CO_2$ leaks and other project-related activities. The sharing of best practices from the oil and gas sector relevant to the operational aspects of offshore storage—including well completion and control, well monitoring, and compliance with well permitting—could mitigate some of these concerns.

## PERMITTING

The fundamental considerations for permitting geologic $CO_2$ storage facilities are relatively similar. Permit applicants must demonstrate that the project can operate as intended without presenting risks to safety and the environment. The permitting process will need to consider $CO_2$ plume distribution over time,

[b] Descriptions of existing onshore and offshore projects can be found at the GCCSI CCS Facilities Database, https://co2re.co/FacilityData.

pressure elevation, and the interaction of both with risk elements such as legacy wells, local fracture pressure, and geologic faults.

The primary permitting requirement for onshore wells is the protection of underground sources of drinking water (USDW). Onshore storage requires appropriate geology to prevent leaks that could cause potential groundwater contamination and present risks to humans and local ecosystems. Under the Safe Drinking Water Act, the Underground Injection Control (UIC) program protects USDW. Under this U.S. Environmental Protection Agency (EPA) program, a separate permit class—Class VI—has been established for the safe and permanent disposal of $CO_2$ underground. Potential subsurface impacts to be considered in well permitting include $CO_2$ vertical and/or lateral migration, mobilization of naturally occurring minerals due to dissolution in lower-pH groundwater, and pressure elevation and vertical brine displacement into shallow stratigraphy.[c] Surface impacts to be considered in the permitting process include road and well pad construction, electrical line installation, and changes in land use.

Only three states—Wyoming, North Dakota, and Louisiana—have been granted primary authority over Class VI well permitting (a designation known as "primacy") after undergoing an application process to demonstrate their regulations are at least as protective as EPA's. Louisiana most recently received primacy at the end of 2023; Texas is applying for a primacy determination.

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EPA—or the state regulatory agency in states with primacy—has authority over Class VI permitting for geologic storage in offshore areas under state jurisdiction. DOI is developing draft regulations for $CO_2$ injection in federal offshore waters under new authorities granted by the BIL. It is worth noting that regulations applicable to underground sources of drinking water are unlikely to be considered, as these sources typically do not exist in shallow stratigraphy. Thus, the focus of permit compliance and monitoring is likely to transfer to the seafloor sediments and marine water column as opposed to subsurface USDW.

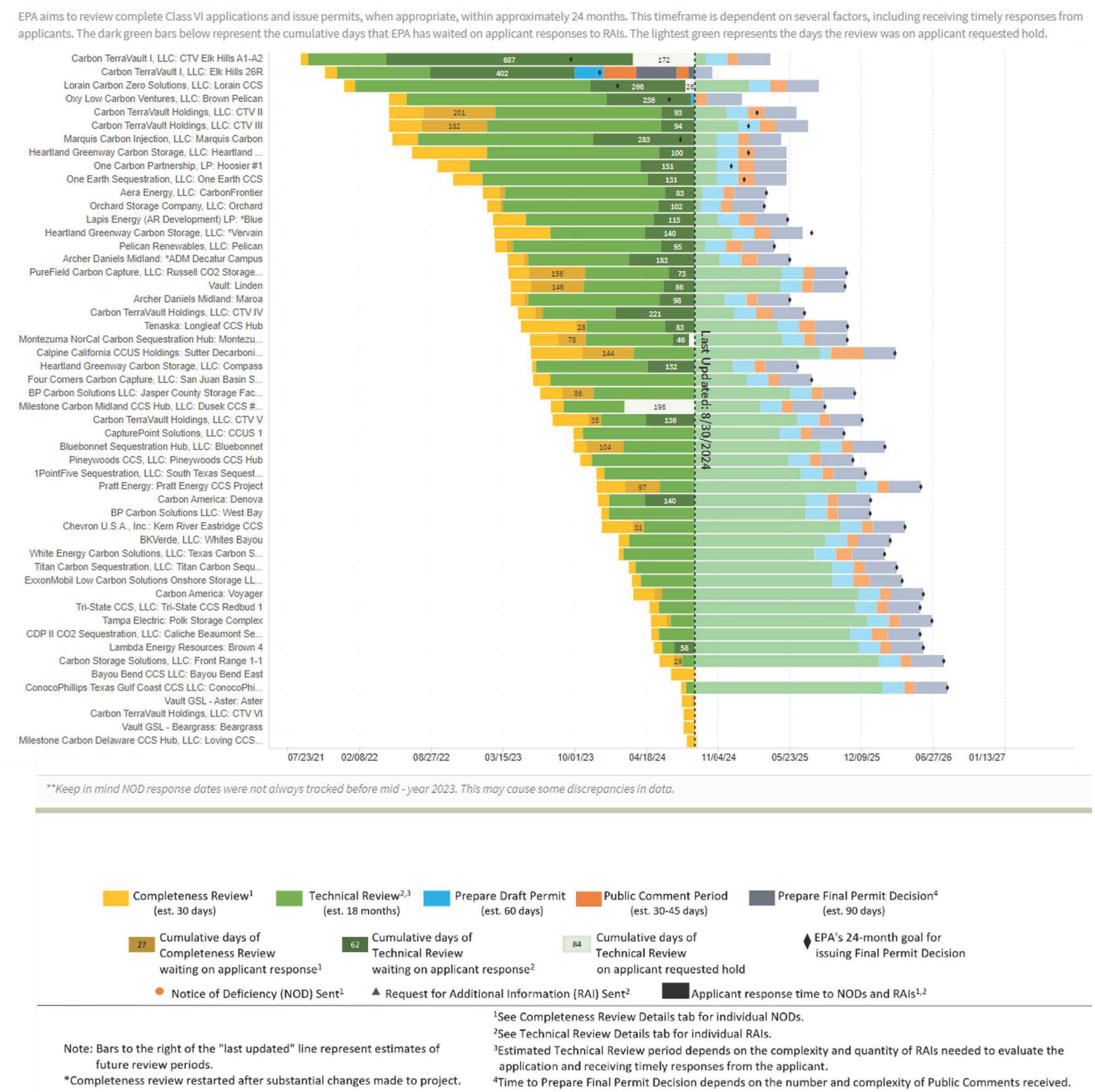
[c] For more details on what is required for consideration in a Class VI well permit, see EPA's webpage, https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-carbon-dioxide.

DOI's forthcoming regulations will be able to draw from experience with EPA's Class VI regulations and from several decades of experience with offshore injection from around the world. Best practices for environmental integrity have also been evaluated at length over the past decade, with the general conclusion that offshore $CO_2$ storage is safe, provided site selection and monitoring are rigorous.[17,18,19] Another important consideration that has been extensively researched is the potential long-term impact of $CO_2$ on marine ecosystems. For example, findings from field experiments with controlled $CO_2$ releases in shallow seafloor sediments suggest that the effects were generally minimal but did disrupt some sediment. The experiments also observed $CO_2$ bubbles in the water column, and avoidance by fauna.[20] These small disruptions should continue to be studied to better understand the potential long-term impacts of offshore carbon storage practices.

Uncertainty about the timeline of Class VI well permitting is one of the most significant challenges to date for developing onshore projects. Timeline uncertainties are important because CCUS projects also need to contend with permitting, engineering, and construction challenges for $CO_2$ capture and transport. Capital investments in the CCUS value chain are interdependent, and permitting delays for the storage portion affect other, nonstorage aspects of a CCUS project. Fortunately, efforts are underway to increase EPA's capacity to accelerate current timelines for well permitting and to also handle the expected increase in permit applications. Evidence of this shift is provided in Figure 7, which shows a tracker unveiled by EPA at the end of 2023 that periodically updates the status of Class VI injection well permit applications. The first Class VI permit in nearly a decade was approved on January 24, 2024. Another 43 projects with 128 well permit applications are under EPA review; this tally does not include those applications being reviewed by the states that have primacy over Class VI injection wells (Wyoming, North Dakota, and Louisiana).

Uncertainty about the timeline of Class VI well permitting is one of the most significant challenges to date for developing onshore projects.

## **Figure 7.** EPA's Class VI Permit Tracker



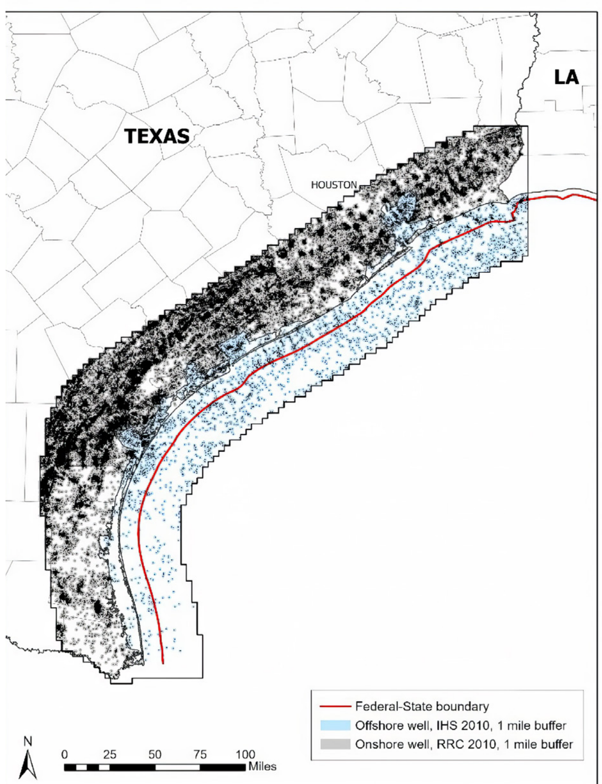

EPA's Class VI Permit Tracker as of August 30th, 2024, illustrating the timeline and current status of 148 total Class VI permit applications in progress for 52 projects in seven different EPA regions. The current permitting process takes many years, which complicates timelines for project development. All 148 well permits currently in process are for onshore wells; none is for an offshore well. Available at: https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.

## OTHER ENVIRONMENTAL CONSIDERATIONS

One of the most significant risks to $CO_2$ storage projects is the presence of legacy (abandoned or idle) wells. In some onshore and offshore settings, dozens of such wells could be within the area of review for permitting. For economic reasons (it is more expensive to drill offshore than onshore), as well as historical reasons (offshore well development came much later than onshore well development), offshore settings typically have fewer and younger wells.[21] This suggests that offshore sites are less likely to require the management of legacy wells during permitting and operations. If a legacy well requires intervention, however, the costs are likely to be higher offshore than they would be onshore.

Estimates of onshore well density can be as high as tens of wells per square mile, while estimates of offshore well density are usually below 10 wells per square mile.[22] State and federal offshore regions in the Texas portion of the Gulf of Mexico have many more nine-square-mile grid size areas with no wells than onshore regions (Figure 8).

**Figure 8.** Legacy Wells in the Near Onshore and Offshore Portions of the Texas Coast




Well densities are much higher onshore (gray areas) than offshore (blue areas), and it is difficult to find areas far from existing wells (white areas) in onshore settings. The red line is the boundary between state and federal offshore jurisdiction. Figure based on data from: https://doi.org/10.1002/ghg.2220.

As discussed earlier, both onshore and offshore settings require ongoing monitoring and verification to ensure the integrity and security of stored carbon. Monitoring is needed to detect potential leaks or issues that might arise, especially from legacy wells.[23] Although the specific technologies used for monitoring can vary, the primary observations of interest (pressure, $CO_2$ plume extent, indications of out-of-zone migration) are the same. The area of review in a permit application depends on geology and intended injection amounts, and is generally not influenced by whether the proposed site is onshore or offshore.

Monitoring costs are site-specific. However, some types of monitoring data may be easier and cheaper to acquire offshore than they would be onshore. This is most likely the case for seismic data, because large areas can be surveyed relatively easily using conventional ship-based technologies. In addition, the rapid recent development of autonomous marine vehicles suggests that cost-effective monitoring might be easier to deploy in marine settings.

There have been few documented cases of leakage from $CO_2$ injection wells. In addition, the U.S. Department of Energy (DOE) has dedicated substantial funds to research on this topic over the past 15 years. EPA Class VI regulations require that there be no leakage from injection wells and existing legacy wells in the "Area of Review." To address the large number of legacy wells in the vicinity of many onshore CCUS projects, policymakers have recently directed additional federal funding toward remediating improperly abandoned wells. In cases of $CO_2$-EOR, operators in west Texas have encountered some well leakage, but this leakage was eliminated by remediating the wells that were causing the problem. No legal cases concerning leakage have become public. A dispute over possible $CO_2$ leakage arose at the Weyburn $CO_2$-EOR field in Canada (also known as the Kerr Farm incident), but an independent determination found the issue to be unrelated to $CO_2$-EOR operations at this site.[24] More recently, EPA sent a letter to Archer-Daniels-Midland (ADM) in August 2024 informing the company that it had violated the Safe Drinking Water Act and its Class VI permit following the unintended migration of liquefied $CO_2$ into "unauthorized zones" at its Illinois carbon sequestration site. According to public reports, the carbon dioxide remained 5,000 feet underground and did not affect groundwater or risk entering the atmosphere. The EPA has issued an enforcement order, and ADM has noted it is working with the EPA to fix the issue.

Under authorities granted by the BIL, BOEM established a rulemaking team for offshore $CO_2$ storage in May 2022. The team is tasked with considering a range of issues, including financial, economic, and environmental issues; pre-lease exploration/site characterization; leasing; plans for operations, facilities, and pipelines; well qualification and offset infrastructure; emergency response and mitigation; monitoring and reporting; decommissioning; and liability.[25] BOEM subsequently authorized three national CCS environmental studies programs covering the Atlantic Ocean, Gulf of Mexico, Pacific Ocean, and Alaska. These programs will study the potential effects of $CO_2$ migration and leaks, fugitive emissions, and cumulative impacts of offshore CCUS on human and marine environments.

# Regulatory and Other Legal Considerations

Regulatory and legal considerations need to be addressed for both onshore and offshore CCUS projects to ensure they are successfully implemented. These considerations can vary widely by country and region.

Onshore storage is subject to a variety of land-use regulations, property rights, and liability issues. Acquiring land or securing access rights for CCUS facilities and pipelines is essential. Landowners need to be compensated, and property rights must be respected. The current precedent in most states is that leases for $CO_2$ storage must be negotiated with the land surface owner.

Offshore storage involves maritime regulations, interactions with traditional oil and gas operations, and, in some cases, international agreements or conflicts over jurisdiction in transboundary waters. In the United States, international agreements and transboundary issues are less relevant, as CCUS activities are most likely to occur in areas under state or federal jurisdiction. As discussed earlier, BSEE and BOEM are drafting rules that will address many technical and operational aspects of offshore carbon capture and storage. Following common practice, BOEM is responsible for leasing in federal waters. BSEE will be responsible for environmental and permitting enforcement. In addition, many activities such as offshore pipeline development will be subject to various state regulations, as well as rules set by the Army Corps of Engineers.

## LEASING AND OWNERSHIP

Because geologic storage injection sites are intended to operate for a decade or more, subsurface pressures are expected to reach elevated (but safe and regulated) levels. This pressure aspect causes project developers—both onshore and offshore—to seek large land areas for potential projects as a way to reduce pressure by distributing the $CO_2$ over a larger area. For example, current land leases onshore near the Gulf of Mexico average around 50 square miles (but can be as small as a few square miles).

In both onshore and offshore settings, the surface owner is usually (although not in all states) the owner of the subsurface pore space to be used for $CO_2$ storage. Thus, lease agreements must be made with the land surface owner. Onshore land lease areas may (and have been to date) leased from a combination of public and private entities. In many cases, land must be leased from multiple surface owners because the storage area underlays multiple adjacent land surface areas.

In cases where multiple land parcels are integrated into a single operating unit for purposes of a $CO_2$ storage project, a legal process of "unitization" is used to designate partial ownership across different parties. This process can complicate the ability to secure enough acreage for an onshore commercial project to proceed. In Texas, the 2023 legislative session included public hearings on lease integration, but the topic was not deemed urgent enough to advance formal legislation. It is expected to be revisited in the 2025 legislative session. Oklahoma is considering bills related to unitization and long-term liability transfer to the state.

Offshore leases are fewer in number but much larger in scope, averaging over 300 square miles. They almost exclusively utilize public waters managed by a single state or the federal government. In state waters, offshore leases are handled in accordance with state law. In the case of Texas, the responsible agency is the Texas General Land Office. Ten offshore state-issued leases for $CO_2$ storage have been concluded to date (seven in Texas and three in Louisiana). The process for leasing federal waters for $CO_2$ injection will be determined by BOEM's forthcoming regulations. Leases on the Outer Continental Shelf are likely to be even larger than those in state waters, in some cases over 800 square miles. There are no ownership conflicts in offshore areas, because there is only one landowner and the lease areas are large enough to avoid conflicts with adjacent offshore areas.

Revenues from onshore projects are used to pay surface landowners, who can include a combination of private and public entities. For offshore state waters, fees are paid to the state and handled in accordance with state law. In the case of Texas, money from $CO_2$ leases and injection royalties are deposited in the Permanent School Fund, which supports primary school education throughout the state. Lease bonus payments for offshore CCS in Texas state waters were estimated to total $133 million in 2023, with potential state revenues approaching $10 billion over 25 years. Funds collected from federal offshore oil and gas leases go to DOI and are used for targeted purposes—a similar arrangement could apply to $CO_2$ leases. Taking the Gulf of Mexico as an illustrative example, oil and gas funds are returned to states that participate in the Gulf of Mexico Energy Security Act (GOMESA) program, which shares leasing revenues with Gulf producing states and the Land & Water Conservation Fund for coastal restoration projects. Neither BOEM nor BSEE has publicly discussed the applicability of GOMESA or other royalty arrangements to $CO_2$ storage, but they might address the issue in their forthcoming rules.

While no federal lands have yet been leased for $CO_2$ injection, the White House has developed a task force for evaluating carbon storage potential on federal lands, including federal waters offshore. Without legislative changes or finalized rules from BOEM and BSEE, holders of current and future leases in the federal Outer Continental Shelf will not be legally permitted to inject $CO_2$ for geologic storage.

## LIABILITY

Liability during injection and after injection ceases is a topic of continuing discussion for onshore and offshore geologic storage. Short-term operational liability is well understood and documented within EPA's rules for Class VI injection wells, but long-term liability in the post-closure (postinjection) phase has been more challenging to legislate.

It is generally understood that project operators will remain liable for a significant period postinjection, but that, at some point after formal closure and postinjection monitoring, long-term responsibility will pass from the operator to the state. The EPA's UIC Class VI Financial Responsibility Guidelines state that postinjection site care and closure stages should last 50 years unless an alternative time frame has been approved by the UIC program director. Currently, different states require different periods of postinjection monitoring prior to formal site closure and transfer of long-term liability (Table 1).

**Table 1.** Long-Term Liability for CCS Projects by State

| State | Minimum Number of Years Before Transfer of Liability | Statute |
|---|---|---|
| California | 100 | Ca. Pub. Res. Code §71464 |
| Montana | 50 | Mont. Code Ann. §82-11-183(3)(f) |
| Wyoming | 20 | Wyo. Stat. Ann. §35-11-319(b) |
| Louisiana | 10 | La. Stat. Ann. §30:1109 |
| North Dakota | 10 | N.D. Cent. Code §38-22-17(4) |
| Utah | 10 | Utah Code §40-11-16 |
| West Virginia | 10 | W. Va. Code §22-11B-12 |

Time periods for postinjection transfer of long-term liability for CCS projects in various states. Table sourced from: https://admin.bakerlaw.com/wp-content/uploads/2023/06/Carbon-Capture-Regulatory-handbook-CCUS.pdf.

In general, onshore projects are developing under state guidelines that suggest long-term liability will last for many decades after injection. That means operators may be liable for the integrity of $CO_2$ for a long period before liability transfers to the state. Long-term liability is even less defined for offshore settings but could be addressed by forthcoming rules from BSEE and BOEM.

Some states have taken steps to ensure that operators remain financially responsible for long-term monitoring by creating "dedicated storage funds." This has included passing legislation that directs funds from CCUS projects for this purpose via application fees, permitting or operating fees, or well closure fees. Another approach is to set the financial commitment in terms of a specified amount per metric ton of $CO_2$ injected. In 2009, Texas instituted the Anthropogenic Carbon Dioxide Storage Trust Fund to address some of the financial aspects of long-term liability, including costs for long-term monitoring and remediation, as well as adequate abandonment procedures. Other states that have adopted similar measures include Louisiana, Montana, North Dakota, and Wyoming. Dedicated funds are a way to guarantee public and environmental protection after geologic carbon storage projects have been completed.

# Costs

In general, offshore storage operations will be more expensive than onshore operations. Working in a marine environment incurs additional costs related to specialized equipment and personnel. Offshore equipment also requires more advanced management of saltwater corrosion and must tolerate potential storm conditions that can be quite severe in marine settings. In the simplest terms, it is far cheaper and faster to drive a crew to an onshore well site than taking a ship or helicopter to an offshore well site.

Costs are project specific and difficult to estimate. At some offshore sites, a $CO_2$ storage facility might incorporate engineering solutions that have not been widely deployed before and therefore have no established cost baseline. Costs for some activities that are analogous to current activities (such as onshore drilling or pipeline construction) may be reasonably predictable. Because hydrocarbon reservoirs in near-offshore areas of the Gulf Coast are depleted, few wells have been drilled in this region in recent years, making it hard to predict the cost of bringing in a jack-up rig to drill a new well. However, one jack-up rig is actively drilling in state waters off the Texas coast for the purposes of CCS development. Larger economic forces or supply chain constraints may mean that recent costs do not provide an accurate basis for projecting future costs. For example, the chrome steel needed for $CO_2$ injection wells was hard to source in 2023—production timelines were long, and costs were high. To the extent that offshore storage facilities are easier to site, permit, finance and operate, it may be faster and more economical to develop these projects compared with some onshore storage.[26]

While there is agreement that costs for CCUS will decline over time in the same way that costs have declined for most other new technologies, it will take more deployment to identify where cost reductions can occur. Learning by doing creates economies of scale for the deployment of most new technologies—as was the case with solar energy, for example. Cost declines can be expected for all aspects of CCUS, including capture, transport, storage, and monitoring as more experience is gained.

The challenges for financing $CO_2$ storage projects are similar in both onshore and offshore settings. A central issue is managing long development timelines (including a lack of revenue generation in the early development stages) when capital is at risk, while also coordinating the financing and construction of associated capture, transport, and storage infrastructure. In particular, financing for capture projects may be difficult to obtain until adequate storage has been identified. However, the need to secure participating emitters via an offtake agreement can complicate the financing of storage projects. Given the increase in storage lease positions and a lack of new capture announcements, it seems the industry is seeking to secure storage first, then integrate capture and transport. Most of the projects that are currently underway are being undertaken by entities that have experience in subsurface activities and also own emission assets.

In particular, financing for capture projects may be difficult to obtain until adequate storage has been identified.

# Synthesis and Considerations for Policymakers

Although much depends on site specifics, in general, onshore $CO_2$ storage offers advantages in terms of lower capital and operating costs, while offshore settings benefit from larger leasable areas (with larger storage potential) and a simplified leasing structure. As a result, onshore lease fees are generally higher per acre than offshore fees. Onshore regions are likely to have more legacy wells, which are also likely to be older (and potentially present higher environmental risk) than offshore regions. Finally, onshore projects can attract more public scrutiny, especially if they are near populated or environmentally sensitive areas, although requirements for documented environmental protection (and monitoring) are similar for both.

To achieve the goal of effective, long-term carbon management, continued support from policymakers and cooperation between industry and regulators are crucial to advance responsible geologic carbon storage. Several key policy issues merit further consideration.

## UNLOCKING FINANCING AND TAX CREDITS

Developers of large-scale carbon management projects will likely continue to rely heavily on the Inflation Reduction Act's (IRA) 45Q tax credit for financing. The 2022 legislation improved and updated this tax credit, but further improvements are needed to unlock financing for larger projects, including tying the credit to inflation and extending the timeline to claim the credit beyond 12 years. Many project developers could potentially leverage other financial incentives, such as the Low Carbon Fuel Standard (LCFS) credits offered in California. Many companies conduct projects in other states that could potentially qualify for such credits, although eligibility under the California program is limited to onshore geologic storage solutions. The California Legislature would have to make changes to expand the state's LCFS to recognize offshore storage for crediting purposes. In the longer term, policymakers will also need to weigh and contend with programs that address the need for integrity in the voluntary carbon market, international trading, border carbon adjustments, and carbon pricing efforts—all of which could affect the availability of private financing to develop CCUS infrastructure.

## EXPEDITING CLASS VI PERMIT APPROVALS

Reducing the time needed to permit Class VI wells—and the time to approve offshore permits, once BSEE finalizes its rules—would reduce development (timeline) risks for companies, accelerating projects and rates of $CO_2$ storage. Granting state primacy to permit Class VI wells is widely recognized as a logical step for reducing timeline risks while maintaining environmental protections. Unfortunately, the process for granting primacy has proved quite lengthy as well, although additional state and federal funding to support the process could help.

## ENSURING ROBUST OFFSHORE LEASE ARRANGEMENTS

Currently, more acreage has been leased for $CO_2$ storage offshore (in state waters) than onshore, even though no Class VI well applications are in process for offshore sites. Pending BOEM/BSEE guidance on leasing and permitting structures for geologic storage in federal waters is essential to unlocking major additions of $CO_2$ storage capacity.

## CLARIFYING LONG-TERM LIABILITY CONCERNS

Policymakers can further refine rules and definitions around long-term liability and dedicate funds to support long-term stewardship. Additional resources could also be devoted to the remediation of legacy wells. Clarifying long-term liability for geologic storage after a certain postinjection period would reduce project uncertainty and help increase public acceptance over time.

## ROBUST ANNUAL APPROPRIATIONS FOR FEDERAL ACTIVITIES RELATED TO CARBON MANAGEMENT

DOE's efforts on carbon management were turbocharged by the BIL, which included $2.5 billion for an expanded carbon storage and validation program. This funding supports efforts such as the Carbon SAFE program, which helps guide commercial-scale projects through the myriad challenges of site characterization, permitting, and analysis. DOE has also entered into a memorandum of understanding with EPA to support the processing of Class VI permits. Continued support for DOE's carbon storage research and EPA's Class VI permitting process should continue to be a priority for members of Congress and the administration in annual appropriations discussions.

BSEE and BOEM stated that the development of regulations clarifying their new authorities over $CO_2$ injection wells would be a focus for fiscal year 2025 (second only to offshore wind). Accordingly, both BOEM and BSEE have budgeted funds from FY2024 to develop such a framework. However, Interior's proposed implementing regulations, as authorized under the BIL, have yet to be issued for public comment. The first meeting of the White House Council of Environmental Quality CCS on Federal Lands Task Force occurred May 21–22, 2024. BSEE was awarded $2 million in FY2024 and is requesting $1.5 million in FY2025 to establish a Carbon Sequestration Program to implement the law's requirements. The FY2025 request will allow BSEE to actively pursue solutions for the unique challenges presented by sub-seabed $CO_2$ storage, including creating a multidisciplinary team to focus on identifying relevant industry standards and enforcement requirements; determining applied research needs and requirements; creating baseline risk assessment criteria for carbon storage projects; reviewing flow modeling; identifying conservation considerations; and instituting performance and safety standards.

# Conclusion

Carbon management technologies are expected to play an essential role in meeting net-zero emissions goals, but their deployment must accelerate in coming decades to remove atmospheric $CO_2$ at the scale needed to have a meaningful impact on climate change. In the United States and globally, countries face the unprecedented challenge of delivering abundant, affordable, and reliable energy, while rapidly and simultaneously reducing greenhouse gas emissions. Geologic storage of $CO_2$ offshore and onshore can contribute to these goals—both approaches share some commonalities, while also offering distinct advantages and disadvantages.

Decarbonization has been called the "second industrial revolution" because of its scale and impact on society. One such impact is economic. Carbon management has the potential to develop into a new industry that could eventually rival the hydrocarbon industry in scale. Many of the skills it requires have industrial analogues, especially in petroleum geoscience and engineering, which creates opportunities to absorb displaced workers and support new jobs. Moreover, the offshore environment holds tremendous potential for expanding economic carbon management. A 2012 study estimated that adding geologic $CO_2$ storage on the continental shelf could provide a cumulative net benefit to the U.S. economy of $16.9 billion between 2015-2050.[27] To unlock these benefits, stakeholders will need to address a range of technical, environmental, and social considerations for the large-scale deployment of $CO_2$ storage—both onshore and offshore.

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