MEETING THE DUAL CHALLENGE

A Roadmap to At-Scale Deployment of CARBON CAPTURE, USE, AND STORAGE

CHAPTER SEVEN – CO_2 GEOLOGIC STORAGE

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Chapter Seven

CO_2 GEOLOGIC STORAGE

I. CHAPTER SUMMARY

Storing carbon dioxide (CO_2) in deep geologic formations, for the purpose of reducing greenhouse gas (GHG) emissions, began in 1996 with the Sleipner CO_2 storage project in Norway. When Equinor (formerly Statoil) began pumping 1 million tonnes per annum (Mtpa) of CO_2 into the offshore Utsira Formation in the Sleipner gas field, it paved the way for three additional large-scale projects in Norway, the United States, and Canada. These projects collectively have stored approximately 4 Mtpa. In 2019, the Gorgon Project in Western Australia initiated injection operations into a saline formation, and when at full operation in 2020, will store between 3 to 4 Mtpa. More than 20 years after the Sleipner project was established, there is now an extensive network of global knowledge about CO_2 storage, and the United States has emerged as a world leader on the topic. As of 2019, there are currently 19 large-scale carbon capture, use, and geologic storage (CCUS) projects operating around the world with a total storage volume of about 32 Mtpa. Ten of these projects are in the United States, accounting for a total storage volume of 25 Mtpa.

Safe, secure, and permanent geologic storage of CO_2 requires the presence of a sufficiently permeable rock formation, typically sandstone or carbonate, which is sealed by rocks on top that have a very low permeability. These formations need to be 1 kilometer (km) or deeper to ensure that the CO_2 is stored as a dense phase, also called a supercritical fluid. To protect underground drinking water aquifers, CO_2 storage is only permitted in saline formations that are saltier than 10,000 parts per million (ppm) total-dissolved-solids per the United States Environmental Protection Agency (EPA) Class VI Underground Injection Control (UIC) regulations. The geologic seal, typically a shale formation, must be continuous over the entire area where the CO_2 is stored and free of defects such as permeable faults, fractures, or leaky wellbore penetrations.

The CO_2 storage capacity estimates for the United States have been assessed by both the United States Department of Energy (DOE) and the United States Geological Survey (USGS). Both assessments indicate a very large potential for storage, with median estimates ranging from 3,000 to 8,600 billion metric tons (called gigatonnes or Gt) of CO_2. The economic potential, often referred to as a "storage reserve" is likely to be significantly lower, but how much lower is not known yet. Even conservative estimates are very large compared to the ~5 Gt CO_2/year emitted in the United States—of which about 50% or ~2.5 Gt CO_2/year is associated with large-scale stationary emissions sources—suggesting that storage capacity is unlikely to be a limiting factor in the United States. Other factors, such as access to CO_2 pipelines for transport, capture economics, public support, and local injectivity constraints, are likely to pose a greater challenge to at-scale deployment of CCUS in the United States.

Prospective geologic formations for CO_2 storage require adequate storage capacity, sufficient permeability, and a high-quality geologic seal. Additional considerations include an assessment of the risks of induced seismicity and the potential for CO_2 or brine leakage through preexisting boreholes. Brine is another term for saline water that naturally exists in a rock formation.

Cost estimates that include both capital expenditures and operating costs for storage in saline formations range from \$1 to \$18 per tonne of CO_2 (tCO_2) in 2013 dollars. For most sites in the United States, DOE estimates narrow the range from \$7 to \$13/tCO_2. The wide range reflects the site-specific nature of geologic storage projects. In 2019, preliminary cost estimates for storage sites in the Southeastern United States, which has excellent geologic conditions for storage, were as low as \$3/tCO_2.[1] Storage cost is primarily affected by the depth of the formation, volume of CO_2 to be stored, number of injection wells required, purity of the CO_2 stream, existing land uses, and ease of deploying surface and subsurface CO_2 monitoring programs.

In the United States, underground storage of CO_2 is regulated by the EPA's UIC Program. Regulations for Class VI CO_2 storage wells were finalized in 2010. Six permits have been issued, but only two permits are active, both in Illinois, and only one of those permits is currently in active injection operations. Four permits were issued for the FutureGen 2.0 project in Illinois, but these were never used because the project was funded through the American Reinvestment and Recovery Act, which expired in 2015 before the project could be completed.

This chapter explains the following topics:

- Description of CO_2 geologic storage
- Current knowledge about geologic storage, including its costs and existing projects
- Geologic storage options and capacities in conventional and unconventional onshore conventional offshore formations, and depleted oil and natural gas fields
- Description of what is needed to enable at-scale deployment including incentives, access to onshore federal lands and offshore leases, and clarifying legal issues
- Issues that affect both CO_2 enhanced oil recovery (EOR) and CO_2 geologic storage
- Research and development needed to accelerate CO_2 storage.

In 2018, the National Academies of Science, Engineering, and Medicine completed a report on the key research needs associated with negative emissions technologies and secure sequestration (storage) of CO_2.[2] This chapter also acknowledges the findings from that report.

II. WHAT IS CO_2 GEOLOGIC STORAGE?

A. Describing CO_2 Storage

Carbon capture, use, and storage, including transport, combines processes and technologies to reduce the level of CO_2 emitted to the atmosphere or remove CO_2 from the air. These technologies work together to capture (separate and purify) CO_2 from stationary sources so that it can be compressed and transported to a suitable location where the CO_2 is converted into usable products or injected deep underground for safe, secure, and permanent storage. Figure 7-1 is a schematic showing the CCUS technologies.

Geologic storage refers to the process by which CO_2 is pumped underground into rocks such that it is permanently trapped so it cannot return to the atmosphere. The key to achieving this is identifying geologic formations that have two specific properties.

First, the formation rock must have sufficient pore space (porosity) in which CO_2 can be contained for storage and pathways connecting the pore space (permeability) so the CO_2 can be injected into and move within the formation. About 73% of the rocks on the Earth's surface meet these criteria. These are sedimentary rocks that were formed when small grains of sediment accumulated on seashores, deltas, ocean floors, riverbeds, and lakes over millions of years. Eventually the sediments were buried and became sandstone, which is largely

1 Esposito, R. A., Kuuskraa, V. A., Rossman, C. G., and Corser, M. C., "Reconsidering CCS in the U.S. fossil-fuel fired electricity industry under section 45Q tax credits," *Greenhouse Gas Science & Technology*, 0:1–14 (2019), doi: 10.1002/ghg.1925.

2 National Academies of Sciences, Engineering, and Medicine. (2019). *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda.* Washington, DC: The National Academies Press: https://doi.org/10.17226/25259.

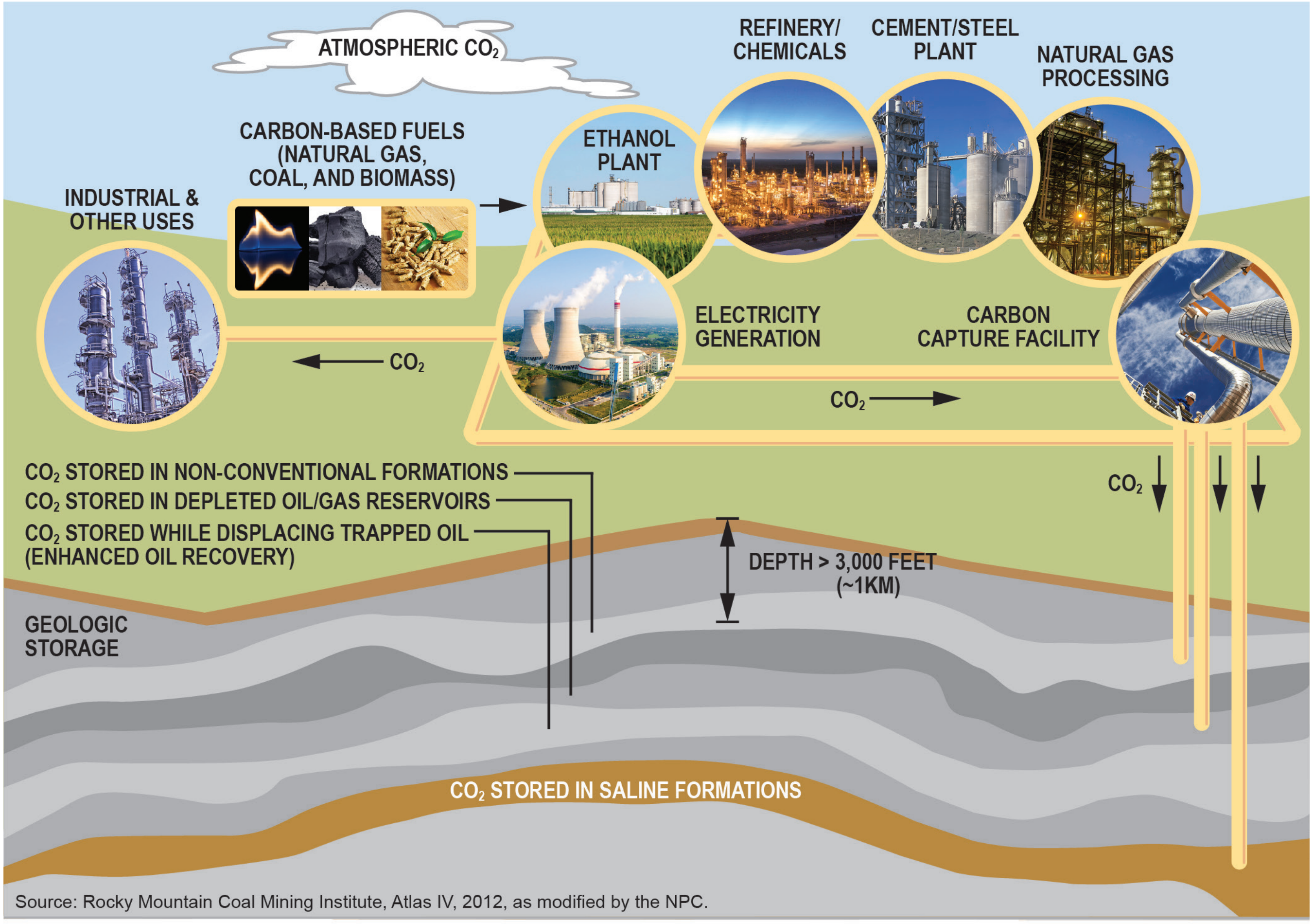
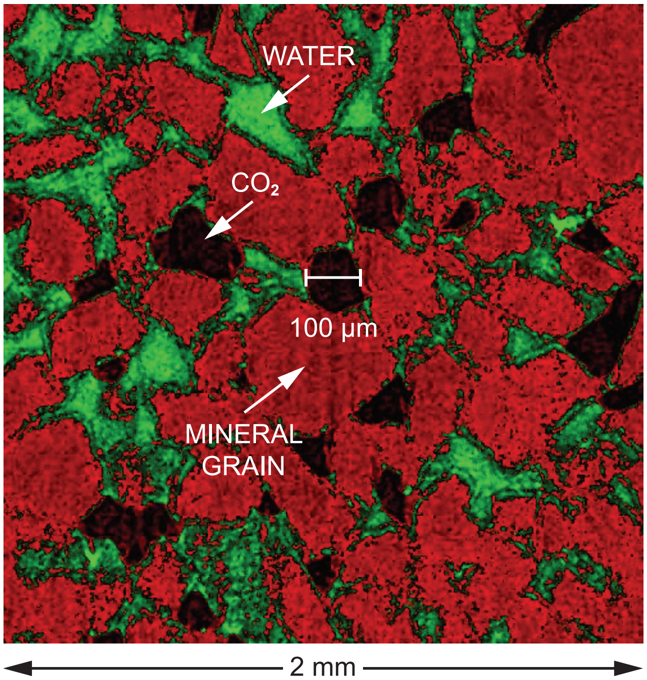


Figure 7-1. *Supply Chain for Carbon Capture, Use, and Storage*

composed of quartz grains, or carbonates, which results from the accumulation of small marine organisms and shells. Although sandstones and carbonates appear to be solid rock, they are filled with small void spaces called pores. When these types of rock are about a mile or more below the surface, under normal conditions the pores are filled with salty water, which is why they are called saline formations. Pushing the water out of the way, and filling the pore spaces with CO_2 instead, enables the storage of large volumes of CO_2. Figure 7-2 shows a microscopic image of the rocks in a saline formation storing CO_2. The rock grains are red, pore spaces filled with water are green, and pore spaces filled with CO_2 are black. Typically, 10% to 25% of the rock volume is made up of pores. A discussion of the potential capacity for storing CO_2 in sandstone and carbonate rocks is found in Section IIIA, Storage Options in Conventional Geologic Formations.

The storage formations must be deep enough so that the natural pressure and temperature can maintain the CO_2 as a dense fluid, also called a supercritical fluid or state. Typically, the minimum depth required for this temperature and pressure are greater than or equal to about 3,000 feet (about 1 kilometer or 0.56 miles) depending on geothermal gradient. To protect underground drinking water aquifers, CO_2 storage is only permitted in saline formations that are saltier than 10,000 ppm Total Dissolved Solids (TDS) per EPA Class VI UIC regulations.

Second, a prospective storage reservoir must have a geologic seal above it. The sedimentary rock of a geologic seal must have a very low permeability that prevents CO_2 from leaving the storage formation. Seals are often made up of clay (shale), salt, or carbonate rocks with pores that are too small to enable the CO_2 to enter or pass through them.



Source: Silin, D., Tomutsa, L., Benson, S. M., and Patzek, T. W. (2011). "Microtomography and pore-scale modeling of two-phase fluid distribution." Transport in Porous Media, 86 (2), 495-515.

Figure 7-2. *Microscopic Image of Sandstone Showing Mineral Grains and Pore Spaces Filled with Water or CO_2*

When CO_2 is injected into the formation rock, it displaces some of the saline water—also called brine—in the formation, causing the reservoir's fluid pressure to increase. The pressure buildup increases the density of the brine and pore volume of the rock, making space in the reservoir to accommodate the incoming volume of CO_2. The magnitude of pressure buildup depends on the CO_2 injection rate, rock properties such as permeability, and the size of the storage reservoir. For large reservoirs with high permeability, the pressure buildup is small and does not present any storage safety concerns by damaging the reservoir and causing CO_2 leakage. In contrast, in a small, completely sealed reservoir, the pressure buildup may be rapid and large. A large pressure buildup would damage the geologic seal that sits on top of the storage formation, preventing fluids from escaping the reservoir. Avoiding damage to this seal requires limiting the rate of injection or extracting some of the displaced brine while the CO_2 injection is taking place. When CO_2 injection stops, reservoir pressure will gradually decrease until it returns to its pre-injection level.

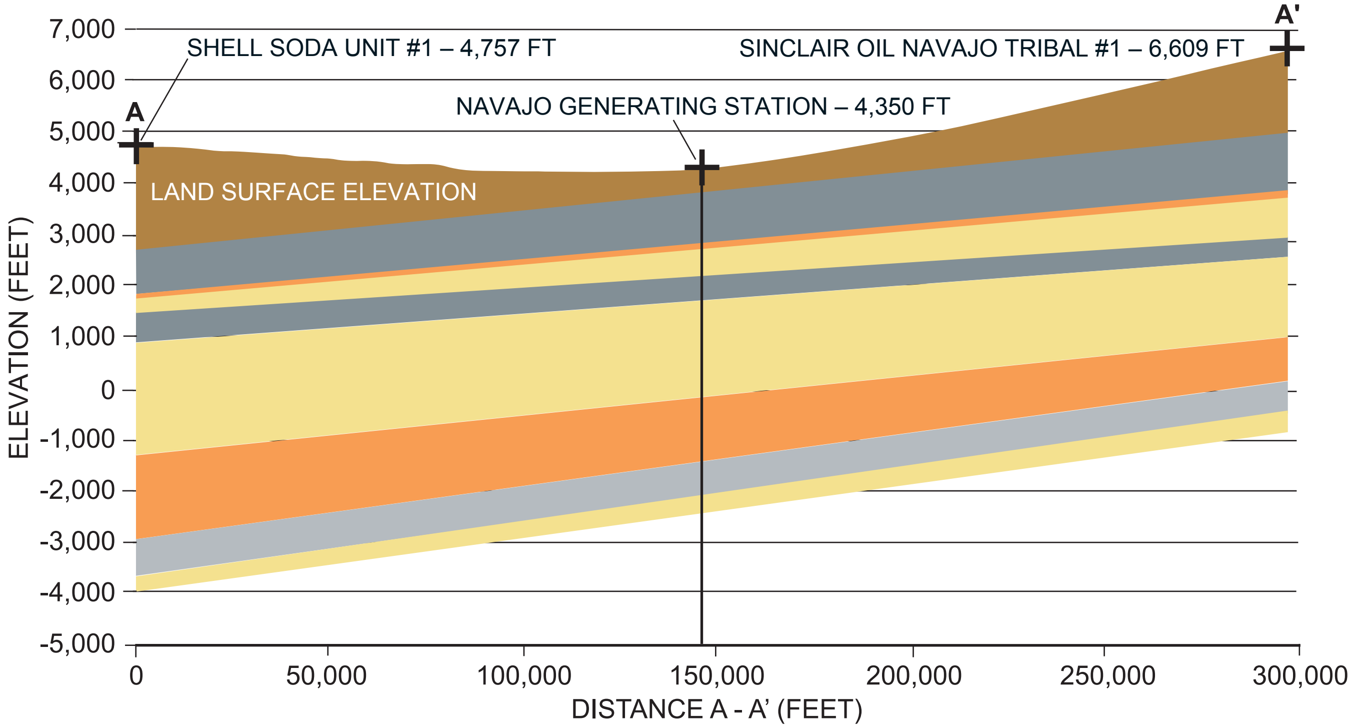
Sandstone reservoirs with alternating layers of porous and permeable rock, sitting below a low-permeability geologic seal(s), are ideal for storing large volumes of CO_2 (Figure 7-3) because of their layered geology. These types of formations occur naturally and are rather prolific in the United States. When CO_2 storage operators select a reservoir, the goal is to identify one that has enough storage capacity (volume) to accommodate all the CO_2 that needs to be stored and has an extensive seal to ensure safe, secure, and permanent storage.

The Earth's naturally occurring geology provides the oldest proof that large quantities of CO_2 can be safely and securely trapped underground for millions of years. In 2005, the United Nations Intergovernmental Panel on Climate Change concluded that, "The widespread presence of oil, gas, and CO_2 trapped in formations for many millions of years implies that within sedimentary basins, impermeable formations—called caprocks—of sufficient quality to confine CO_2 for geologic time periods are present."[3] And in Mississippi, the CO_2 trapped in the Pisgah Anticline northeast of the Jackson Dome is thought to have been emplaced more than 65 million years ago.[4] This example is one among several deposits of natural CO_2 that exist in the United States and around the world, demonstrating that naturally occurring reservoir seals exist and are able to confine CO_2 for millions of years.

When compared to millions of years, the 100 years of intentional, underground storage of gases and liquids due to human activities is a relatively recent development. Humans have been storing natural gas securely in depleted oil and natural gas reservoirs and other formations for more than 40 years. Natural gas storage reservoirs are also good analogues for CO_2 storage and demonstrate that injected gas can be

3 United Nations Climate Change Conference (2005) in Montreal, Quebec, Canada.

4 Studlick, J. R. J., Shew, R. D., Basye, G. E., and Ray, J. R. (1990). "A giant carbon dioxide accumulation in the Norphlet Formation, Pisgah Anticline, Mississippi," 181-203, in Barwis, J. H., McPhearson, J. G. and Studlick, J. R. J. (eds.), *Sandstone Petroleum Reservoirs*, Springer-Verlag, New York.



Source: Benson, S. M. and Cole, D. R. (2008). "CO2 Sequestration in Deep Sedimentary Formations." *Elements*, vol. 4, pp. 325-331.

Figure 7-3. *The Layered Geology of Sandstone (yellow) Below Shale Seals (grey) that Enables CO_2 Storage*

stored underground safely. Natural gas storage is used as a buffer between natural gas supply and demand. In 2019, there were more than 400 natural gas storage facilities operating in the United States and Canada with a total storage capacity exceeding 160 Mt.[5]

B. CO_2 Storage Projects Around the Globe

There have been several CCUS research programs conducted in Europe, the United States, Canada, Australia, and Japan since 1990. The global body of knowledge about CO_2 storage has been gleaned from these early commercial and demonstration carbon capture and storage (CCS) projects, including:

- Sleipner project, Norway: ~1 Mtpa stored, began in 1996
- Snøhvit project, Norway: ~0.8 Mtpa stored, began in 2008
- Frio pilot, United States: ~1.6 kilotonnes (Kt) stored 2004–2009
- Illinois-Decatur project, United States: ~1 Mtpa stored 2011–2014
- In Salah project, Algeria: ~1 Mtpa stored 2004–2011
- Ketzin project, Germany: ~70 Kt stored 2008–2014
- Plant Barry CCS project, United States: ~115 Kt stored 2012–2014
- Otway project, Australia: 15 Kt stored 2015–2016
- Aquistore project, Canada: ~110 Kt stored 2015–2017
- Lacq project, France: 51 Kt stored 2010–2013
- Tomakomai project, Japan: ~200 Kt stored 2016–2018
- Quest project, Canada: 1 Mtpa stored since 2015
- Illinois Industrial project, United States: 1 Mtpa stored since 2017

5 Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L. (eds.), *Carbon Capture and Storage*, IPCC, 2005 – Special Report, Cambridge University Press, UK, p. 431.

- Gorgon LNG project, Australia: injection operations started in 2019, increasing to 3 to 4 Mtpa in 2020.

International collaborations facilitated by organized networks such as the IEA Greenhouse Gas R&D Programme, Global CCS Institute, Carbon Sequestration Leadership Forum, and CO_2GeoNet were instrumental to creating a global scientific community dedicated to CO_2 storage.

C. Commercial CO_2 Injection Projects

Injection of CO_2 in the subsurface began in the 1960s with CO_2 EOR operations, many of which were in the United States. CO_2 injection is a common process applied in several industries, including oil and natural gas production, natural gas and hydrogen storage, municipal wastewater disposal, waste management, geothermal energy production, and aquifer recharge. The CO_2 injection process used across different industries is based on similar concepts and technologies and addresses similar technical and non-technical challenges.

Commercial storage projects in deep saline formations around the globe include Snøhvit in the North Sea and Aquistore in Canada, which operate at lower injection rates or intermittently. Chevron began CO_2 injection at the Gorgon Project on Barrow Island off the coast of Western Australia in 2019. When the project reaches full capacity of 3 to 4 Mtpa in 2020, it will be the largest commercial storage project in the world. Another commercial-scale operation that is no longer actively injecting CO_2 is the In Salah project in Algeria.

The projects highlighted in this section include offshore (Sleipner in Norway) and onshore (Illinois Industrial CCS and Quest in Canada) saline formation storage examples. The CO_2 for these projects is sourced from a variety of industrial activities, including natural gas processing, bioethanol fermentation, and heavy oil upgrading. Each project injects about 1 Mtpa of CO_2 into sandstone reservoirs.

1. Sleipner CCUS Project, Norway

Commercial CO_2 storage in deep saline formations was first implemented at the Sleipner CCUS project in Norway in 1996.[6] Sleipner is an offshore, platform-based CO_2 capture facility that is part of the Sleipner gas and condensate field development located approximately 155 miles (250 km) offshore southern Norway. The CO_2 stream at Sleipner is derived from natural gas processing and uses a solvent-based absorption, post-combustion capture process that is explained in Chapter 5, "CO_2 Capture." The Sleipner project has integrated commercial-scale CCUS with conventional oil and natural gas field development operations.

The CO_2 is injected and stored in the Utsira Formation about 0.6 mile (1 kilometer) below the seabed. By 2018, the Sleipner project had stored more than 17 Mt of CO_2 at an average annual injection rate of about 0.9 Mt/year. More recently, the Sleipner project began storing CO_2 captured from neighboring gas fields, giving it CCUS hub status.[7] Monitoring storage site performance and assuring safe containment through monitoring has been achieved through a series of time-lapse seismic data sets. These data sets provide important insights into the value and detection capabilities of remote geophysical monitoring methods.[8] The 23-year performance history at Sleipner is a testament to the value of careful well design and engineering.

2. Illinois Industrial Carbon Capture Project

The Illinois Industrial Carbon Capture and Storage project (IL-ICCS), led by the Archer Daniels Midland Company (ADM), is demonstrating an integrated system for collecting and geologically storing up to 3,000 tonnes/day of CO_2 from ADM's bioethanol plant in Decatur, Illinois. The CO_2 is captured at atmospheric pressure and high

6 Baklid, A., Korbol, R., and Owren, G. (1996). "Sleipner Vest CO_2 disposal, CO_2 injection into a shallow underground aquifer." In *SPE Annual Technical Conference and Exhibition*, Society of Petroleum Engineers.

7 Ringrose, P. S. (2018). "The CCS hub in Norway: some insights from 22 years of saline aquifer storage," *Energy Procedia*, vol. 146, 166-172.

8 Chadwick, A., Williams, G., Delepine, N., Clochard, V., Labat, K., Sturton, S., and Arts, R., "Quantitative analysis of time-lapse seismic monitoring data at the Sleipner CO_2 storage operation," *The Leading Edge*, 29(2) (2010): 170-177.

purity—greater than 99% purity on a moisture-free basis—from ADM's corn-to-ethanol fermenters. The CO_2 stream is compressed, dehydrated, and delivered by an 8-inch diameter, 1-mile long pipeline to the injection wellhead.

The IL-ICCS project holds the first EPA UIC permit to operate a Class VI injection well. Injection of CO_2 at the IL-ICCS project uses a single injection well and began injection operations in April 2017. The site was designed to inject 3,000 tonne/day to meet an annual storage target of 1 Mt. The monitoring of injected CO_2 is performed within the Mount Simon Sandstone injection zone and above the storage reservoir by verification wells using geophysical surveys, pressure-temperature (P/T) sensors, and geochemical sampling. Shallow, environmental monitoring is ongoing and includes assessing groundwater via geochemical sampling and P/T monitoring, soil resistivity, and near-infrared aerial imagery.

3. Quest Project, Alberta Canada

The Quest Project owned by Shell Canada captures CO_2 produced at the Scotford Upgrader near Edmonton and then compresses, transports by pipeline, and injects the CO_2 for permanent onshore storage in a saline formation near Thorhild, Alberta. Shell completed drilling three wells about 1.2 miles (1.9 km) deep during 2012 and 2013 for the injection operations phase of the project. Injection began in two of the wells in 2015. Up to 1.2 Mtpa of CO_2 is being captured and there has been limited pressure buildup within the reservoir. Post-injection startup, monitoring, and verification activities have shifted to operational monitoring. Monitoring data indicates that no CO_2 has migrated outside of the injection reservoir to date.

III. STORAGE OPTIONS

Geologic storage of CO_2 requires injecting captured CO_2 into a subsurface formation that has enough porosity and permeability to store and transmit fluids. In addition, CO_2 needs to be injected into reservoirs where it can be permanently contained to prevent migration above and beyond the storage area.

In this study, CO_2 storage reservoirs are divided into conventional and unconventional reservoirs. Conventional formations have rock and fluid characteristics that enable gas and fluid to easily flow to or from wellbores drilled into the formation. The rock types that typically facilitate this include sandstone, limestone, dolomite, or a mixture of these rock types.[9]

Unconventional formations include a collection of rock types such as shale, and low-permeability (tight) sandstones, and some carbonates. Other possible subsurface CO_2 storage options include coal beds and basaltic and ultramafic rocks. Table 7-1 estimates the total technical storage capacity by type of formation in the United States, which was developed as part of DOE and USGS investigations. Median estimates for the technical storage potential in the United States range from about 3,000 to 8,600 Gt CO_2.[10]

The values in Table 7-1 are the technical potential for storing CO_2 and do not consider economic factors, risks of induced seismicity, or other constraints on the practicality of injecting CO_2 at commercial rates. Practical estimates of storage capacity were developed that considered whether sufficiently high rates of injection could be achieved, the proximity to faults, a lack of surface access, and if the presence of very thin sands makes injection more costly. Figure 7-4 illustrates the impact of each factor on reducing the practical storage capacity that could be available. The two most significant factors are reductions caused by limitations on the injection rate (40% reduction) and the presence of thin sands (20% reduction).

9 Benson, S. et al. (2005). "Underground geologic storage," in Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L., eds., *Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage*, Cambridge, UK: Cambridge University Press, p. 195–276, https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/.

10 U.S. Department of Energy, National Energy Technology Laboratory. (2015). *Carbon Storage Atlas* (5th ed.; Atlas V) (DOE/NETL-2015/1709): 113 p., https://www.netl.doe.gov/research/coal/carbon-storage/natcarb-atlas.

U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). "National assessment of geologic carbon dioxide storage resources—Results" (ver. 1.1, September 2013), U.S. Geological Survey Circular 1386, 41 p., http://pubs.usgs.gov/circ/1386/.

Type of Geologic Formation	Low ($Gt\ CO_2$)	Median ($Gt\ CO_2$)	High ($Gt\ CO_2$)	Source(s)
Conventional Onshore	2,379	8,328	21,633	National Energy Technology Laboratory (NETL) Carbon Storage Atlas (2015)*
	2,300	2,984	3,700	USGS (2013)[†]
Conventional Offshore	n/a	n/a	1,000	Southern States Energy Board (2013)[‡]
Shale	28[§]	134[¶]	171[#,**]	Nuttall et al. (2005),[§] Godec et al. (2013a),[¶] Godec et al. (2013b)[#]
Coal Beds	54	80	113	NETL Carbon Storage Atlas (2015)*
Basalt	n/a	n/a	n/a	
Depleted Oil and Natural Gas Reservoirs	190		230	NETL Carbon Storage Atlas (2015)*

* U.S. Department of Energy, National Energy Technology Laboratory. (2015). Carbon Storage Atlas (5th ed.; Atlas V) (DOE/NETL-2015/1709): 113 p., https://www.netl.doe.gov/research/coal/carbon-storage/natcarb-atlas.

† U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). "National assessment of geologic carbon dioxide storage resources—Results." (ver. 1.1, September 2013): U.S. Geological Survey Circular 1386, 41 p., http://pubs.usgs.gov/circ/1386/.

‡ Southern States Energy Board. (2013). "Preliminary Evaluation of Offshore Transport and Geologic Storage of Carbon Dioxide," https://www.sseb.org/wp-content/uploads/2010/05/Offshore-Study-full2.pdf.

§ Nuttall, B. C., Eble, C. F., Drahovzal, J. A., and Bustin, M. R. (2005). Analysis of Devonian black shales in Kentucky for potential carbon dioxide sequestration and enhanced natural gas production: Kentucky Geological Survey Final Report to U.S. Department of Energy, 120 p.

¶ Godec, M. L., Jonsson, H., and Basava-Reddi, L. (2013a). "Potential global implications of gas production from shales and coal for geological CO_2 storage." *Energy Procedia*, vol. 37, 6656-6666.

\# Godec, M., Koperna, G., Petrusak, R., and Oudinot, A. (2013b). "Assessment of factors influencing CO_2 storage capacity and injectivity in eastern U.S. gas shales," GHGT-11, *Energy Procedia*, vol. 37, 6644-6655.

** Benson, S., et al. (2005). "Underground geologic storage," in Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L., eds., Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage, Cambridge, UK: Cambridge University Press. p. 195–276, https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/.

Table 7-1. *Storage Capacity Estimates for Different Geologic Formations in the United States*

Although practical storage capacity estimates are lower than previously published technical estimates, onshore subsurface storage capacity in the United States is enough to sustain a large-scale CO_2 storage industry. Different types of formations have different technical and practical storage capacity estimates due to differing reservoir properties. It is estimated that approximately 500 Gt of storage capacity in the United States is practically available today in reasonable proximity to CO_2 emissions sources or transport infrastructure[11] (see Chapter 2, "CCUS Supply Chains and Economics," in Volume II of this report).

11 Teletzke, G. F., Palmer, J. J., Drueppel, E., Sullivan, M. B., Hood, K. C., Dasari, G. R., and Shipman, G. W. (2018). "Evaluation of Practicable Subsurface CO_2 Storage Capacity and Potential CO_2 Transportation Networks, Onshore North America," GHGT-14, Melbourne, Australia.

A. Storage Options in Conventional Geologic Formations

1. Definition of Conventional Reservoirs

After CO_2 is captured, it needs to be compressed into a dense, liquid-like state called a supercritical fluid so it can be transported and injected into a formation. Compressing the captured CO_2 gas to a supercritical fluid enables more CO_2 to be stored because it has a higher density compared with gaseous CO_2.[12] In the United States, fresh subsurface sources of drinking water are protected by the Safe Drinking Water Act.

12 Benson, S., et al. (2005). "Underground geologic storage," in Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L., eds., *Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage*, Cambridge, UK: Cambridge University Press. p. 195–276, https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/.

To be suitable for conventional storage of CO_2, the geologic formations must have an impermeable regional seal or series of seals (Figures 7-1 and 7-3). CO_2 in a supercritical fluid state is less dense than the fluids that initially fill the pore spaces in the rock. Hence after injection, the CO_2 slowly rises by buoyancy forces through the reservoir rocks until it encounters a low-permeability primary geologic seal. The sealing formations prevent CO_2 stored in the reservoirs from migrating into shallower groundwater aquifers, or to the surface where it could be released to the atmosphere. Once trapped below the primary seal, the CO_2 will remain permanently stored unless a mobile CO_2 plume encounters a permeable fault or fracture in the seal or a leaky wellbore.[13] However, this type of complication has not occurred at any of the CO_2 storage sites listed in the section on CO_2 Storage Projects around the globe, and careful site selection is the reason why it has not. Although primary geologic seals are important to retaining injected CO_2 underground, there are other mechanisms for immobilizing CO_2 to prevent leakage.

13 National Academies of Sciences, Engineering, and Medicine. (2018). *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda.* Washington, DC: The National Academies Press, 356 p., https://org/10.17226/25259.

2. CO_2 Trapping in Conventional Reservoirs

Storage of CO_2 in conventional formations can use one of several trapping processes—buoyant, residual, solubility, and mineral.[14] In buoyant trapping, CO_2 generally flows upward slowly until it is immobilized in a stratigraphic or structural trap formed by the geologic seal (also called caprock), lateral seals, sealing faults, or other seals (Figure 7-4).[15] Residual trapping occurs as small droplets of CO_2 are left behind during the migration of a CO_2 plume through the porous reservoir rock. These droplets are trapped in the

14 Benson, S. M., and Cole, D. R. (2008). "CO_2 Sequestration in Deep Sedimentary Formations," *Elements*, vol. 4, pp. 325-331, doi: 10.2113/gselements.4.5.325.

15 Brennan, S. T., Burruss, R. C., Merrill, M. D., Freeman, P. A., and Ruppert, L. F. (2010). "A probabilistic assessment methodology for the evaluation of geologic carbon dioxide storage," U.S. Geological Survey Open-File Report 2010–1127, http://pubs.usgs.gov/of/2010/1127.

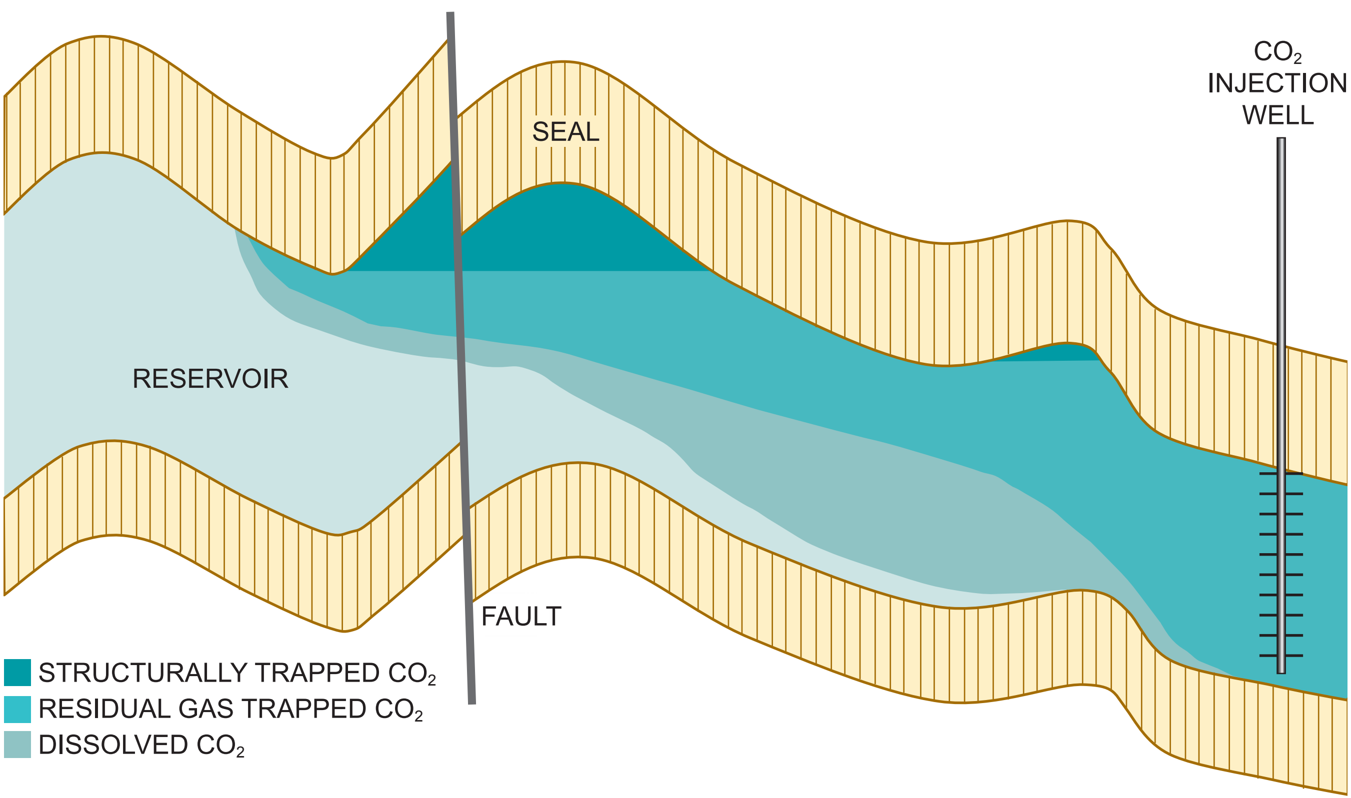


Figure 7-4. *How CO_2 Is Trapped in a Storage Formation*

rock's pore spaces by interfacial (surface) tension. Solubility trapping dissolves 10% to 25% of the CO_2 almost instantly when it is injected into the formation. When injection stops, the CO_2 will continue to dissolve very slowly due to the convective mixing of dissolved CO_2 with the brine in the storage formation. For siliciclastic[16] (sandstone) reservoirs with a significant fraction of calcium, magnesium, and iron-rich minerals (e.g., feldspar and clay minerals), CO_2 mineral trapping may also occur over time (from years to decades) when the injected CO_2 dissolves into the reservoir fluids and reacts with the formation rock.

The minimum depth requirement of 3,000 feet (>900 meters) for a storage formation ensures that CO_2 is compressed in a supercritical state, which minimizes storage volume. CO_2 can be stored at depths greater than 13,000 feet (>4,000 meters) if favorable reservoir conditions exist. The lateral limit of the storage formation is defined by the location where the top of the storage formation reaches the defined depth limit.[17]

Mineral trapping is generally considered to be the slowest form of trapping in sandstone reservoirs. However, injection projects in the Columbia River and in Iceland have indicated that mineralization of CO_2 in basalts can take place much faster than previously believed—on the order of years. These findings have been documented in a 2013 USGS report[18] and by the projects themselves.

3. CO_2 Storage Resource Estimates for Conventional Reservoirs

National assessments of CO_2 storage resources have been conducted by several organizations. Most notable is the 2013 assessment by the USGS Geological Carbon Dioxide Storage Resources Assessment Team, and one in 2015 by the DOE's National Energy Technology Laboratory (NETL). These assessments indicate that the United States may have mean or median total technical storage resources ranging from 3,000 to 8,600 Gt.

However, not all these resources are available for storing CO_2 due to reservoir pressure management considerations if large-scale CO_2 injection and storage is adopted nationwide (Figure 7-5).[19] Revised CO_2 storage resource estimates that include reservoir pressure management considerations is an area of ongoing research. Beyond overall regional storage capacity estimates, significant work has been performed with site-specific source-to-sink capacity estimates between Alabama Power's Plant Barry and Citronelle Dome.[20]

The injectivity calculation in Figure 7-5 assumes that wells are far enough apart to avoid any pressure interference between the wells. If the wells are closer together, pressure interference between wells may limit injectivity.[21] As such, the injection capacity per well and storage capacity per basin cited should be considered maximum values. In addition, these represent average values for an entire formation; within a given formation, injectivity will be higher and lower than the values shown.

4. Challenges Associated with Storage Projects in Conventional Reservoirs

In 2018, the National Academies of Sciences, Engineering, and Medicine (NASEM) noted that in order to meet GHG reduction goals and limit the impact on global temperatures, the nations of the world need to capture and store at least 5 to 10 Gt of CO_2 per year in deep sedimentary formations. Besides the enormous infrastructure scale-up issues associated with such an

16 Benson and Cole. (2008).

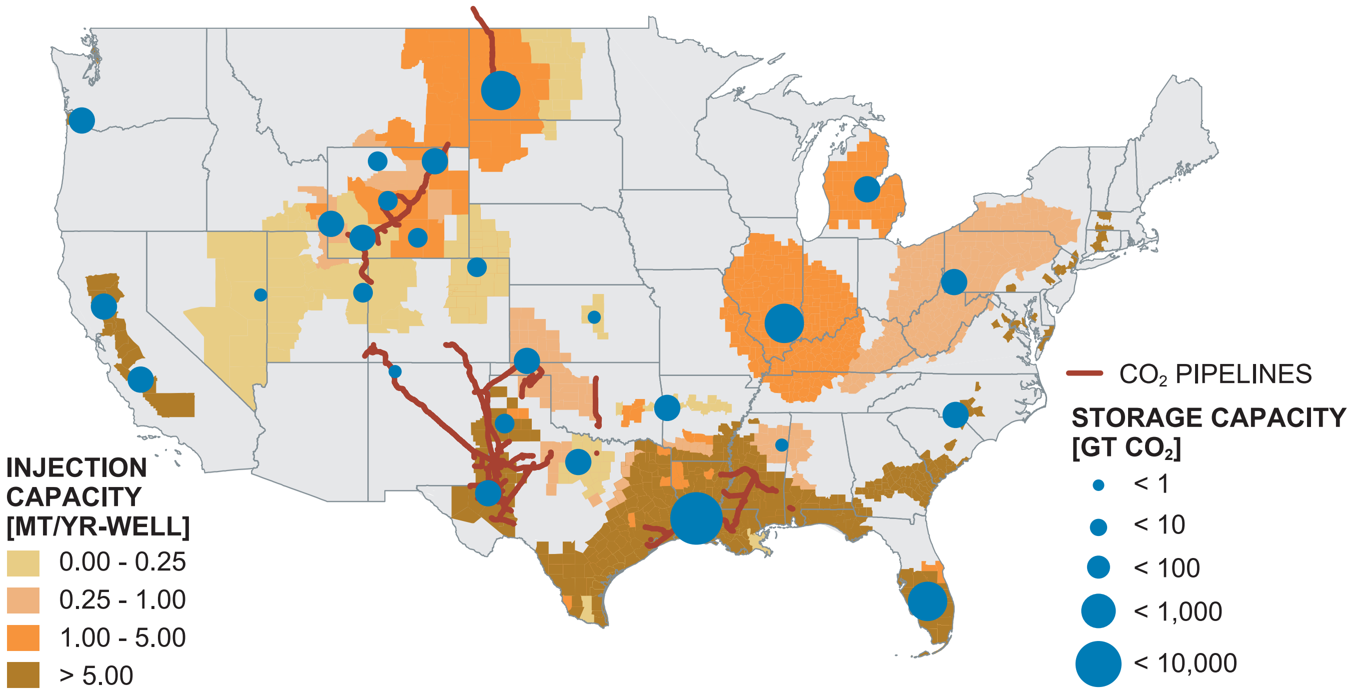
17 Blondes, M. S. et al. (2013). "National assessment of geologic carbon dioxide storage resources—Methodology implementation: U.S. Geological Survey Open-File Report 2013–1055, http://pubs.usgs.gov/of/2013/1055/.

18 U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). "National assessment of geologic carbon dioxide storage resources—Results" (ver. 1.1, September 2013): U.S. Geological Survey Circular 1386, http://pubs.usgs.gov/circ/1386/.

19 Baik, E. et al. (2018). "Geospatial analysis of near-term potential for carbon-negative bioenergy in the United States." *Proceedings of the National Academy of Sciences*, 115(13), 3290-3295.

20 Esposito, R. A., Pashin, J. C., and Walsh, P. M., "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," *Environmental Geosciences*, 2008, 15(2), 1-10.

21 Jahediesfanjani, H., Warwick, P. D., and Anderson, S. T. (2018). "Estimating the pressure-limited CO_2 injection and storage capacity of the United States saline formations—Effect of the presence of hydrocarbon reservoirs," *International Journal of Greenhouse Gas Control*, v. 79, p. 14-24, https://doi.org/10.1016/j.ijggc.2018.09.011.



Source: Baik, E., et al. (2018). "Geospatial analysis of near-term potential for carbon-negative bioenergy in the United States." Proceedings of the National Academy of Sciences, 115(13), 3290-3295.

Figure 7-5. *CO_2 Injectivity per Well and Storage Capacity in the United States*

undertaking, more research is needed to better manage how CO_2 storage projects in the same basin would interact with each other, both the CO_2 plumes and resulting pressure buildup (see Figure 7-9 in the Research and Development Needs section later in this chapter). Some of the research topics associated with geologic storage projects that NASEM identified in the 2018 report include:

- Quantifying and managing the risks of induced seismicity associated with subsurface injection of CO_2
- Increasing CO_2 injection site selection and characterization methods
- Improving the effectiveness of CO_2 injection site monitoring and lowering costs for monitoring and CO_2 storage verification
- Improving performance of trapping mechanisms and accelerating speed in trapping CO_2
- Developing reservoir engineering approaches for co-optimizing CO_2 EOR and associated CO_2 storage
- Assessing and managing risk in compromised or leaky CO_2 storage systems
- Improving simulation models for CO_2 storage performance prediction and confirmation
- Social sciences research for improving stakeholder engagement and informing the public about the need, opportunity, risks, and benefits of CO_2 storage in geologic formations.

5. Storage Costs in Conventional Formations

Costs for CO_2 storage have been estimated based on existing projects and cost models for various scenarios.[22] Estimates range from $1 to $18 per tCO_2 in 2013 dollars (Table 7-2). The most recent estimates from DOE in 2014 narrow the range from $7 to $13 per tCO_2, but several projects in the southeastern United States have documented total storage costs in the range of $3 to $6 per tCO_2.[23] The wide range reflects the highly

22 Rubin, E. S., Davidson, J. E., and Herzog, H. J. (2015). "The Costs of CO_2 Capture and Storage," *International Journal of Greenhouse Gas Control*, http://dx.doi.org/10.1016/j.ijggc.2015.05.018.

23 Esposito, R. A., Kuuskraa, V. A., Rossman, C. G., and Corser, M. C. (2019). "Reconsidering CCS in the U.S. fossil-fuel fired electricity industry under section 45Q tax credits," *Greenhouse Gas Science & Technology*, 0:1–14 (2019); DOI: 10.1002/ghg.1925.

Study	Low Estimate (2013\$/tCO_2)	High Estimate (2013\$/tCO_2)
United Nations Intergovernmental Panel on Climate Change (2005)	1	12
Zero Emission Platform (2011)	2	18
U.S. Department of Energy (2014)	7	13
Global Carbon Capture Storage Institute (2011)	6	13

Source: Rubin, E. S., Davidson, J. E., Herzog, and H. J., "The Cost of CO2 Capture and Storage," International Journal of Greenhouse Gas Control, September 2015.

Table 7-2. *Total Costs for CO_2 Storage in Geologic Formations from Different Studies*

site-specific nature of geologic storage projects. Primary variables include the depth of the formation, number of injection wells required, existing land uses, and ease of deploying monitoring programs. Costs include well drilling, injection, monitoring, maintenance, reporting, land acquisition and permits, and other incidental costs. They do not include costs associated with remediation activities that may be required in the case of well leakage, groundwater contamination, or managing the risks of induced seismicity with active pressure management.[24] Proper design and operations should avoid these complications, thus the costs associated with remediation are not included in these estimates.

In 2017, the NETL developed the FE/NETL CO_2 Saline Storage Cost Model, an open-source spreadsheet model for estimating the cost of storing CO_2 in saline formations.[25]

It is important to note that in the United States under the current EPA UIC Class VI regulatory regime for CO_2 storage, the storage operator must demonstrate financial assurance that certain specific activities can be conducted even if the operator were to become financially insolvent. These specific activities include being able to close injection wells properly at the end of CO_2 injection and to perform post-injection site monitoring and closure activities.

B. Storage in Unconventional Reservoirs

Unconventional reservoirs comprise low-permeability (tight) rocks containing hydrocarbons, rocks that may require horizontal drilling and hydraulic fracturing to enable commercial oil and natural gas production. These reservoirs have permeabilities in the microdarcy[26] range, or lower, and are typically associated with organic-rich shales with total organic carbon by weight percent from 0.5% to more than 10%. However, non-shale rocks—such as chalk, marlstones, tight limestone, dolomites, siltstones or sandstones—can also be classified as unconventional reservoirs. Tight non-shale rocks are often located near, or are interbedded with, organic-rich shales, which serve as source rocks for the hydrocarbons.

Dozens of rock formations that occur in parts of at least 20 states have been identified as having commercial unconventional oil or gas reserves. The Marcellus, Utica, Woodford, and Barnett Formations are examples of prolific gas-producing shales. The Bakken, Wolfcamp, Eagle Ford, and Bone Springs Formations are examples of prolific oil-producing shales. Many of these formations, such as the Eagle Ford and Bakken, produce both oil and natural gas in commercial volumes.

Figure 7-6 shows the locations and extent of Lower 48 U.S. unconventional oil and natural gas plays (does not present Alaska).[27] In

24 Kuuskraa, V. A. (January 1, 2009). "Cost-Effective Remediation Strategies for Storing CO2 in Geologic Formations." Society of Petroleum Engineers. doi:10.2118/126618-MS.

Zahasky, C., and Benson, S.M., "Evaluation of hydraulic controls for leakage intervention in carbon storage reservoirs," *International Journal of Greenhouse Gas Control*, vol. 47, 2016, p. 86-100.

Brunner, L., and Neele, F., "MiReCOL – A Handbook and Web Tool of Remediation and Corrective Actions for CO_2 Storage Sites," *Energy Procedia*, vol. 114, 2017, p. 4203-4213.

25 National Energy Technology Laboratory. (2017). "FE/NETL CO2 Storage Cost Model," U.S. Department of Energy, https://edx.netl.doe.gov/dataset/fe-netl-co2-saline-storage-cost-model-2017.

26 A darcy (or darcy unit) is a unit of porous permeability widely used in petroleum engineering and geology. One darcy is equal to the permeability of a medium through which the rate of flow of a fluid having one centipoise viscosity under a pressure gradient of one atmosphere per centimeter would be one cubic centimeter per second per square centimeter cross section.

27 Energy Information Administration, U.S. Department of Energy. (2016). Summary Maps: Shale Gas and Shale Oil Plays, Lower 48 States; June 30, 2016. Washington, DC, 2016.

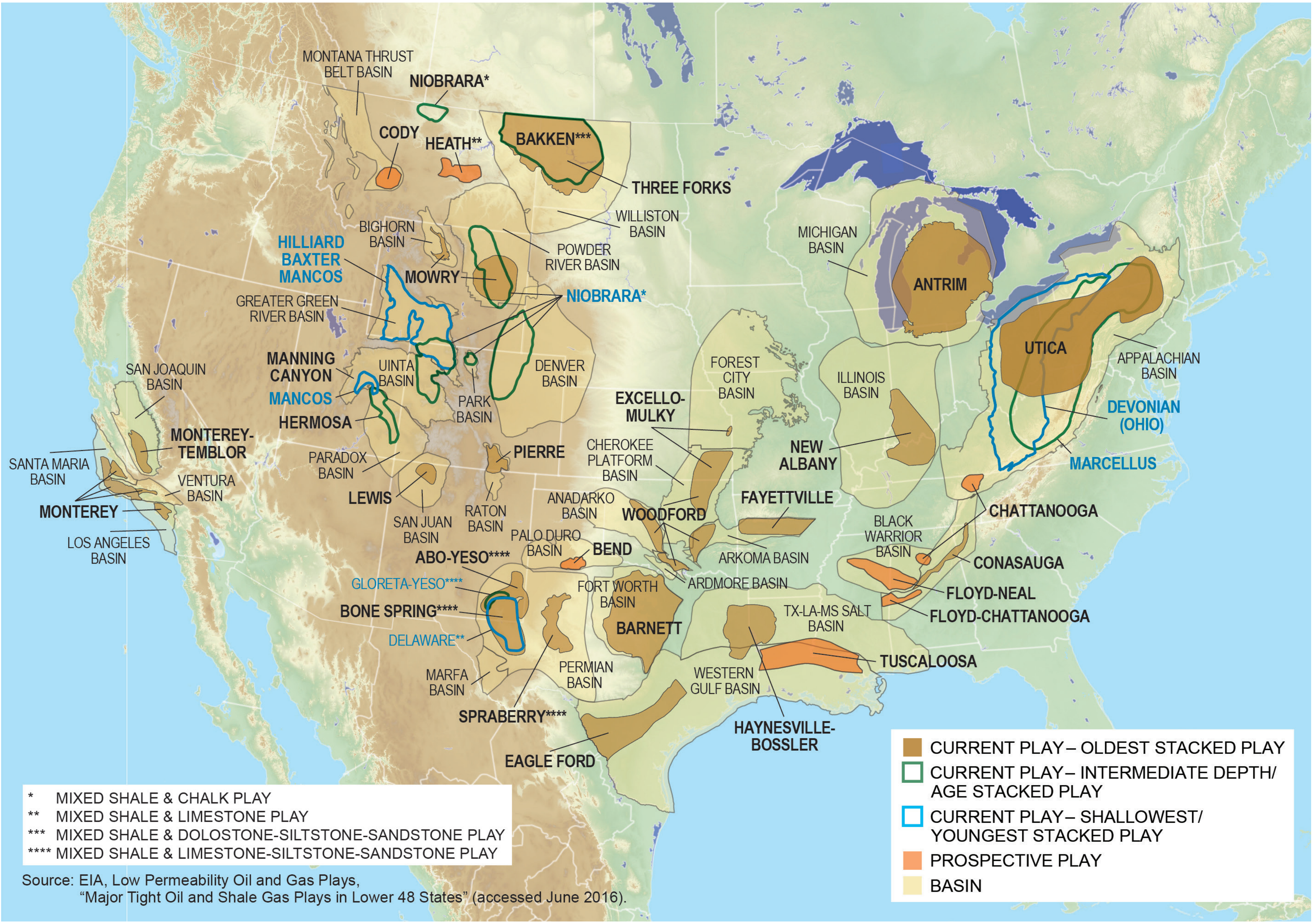


Figure 7-6. *Unconventional Oil and Natural Gas Plays in the Lower 48 States*

2017, most of the oil and natural gas produced in the United States came from unconventional reservoirs. The EIA estimates that in 2017, about 62% of total U.S. natural gas production was produced from shale formations, and a little more than 50% of total U.S. crude oil was produced from shale and unconventional tight non-shale formations.[28] The proliferation of drilling and production in unconventional reservoirs over the past decade has included them as potential targets for CO_2 storage.

There are several published estimates of CO_2 storage resources in unconventional oil and natural gas reservoirs. In 2005, Nuttall et al. estimated ~28 Gt of CO_2 can be technically stored in portions of the Ohio Shale and New Albany Shale.[29] In 2013, Godec et al. estimated a theoretical maximum CO_2 storage potential of 171 Gt for portions of the Marcellus Shale, although the technically accessible CO_2 storage is estimated at 55 Gt.[30] Tao and Clarens developed a production-based model to estimate theoretical CO_2 storage potentials and reported 10.4 Gt to 18.4 Gt of CO_2 could be stored in the Marcellus Shale by 2030.[31] Godec et al. used estimates of gas in place and economic ultimate recovery reported by the EIA in 2011[32] to estimate the technically accessible CO_2 storage potential of 134 Gt in 19 shale formations in the United States.[33] With respect to CO_2 storage in unconventional tight oil formations, the results of past research efforts suggest that the storage resource of the Bakken Formation ranges from a minimum of 160 Mt to as high as 3.2 Gt.[34] Though there is a lack of similar storage resource estimates for other tight oil formations, it is reasonable to assume that the Eagle Ford and Wolfcamp Formations in Texas, which are similar to the Bakken Formation, may have similar magnitudes of CO_2 storage capacities.

Although the literature suggests the CO_2 storage potential of unconventional reservoirs may be significant, those estimates are derived from studies based on laboratory experiments, modeling exercises, and unproven correlations of hydrocarbon resource-in-place estimates or production history compared with potential storage resource. There is a lack of knowledge about the fundamental physical and chemical mechanisms controlling many critical aspects of storage in unconventional reservoirs—injectivity, sweep/storage efficiency, and the roles of sorption, wettability, and thermal maturity—and this has precluded them for consideration as primary targets for CO_2 storage. The widespread exploitation of unconventional shale resources is a relatively recent development, within the last 10 to 15 years. Thus, the current level of knowledge about the mechanisms that affect storage of CO_2 in unconventional reservoirs is relatively low when compared with the knowledge of CO_2 injectivity and behavior in conventional reservoirs, which has more than 40 years of history.

To better evaluate the efficacy of CO_2 storage in unconventional reservoirs with tight oil, future research should focus on acquiring a better understanding of the factors that affect long-term injectivity, migration, and storage of CO_2 in different rock types. Both laboratory and modeling-based studies are needed to address questions of fluid and flow behavior in the context of relative permeability because these data are essential for accurately modeling CO_2 behavior in tight formations, especially those that are rich in organic carbon.

28 Energy Information Administration, U.S. Department of Energy. (2017). *Annual Energy Outlook 2017*, https://www.eia.gov/aeo, January 5, 2017, Washington, DC.

29 Nuttall, B. C., Eble, C. F., Drahovzal, J. A., and Bustin, M. R. (2005). "Analysis of Devonian black shales in Kentucky for potential carbon dioxide sequestration and enhanced natural gas production," Kentucky Geological Survey Final Report to U.S. Department of Energy.

30 Godec, M., Koperna, G., Petrusak, R., and Oudinot, A. (2013b). "Assessment of factors influencing CO_2 storage capacity and injectivity in eastern U.S. gas shales," GHGT-11, *Energy Procedia*, vol. 37, p. 6644-6655.

31 Tao, Z., and Clarens, A., "Estimating the carbon sequestration capacity of shale formations using methane production rates." *Environmental Science & Technology*, 2013, 47 (19), pp. 11318-11325, doi: 10.1021/es401221j.

32 Energy Information Administration, U.S. Department of Energy, "Review of Engineering Resources: U.S. Shale Gas and Shale Oil Plays," Washington, DC, 2011.

33 Godec, M. L., Jonsson, H., and Basava-Reddi, L. (2013a). "Potential global implications of gas production from shales and coal for geological CO_2 storage." *Energy Procedia*, vol. 37, 6656-6666.

34 Sorensen, J. A., Braunberger, J. R., Liu, G., Smith, S. A., Klenner, R. C. L., Steadman, E. N., and Harju, J. A. (2014). "CO_2 storage and utilization in tight hydrocarbon-bearing formations—a case study of the Bakken Formation in the Williston Basin," *Energy Procedia*, vol. 63, p. 7852–7860.

State and federal resources and permitting policies should emphasize ways to facilitate more CO_2-based pilot tests in oil and natural gas producing unconventional reservoirs. Because each formation is unique, it is important that tests are conducted in several different plays to capture the effects that variability in reservoir characteristics may have on CO_2 storage in unconventional reservoirs.

C. Regulations Governing CO_2 Storage in Offshore Formations

The United States offshore consists of submerged lands under the jurisdiction of the coastal states and submerged lands that are under federal jurisdiction, referred to as the Outer Continental Shelf (OCS). The OCS consists of 2.3 billion acres of submerged lands, subsoil, and seabed lying between the seaward extent of the states' submerged lands and the seaward extent of federal jurisdiction. For most areas, federal jurisdiction begins three nautical miles from the shore baseline. However, for Texas and the Gulf Coast of Florida, federal jurisdiction begins nine nautical miles from the baseline, while for Louisiana, federal jurisdiction begins three nautical miles from the baseline. The seaward extent of U.S. federal jurisdiction typically extends to the Exclusive Economic Zone (EEZ), 200 nautical miles from the shore baseline. Beyond the EEZ are international waters.

The storage of CO_2 in the submerged lands within the states' jurisdiction is regulated by the United States EPA UIC program under the U.S. Safe Drinking Water Act of 1974. The Presidential Interagency Task Force on Carbon Capture and Storage examined the existing U.S. regulatory framework for CO_2 storage on the OCS. In 2010, the task force recommended the development of a comprehensive U.S. framework for leasing and regulating sub-seabed CO_2 storage operations on the OCS that addresses the broad range of relevant issues and applies appropriate environmental protections. However, this comprehensive framework has yet to be established. Therefore, the existing regulatory framework is shared across multiple federal agencies, including the Department of the Interior (DOI) and EPA, and may have jurisdictional gaps and redundancies.

1. Advantages of Offshore CO_2 Storage

As discussed in the following sections, there are many geologic formations in the offshore environment that are suitable for geologic storage of CO_2. Very little work has been performed in the breakdown of available storage capacity separating state from federal offshore formations. The extent, thickness, porosity, permeability, and security (suitable cap rock formations) make the injectivity and storage capacity of offshore formations ideal candidates for CO_2 storage. There may be advantages in conducting these operations offshore due to the following factors:

- The offshore environment is managed by state and federal entities instead of the private landowners for onshore environments that can potentially number in the hundreds.
- DOE has conducted, and continues to conduct, extensive research to assess the capacity potential of offshore geologic formations. There are also extensive data from existing oil and natural gas exploration and development—especially in the Gulf of Mexico (GOM) and, to a lesser extent, the Atlantic and Pacific Oceans—as well as other research that contributes to understanding the geologic environment offshore (site characterization, modeling, risk analyses, monitoring protocols).
- Extensive oil and natural gas experience in the GOM provide an extensive knowledge base for CO_2 storage operations in the same environment (e.g., drilling, well installation, decommissioning, analysis of environmental concerns, geologic and geophysical surveying, etc.).
- Some of the existing oil and natural gas infrastructure—platforms, wells, pipelines—could be repurposed for CO_2 storage. Repurposing existing infrastructure for CO_2 storage may be cheaper than decommissioning and removal.
- The offshore environment is distant from populated areas, so there would be no private residences near offshore storage sites.
- There are few or no underground sources of drinking water (USDWs) offshore; salinity in offshore geologic formations is generally more than the EPA limit, so the risk to USDWs is negligible to none.
- The ability to install plume and pressure management (relief wells) solutions. Produced

water from these wells would require disposal in accordance with EPA regulations.

- Pressure from the overlying water column may help to keep the CO_2 in a dense phase, also called a supercritical fluid.
- Geologic and geophysical surveying for monitoring may have fewer impediments due to the lack of structures and landowners.

2. Potential Challenges of Offshore CO_2 Storage

There are several challenges to offshore CO_2 storage, such as:

- The lack of clarity regarding jurisdictions and regulatory regime could potentially delay the start of a new project.
- The existing statutory framework is complex and shared across multiple federal agencies and may have jurisdictional gaps and redundancies.
- Long-term liability remains with the operator.
- The potentially high cost of storing CO_2 offshore if there is no access to offshore infrastructure such as oil and natural gas wells.

3. How to Enable Offshore CO_2 Storage Projects

There are several actions that would help to enable offshore CO_2 storage projects. The development of a comprehensive federal framework for leasing and regulating sub-seabed CO_2 storage operations on the OCS is vital to the success of these projects. The EPA has an existing legal and regulatory framework for projects in state waters, so clear federal direction on such matters is a necessity. In addition, this OCS legal framework should address long-term liability, which, for other programs such as oil and natural gas, currently remains with the operator. Reuse of infrastructure for CO_2 storage may also be addressed in the legal framework. Currently, oil and natural gas structures must be decommissioned soon after production has ceased. Targeting existing structures and enabling an extension for CO_2 storage use may facilitate project success. Finally, appropriate monitoring should be required throughout the life of the project and designed in a manner that facilitates clear regulatory direction during site closure.

4. Offshore CO_2 Injection Projects

According to the Global CCS Institute, in 2017 there were 10 offshore CO_2 injection projects operating, under construction, or undergoing advanced study.[35] Several injection facilities are operational in the Barents Sea and North Sea off the coasts of Norway and the Netherlands. Other operational CO_2 injection projects are offshore Brazil and Japan. Many countries are in the process of advanced study of selected offshore storage sites for development or are conducting detailed evaluation of their offshore storage resources.

The next two sections present some of the offshore storage sites listed in the Global CCS Institute online database that were operating or under construction at that time.

a. Operating Offshore Projects

Sleipner. In 1996, the Sleipner storage project in the Norwegian North Sea was the first large-scale offshore CO_2 storage facility in the world. CO_2 is separated from produced natural gas and reinjected into an offshore sandstone reservoir, the Sleipner gas field. Approximately 0.85 Mtpa of CO_2 has been injected and more than 17 Mt have been injected since the start of the project.

Snøhvit. The Snøhvit CO_2 storage site is associated with gas fields in the Barents Sea offshore Norway. CO_2 is captured and processed at a natural gas facility on an island in the north. The captured CO_2 is transported via pipeline to the Snøhvit Field offshore where it is injected into a storage reservoir. More than 4 Mt of CO_2 were stored between 2008 and 2018.

K12-B Field. CO_2 is captured at an offshore natural gas production facility and injected into a depleted gas reservoir, the K12-B gas field off the coast of the Netherlands. Injection of CO_2 began in 2004 and cumulative injection to date is estimated at more than 100,000 tonnes.

Santos Basin. The Petrobras Santos Basin Pre-Salt Oil Field CCUS Project located off the coast of Brazil has four CO_2 separation and injection systems aboard floating vessels anchored in the

35 Global CCS Institute, CO_2RE Database. (2019). https://www.globalccsinstitute.com/resources/co2re/.

Santos Basin. The project started operations in 2013. CO_2 is separated on site as a part of natural gas processing and injected into the Lula and Sapinhoá oil fields for CO_2 EOR. In December 2016, the Santos Basin Pre-Salt development reached the milestone of 4 Mt of CO_2 injected into pre-salt fields.

Tomakomai. The Tomakomai CCUS Demonstration Project captures CO_2 from a hydrogen production unit at a refinery near Hokkaido, Japan. Approximately 100,000 tonnes of CO_2 per year over a 3-year period are being injected into two near-shore storage sites located 3 to 4 kilometers offshore. Post-injection monitoring will continue for 2 years after CO_2 injection stops.

b. Offshore CO_2 Storage Project Under Construction

Haifeng Project. Two carbon capture test facilities will be installed at the Haifeng Power Plant Guangdong in China with offshore storage sites within the Pearl River Mouth Basin of the South China Sea. Total capture capacity for both facilities of the Haifeng Carbon Capture Demonstration Project is estimated at about 70 tonnes per day.

c. Offshore CO_2 Storage Options in the Gulf of Mexico

The states bordering the Gulf of Mexico (Texas, Louisiana, Mississippi, Alabama, Florida) have a high concentration of heavy industry and associated electrical power generation that creates an area of elevated CO_2 emissions. Significant reductions in national emissions could be achieved by focusing on extending onshore storage opportunities to access the large-volume offshore storage reservoirs in this region. The Gulf Coast region offers excellent source-sink matching, proven capture facilities (Air Products, Petra Nova), and developing transportation infrastructure (Denbury's Green CO_2 pipeline) for CO_2 EOR.

The Gulf of Mexico Basin is one of the largest-volume geologic sinks in the United States. It can accommodate CO_2 from local and regional sources and potentially serve as a storage resource for regions that lack local, suitable geology. As one of the most explored subsurface geologic basins in the world, the geologic and fluid systems of GOM hydrocarbons are well understood.

Geologic Storage Unit	CO_2 Capacity, billion tonnes
Upper Pliocene	105
Lower Pliocene	144
Upper Miocene	199
Lower Miocene	89
Oligocene	21

Source: Carr, D. L., et al. (2011). "Executive summary: Task 15 – NATCARB Atlas Update – CO_2 Sequestration Capacity, Offshore Western Gulf of Mexico," University of Texas at Austin.

Table 7-3. *Western Offshore Gulf of Mexico CO_2 Storage Capacity Estimates (P50 estimate)*

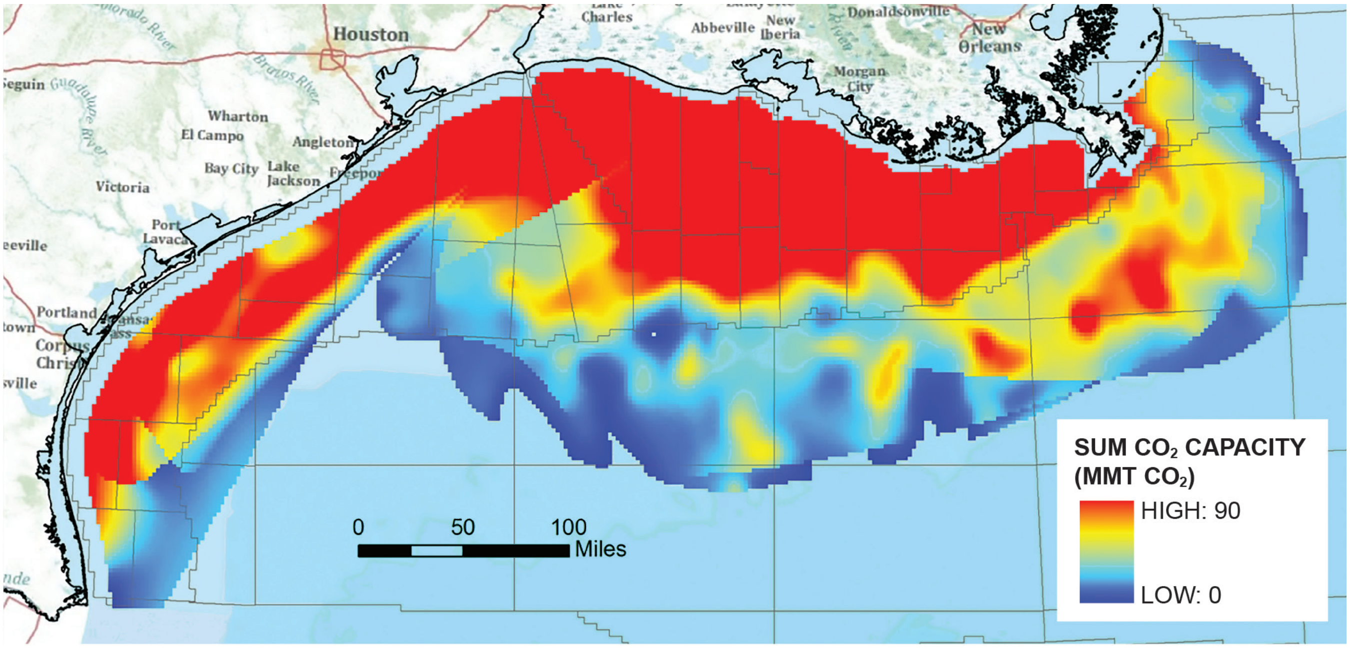
The basin contains multiple geologic storage options, including previously unused porous and permeable sandstone formations that currently contain saline water (saline formations) and depleted oil and natural gas reservoirs from which hydrocarbons have been produced to near economic limits (depleted reservoirs).

Across the GOM region, many studies have been undertaken to characterize the subsurface in various formations. Results from numerous projects in the western GOM can be extrapolated to provide more information on the areas and formations within the greater GOM. Work completed in 2012 estimates that the total CO_2 capacity within the western GOM project area is 559 Gt. Table 7-3 provides estimates of the storage capacity distributed across the five major geologic storage units of the western GOM.[36]

The greatest CO_2 storage capacity in the western GOM lies in Miocene and Pliocene deep saline sandstones. These reservoirs are particularly abundant offshore Louisiana. Substantial capacity, particularly in the Miocene, also occurs along the Texas coast (Figure 7-7).

A 2010 project in the eastern Gulf of Mexico analyzed a 10,000-square mile area offshore Alabama and the western Florida Panhandle and suggested that about 170 Gt of CO_2 could be stored

36 Carr, D. L., Trevino, R., Meckel, T., Brenton, C., Yang, C., and Miller, E. (2011). "Executive summary: Task 15 – NATCARB Atlas Update – CO_2 Sequestration Capacity, Offshore Western Gulf of Mexico," University of Texas at Austin, Bureau of Economic Geology, 2 p. GCCC Digital Publication Series #11-24.



Source: Carr, D. L., Trevino, R., Meckel, T., Brenton, C., Yang, C., and Miller, E. (2011). "Executive summary: Task 15 – NATCARB Atlas Update – CO_2 Sequestration Capacity, Offshore Western Gulf of Mexico," University of Texas at Austin, Gulf Coast Carbon Center.

Figure 7-7. *Potential CO_2 Storage in the Western Gulf of Mexico*

in Miocene sandstone, and at least 30 Gt could be stored in deeper Cretaceous formations.[37]

In 2018, the DOE awarded two projects for further study of storage and CO_2 EOR opportunities in the GOM. One project was awarded to the Southern States Energy Board (SSEB) and the other to the University of Texas, Bureau of Economic Geology (BEG). The SSEB project focuses on the eastern GOM while the BEG project focuses on the western GOM. The programs support the DOE's long-term objective to ensure a comprehensive assessment of the potential to implement offshore CO_2 subsea storage in the DOI's Bureau of Ocean Energy Management (BOEM), Outer Continental Shelf Oil, and Gas Leasing Program Planning Areas in the GOM. The goal of this effort is to expand the knowledge base required for commercially viable, secure, long-term, large-scale CO_2 subsea storage, with or without enhanced hydrocarbon recovery. The effort is also intended to support the DOE's long-term objective to ensure a comprehensive assessment of the potential to implement offshore CO_2 subsea storage in the GOM.

d. Offshore CO_2 Storage Options in the Atlantic Ocean

Offshore Atlantic CO_2 storage resources have been described by numerous authors, and in 2018 was the focus of two investigations by the Midwest Regional Carbon Sequestration Partnership and the Southeast Regional Carbon Sequestration Partnership, both of which are funded by DOE. Previous investigations[38] have identified

37 Hills, D. J., and Pashin, J. C. (2010). "Final Report: Southeastern Regional Carbon Sequestration Partnership (SECARB) Phase III – Task 15: Preliminary evaluation of offshore transport and storage of CO_2," Southern States Energy Board, 16 p., https://doi.org/10.13140/RG.2.2.33279.66721.

38 Hovorka, S. D. et al. (2000). "Technical summary: optimal geological environments for carbon dioxide disposal in brine-bearing formations (aquifers) in the United States," University of Texas at Austin, Bureau of Economic Geology, final report prepared for U.S. Department of Energy, National Energy Technology Laboratory, under contract no. DE-AC26-98FT40417, 232 p. GCCC Digital Publication Series #00-01, 203 p., http://www.beg.utexas.edu/gccc/bookshelf/Final%20Papers/00-01-Final.pdf.

Midwest Regional Carbon Sequestration Partnership. (2011). "Preliminary characterization of CO_2 sequestration potential in New Jersey and the offshore coastal region," Midwest Regional Carbon Sequestration Partnership, final report prepared for U.S. Department of Energy, National Energy Technology Laboratory, under Cooperative Agreement DE-FC26-05NT42589, 98 p., https://irp-cdn.multiscreensite.com/5b322158/files/uploaded/njgs_carbon_sequestration_report_web.pdf.

U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). National Assessment of Geologic Carbon Dioxide Storage Resources—Results (ver. 1.1, September 2013): U.S. Geological Survey Circular 1386, 41 p., http://pubs.usgs.gov/circ/1386/.

CO_2 storage potential in Upper Jurassic and Cretaceous, which are aged saline reservoirs located below the seafloor in state-regulated Atlantic waters and the federal areas of the OCS. In addition to the Jurassic and Cretaceous saline reservoir storage potential in the offshore Atlantic, there is also potential for CO_2 mineralization storage in basaltic rock formations associated with Mesozoic-age rift basins found in offshore areas near New York, New Jersey, Georgia, and Florida.[39]

Offshore Atlantic CO_2 storage resources are largely uninvestigated because geologic information is limited. Fifty-one oil and natural gas exploration wells were drilled in the Atlantic OCS between 1976 and 1983.[40] All wells were abandoned as noncommercial at the time. In 2019, there are no active oil and natural gas leases in the Atlantic area.[41] The Delaware Geological Survey Outer Continental Shelf Core and Sample Repository[42] contains samples from all 51 oil and natural gas wells drilled in the Atlantic OCS offshore regions. Samples include cores, unwashed cuttings, vials containing samples processed for micropaleontology and palynology, and thin sections of core, cuttings, and micropaleontology and palynology splits. In addition, 10 wells were drilled in Florida State waters—Atlantic and Florida Bay—and the Straits of Florida OCS.[43] There is a large quantity of legacy seismic data that can be used to characterize the subsea geology.[44] However, approximately 80% of the mid- and south-Atlantic OCS areas have never been surveyed. Publicly available Atlantic offshore seismic data can be accessed at the National Archive of Marine Seismic Surveys.[45]

The northeast and Mid-Atlantic offshore areas under current evaluation for CO_2 storage resources by the Midwest Regional Carbon Sequestration Partnership include the Georges Bank Basin (New England), Long Island Platform, and Baltimore Canyon Trough (New Jersey, Delaware, Maryland).[46] Storage resources calculations were underway in 2018. The southeast Atlantic areas under investigation by the Southeast Regional Carbon Sequestration Partnership include the Carolina Trough (the Carolinas), Southeast Georgia Embayment (Georgia, Florida), and the Blake Plateau Basin (Georgia, Florida). Southeast Atlantic offshore regional CO_2 storage capacity in Upper Cretaceous strata is estimated to be approximately 32 Gt.[47]

One offshore Atlantic geologic storage project has been proposed off the coast of New Jersey by SCS Energy. The PurGen One project planned to capture CO_2 at a proposed power plant in Linden, New Jersey, and transport 70 miles offshore to an injection site through a 140-mile pipeline.[48] The CO_2 would have been injected into a Cretaceous age saline sandstone formation in the Baltimore Canyon Trough approximately 8,000 feet below the sea floor in a water depth of about 300 feet. The project was canceled in 2011 due to a lack of public support for a new coal-fired power plant.[49]

39 Goldberg, D. S., Kenta, D. V., and Olsen, P. E. (2010). "Potential onshore and off-shore reservoirs for CO_2 sequestration in Central Atlantic magmatic province basalts," *Proceedings of the National Academy of Sciences*, vol. 107, no. 4, p. 1327–1332, www.pnas.org/cgi/doi/10.1073/pnas.0913721107.

40 Bureau of Ocean Energy Management. (2018). Atlantic Oil and Gas Information, Bureau of Ocean Energy Management website, https://www.boem.gov/Atlantic-Oil-and-Gas-Information/.

41 Bureau of Ocean Energy Management. (2018).

42 Delaware Geological Survey. (2018). Outer Continental Shelf Core and Sample Repository, Delaware Geological Survey website, https://www.dgs.udel.edu/projects/outer-continental-shelf-core-and-sample-repository.

43 Lloyd, J. M., "1994, 1992 and 1993 Florida petroleum production and exploration," Florida Geological Survey, Information Circular No. 110, http://ufdc.ufl.edu//UF00082065/00003.

44 International Association of Geophysical Contractors. (2018). "U.S. Atlantic seismic surveys," International Association of Geophysical Contractors, https://www.iagc.org/uploads/4/5/0/7/45074397/iagc_us_atlantic_seismic_surveys_final_20180420.pdf.

45 Triezenberg, P. J., Hart, P. E., and Childs, J. R. (2016). "National Archive of Marine Seismic Surveys: A USGS data website of marine seismic reflection data within the U.S. Exclusive Economic Zone," U.S. Geological Survey Data Release, https://doi.org/10.5066/F7930R7P.

46 Cumming, L., Gupta, N., Miller, K., Lombardi, C., Goldberg, D., ten Brink, U., Schrage, D., Andreasen, D., and Carter, K. (2017). "Mid-Atlantic U.S. Offshore Carbon Storage Resource Assessment," *Energy Procedia*, vol. 114, p. 4629–4636.

47 Almutairi, K. F., Knapp, C. C., Knapp, J. H., and Terry, D. A. (2017). "Assessment of Upper Cretaceous strata for offshore CO_2 storage, southeastern United States," *Modern Environmental Science and Engineering*, vol. 3, no. 8, p. 532–552, http://www.academicstar.us/UploadFile/Picture/2018-1/20181301259753.pdf.

48 Vidas, H., Hugman, B., Chikkatur, A., and Venkatesh, B. (2012). "Analysis of the costs and benefits of CO_2 sequestration on the U.S. Outer Continental Shelf," Bureau of Ocean Energy Management, OCS Study BOEM 2012-100. Prepared under BOEM Contract M10PC00117 by ICF International, 129 p. https://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Energy_Economics/External_Studies/OCS%20Sequestration%20Report.pdf.

49 Vidas, H. et al. (2012).

e. CO_2 Storage Options in the Pacific Ocean

Beneath Pacific waters of the United States offshore California, Oregon, Washington, Alaska, and Hawaii, current prospects for geologic CO_2 storage exist in known oil-producing basins in Southern California and Alaska. Additional opportunities, which were undergoing initial study, may lie in the basalt formations offshore of Washington, Oregon, and potentially Hawaii. These potential offshore storage areas have radically different geologic settings.

Potential targets for CO_2 geologic storage with or without associated CO_2 EOR include the producing oilfields and nonproducing structures (geologic traps) in offshore portions of the Los Angeles, Ventura, and Santa Maria Basins in southern California and the Cook Inlet Basin in Alaska. The onshore parts of the southern California basins were identified as strong prospects for CO_2 EOR in a 2005 study commissioned by DOE,[50] and the offshore part of each basin is geologically like the onshore part. Further, the offshore part of the Ventura Basin is continuous (geologically on-trend) with the onshore part. Although no offshore CO_2 injection projects exist to date, the economic pursuit of CO_2 EOR projects in these basins should yield local knowledge that will support eventual CO_2 injection projects not involving EOR (pure-storage projects). Possible CO_2 geologic storage offshore California would also be able to take advantage of many large CO_2 sources onshore that are nearby, and by the presence of existing drilling- and pipeline-related infrastructure.

Similarly, Alaska has producing offshore oilfields in the Cook Inlet Basin near Anchorage, demonstrating the presence of geologic structures appropriate for CO_2 storage. These structures may be injection targets for CO_2 currently emitted by onshore oil refineries and fossil-fuel power plants located nearby. While potential CCUS targets probably also exist in the Beaufort and Chukchi Seas (notably near Prudhoe Bay), the lack of a CO_2 source and the harsh operating environments render these locations infeasible in the near term.

There are no CO_2 geologic storage projects operating in the United States sector of the Pacific. The Pacific exclusive economic zone contains mainly clastic (versus carbonate) reservoir rock of Mesozoic and Cenozoic age. Compared with the Gulf of Mexico and midcontinent, the more active tectonic settings would limit storage prospectively in some areas. However, research on a new storage concept holds promise for secure CO_2 storage beneath the seafloor of large areas offshore Washington, Oregon, and Hawaii. The Cascadia CarbonSAFE Project seeks to inject CO_2 into basaltic rock, where it would eventually mineralize and become permanently stable. Vast areas of basaltic rock occur in ocean basins worldwide as well as in certain onshore areas, such as in Washington State, Russia, and India.

The Cascadia Project site has been extensively drilled and studied for geologic research purposes and has an instrumented observation network through which data are cabled onshore. The project conducted a prefeasibility study to evaluate the technical and nontechnical aspects of collecting and storing 50 Mt of CO_2 at the site. Its Phase I accomplishments include: (1) a compiled evaluation of industrial CO_2 sources and potential modes of transportation in the region, (2) an inventory of existing geophysical and geologic data in the area and evaluation of new data required to further assess storage potential and pre-/post-injection environmental monitoring needs, (3) an initial reservoir model of the potential storage complex, (4) a preliminary analysis of regulatory requirements, stakeholder, and financial needs for the offshore storage complex, and (5) a comprehensive project risk assessment analysis.

Preliminary simulations indicate that injectivity into the basalt rock is high, and that a 50 Mt CO_2 plume injected over a 20-year period will remain within the reservoir area for at least a 50-year period. Lab-based studies show that the injected CO_2 would be fully converted to carbonate minerals in 135 years or less.

50 Advanced Resources International. (2005). Basin-Oriented Strategies for CO2-Enhanced Oil Recovery: California. Prepared for U.S. Department of Energy, April 2005.

D. CO_2 Storage in Depleted Hydrocarbon Reservoirs

Conventional oil and natural gas reservoirs are porous rock formations, typically sandstones and carbonates, with structural geometries that contain trapped hydrocarbons. Using primary pressure-driven production methods, the production of oil from conventional reservoirs commonly yields 20% to 30% of the original hydrocarbon in place and 60% to 70% of the gas, and an additional 10% to 15% during secondary water flooding. Pore space vacancies generated during reservoir depletion create an ideal storage repository for CO_2 after the field has reached its economic production limit due, in large part, to the formation's well-established structural integrity that trapped buoyant fluids for millennia.

A potential advantage of these sites is that preexisting infrastructure may exist for storage due to prior field industrialization[51] and may have utility for CO_2 storage operations. There is also the potential for favorable source-sink matching with proximal stationary CO_2-emitting sources. Furthermore, oilfields with remaining oil after completion of primary and secondary recovery operations may be candidates for EOR methods, including CO_2 EOR. CO_2 storage can also take place adjacent to, above, or below depleted or active hydrocarbon reservoirs, realizing additional storage capacity while utilizing existing oilfield infrastructure.[52] Incidental CO_2 trapping associated with CO_2 EOR is described in Chapter 8, "CO_2 Enhanced Oil Recovery." CO_2 storage after the conclusion of CO_2 EOR operations may also present a good storage opportunity.

1. Advantages of CO_2 Storage in Depleted Hydrocarbon Reservoirs

The advantages to storing CO_2 in depleted hydrocarbon reservoirs include: (1) well-known and characterized reservoir properties, (2) established trapping and sealing mechanisms of buoyant fluids in structural and stratigraphic traps, (3) potential trapping of CO_2 in un-swept (remaining) oil and water rather than remaining as a separate phase, (4) reservoirs with weak water drive[53] may deplete pressure to further enhance storage capacity,[54] and (5) use of existing oilfield infrastructure, such as wells. These advantages enable more reliable and robust predictions of the long-term fate of the CO_2 in proven reservoirs, enhance storage capacity in amenable reservoirs, and reduce the overall costs of storage. Furthermore, CO_2 storage operations may face less opposition from stakeholders in regions with a history of hydrocarbon production.

An estimated 190 to 230 Gt of CO_2 storage capacity has been established in U.S. oil and natural gas reservoirs.[55] These fields are found in basins that cover an extensive portion of the onshore United States, from the Appalachian Basin in the east, the Permian and Gulf Basins in the south, and the Sacramento Basin in the west. Figure 7-8 shows the distribution of natural gas fields within those basins. Additional opportunities for storage may potentially exist after CO_2 EOR operations have ceased by offering a residual CO_2 saturation. This may act to enhance CO_2 injectivity and, in conjunction with further pressure depletion, enable improved storage capacity.

2. Challenges of CO_2 Storage in Depleted Hydrocarbon Reservoirs

There are several technical challenges to using depleted oil fields for CO_2 storage. First, during the process of primary and secondary oil production, oil fields undergo large changes in stress that have irreversible effects on the rock properties. Not only does this permanently reduce the pore volume of the rock, but it can also make the rocks more susceptible to hydraulic fracturing.[56]

51 DOE/NETL Carbon Storage Atlas (2015).

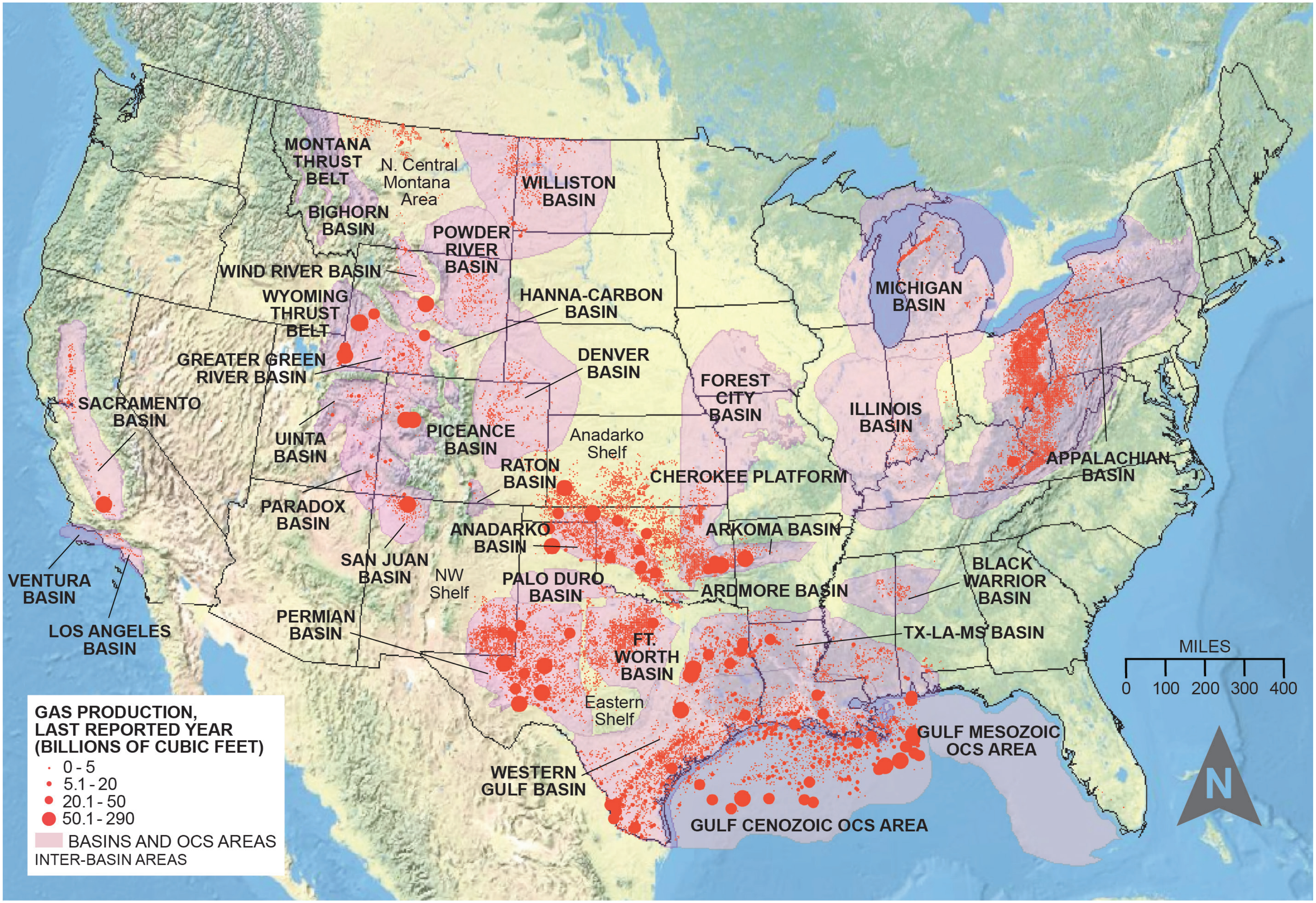
52 Esposito, R. A., Pashin, J. C., and Walsh, P. M., "Citronelle Dome: A Giant Opportunity for Multi-Zone Carbon Storage and Enhanced Oil Recovery in the Mississippi Interior Salt Basin of Alabama," *Environmental Geosciences*, 2008, 15(2), 1-10.

53 A weak water drive describes a reservoir where support from the surrounding aquifer is limited, generally resulting in significant pressure depletion during hydrocarbon production.

54 Hovorka, S. D. (2010). *EOR as Sequestration-Geoscience Perspective*, Bureau of Economic Geology, Jackson School of Geosciences, University of Texas at Austin.

55 DOE/NETL Carbon Storage Atlas (2015).

56 Chan, A. W., and Zoback, M. D. (2002). "Deformation Analysis in Reservoir Space (DARS): A Simple Formalism for Prediction of Reservoir Deformation with Depletion," in *Proceedings of the SPE/ISRM Rock Mechanics in Petroleum Engineering Conference*.



Source: EIA Maps, based on data from USGS, updated April 2009.

Figure 7-8. *Distribution of Natural Gas Production in the Lower 48 States*

Second, hydrocarbons are produced from oil and natural gas reservoirs through wells that penetrate numerous stratigraphic intervals in the subsurface. These penetrations provide potential conduits for the leakage of CO_2 out of the reservoir, necessitating stringent well monitoring protocols. Any reactivation of hydrocarbon extraction activities in the field may result in additional leakage risks through newly drilled wells. And hydrocarbon well completion and stimulation practices may impact cap rock integrity. Although it is unlikely, there is also the potential that the cap rock may endure compaction damage when the reservoir's pore fluid pressure is decreased during production.[57]

Third, when injecting CO_2 into depleted reservoirs, proper modeling of multiphase flows in wells is needed to ensure that Joule-Thomson effects[58] in the wellbore do not lead to extreme cold temperatures that form ice and could damage the well or cement.

Legal issues also pose a challenge to storage in depleted oil and natural gas fields because hydrocarbon production leases do not address CO_2 injection or storage without the primary objective of hydrocarbon production. Injecting CO_2 into a depleted oil reservoir negates or complicates any future recovery of remaining oil resources if new technology or economic conditions might warrant such a scenario. Once hydrocarbon production ceases for a specified period, a lease agreement between the operator and oil or gas owner is typically terminated. CO_2 storage, therefore, necessitates developing a new contractual arrangement, and a primary challenge with CCUS is the ownership of subsurface pore space. Law reviews suggest it is likely that landowners will retain ownership of the pore space.[59] Therefore, any new framework may require a suite of new criteria to resolve the challenges facing CO_2 storage in depleted hydrocarbon reservoirs.

Storing additional CO_2 in an oil field after the completion of CO_2 EOR operations also poses some unique challenges. CO_2, and often water, are injected into the oil field during CO_2 EOR, and oil, natural gas, water, and CO_2 are produced. If the injection is optimized for CO_2 storage, any CO_2 produced will be recycled for reinjection into the reservoir. The average CO_2 saturations in the flooded portion of the oil field can be 20% or more. This contrasts with the average saturation of CO_2 of 5% to 8% in many CO_2 storage formations at the end of CO_2 injection. At the end of CO_2 EOR operations, if CO_2 continues to be injected into the same wells without removing brine or oil, the CO_2 may be pushed outside the boundaries of the oil field. This will require precise reservoir engineering to avoid this scenario by accessing any remaining storage space.

E. Other Storage Options

This section briefly describes other available geologic CO_2 storage options that have been investigated and tested at various scales. Two options are discussed here:

1. CO_2 injection and storage in deep subsurface coal beds; for example, during enhanced coalbed methane recovery
2. CO_2 mineralization to form solid carbonate phases in basaltic and ultramafic rocks and mine tailings.

Compared to the CO_2 storage resources that are available in deep saline formations and depleted oil and natural gas reservoirs in sedimentary basins, storage options in subsurface coal beds may be of local interest in areas where coal-bearing rocks occur. Conversely, vast CO_2 mineralization storage volumes may be available in onshore and offshore basalts. It should be noted that while some limited R&D is being performed in these alternative storage options, no demonstration- or commercial-scale projects have been conducted to determine the long-term feasibility of these storage options. Both technical and regulatory issues remain as barriers for commercial-scale development.

57 IEA Greenhouse Gas R&D Programme (IEA GHG), "CO_2 storage in Depleted Gas Fields," 2009/01, June 2009.

58 Joule–Thomson effect describes the temperature change of a real gas or liquid when it is forced through a valve (or wellbore or perforation) while keeping it insulated so that no heat is exchanged with the environment.

59 Duncan, I. J., Anderson, S., and Nicot, J. P. (2009). "Pore space ownership issues for CO_2 sequestration in the US." *Energy Procedia*, vol. 1, p. 4427-4431. GHGT-9, https://www.sciencedirect.com/science/article/pii/S1876610209009011?via%3Dihub#aep-bibliography-id13.

Burt, S. L. (2016). "Who Owns the Right to Store Gas: A Survey of Pore Space Ownership in U.S. Jurisdictions," http://www.duqlawblogs.org/joule/wp-content/uploads/2016/04/Burt-Article-with-Burt-Edits-4.28.pdf.

1. CO_2 Storage in Deep Subsurface Coal Beds

Coal is a rock composed primarily of preserved organic material. CO_2 injected into a coal bed rapidly absorbs into the organic material in coal and is trapped by a process called adsorption trapping. Deep coal beds, beds that may not be mined for economic or technical limitations, can be used to store CO_2. The target coal beds must have enough permeability to allow the injected CO_2 to reach far into the coal to be absorbed onto the organic material. However, laboratory research and field tests have shown that CO_2 injection into coal can decrease permeability and adversely impact CO_2 injectivity rates. The injected CO_2 does not need to be in the supercritical (dense phase) state for it to be adsorbed by coal, allowing CO_2 storage in coals to take place at shallower depths (at least 650 feet or 200 meters deep) than storage in oil and natural gas reservoirs or deep saline formations (at least 3,000 feet or 1 km deep). An added benefit to storing CO_2 in coal beds is that the injected CO_2 may displace methane that naturally occurs in most coal beds (CO_2-enhanced coalbed methane recovery). CO_2-enhanced coalbed methane recovery is analogous to CO_2 EOR in that the revenue from the sale of the produced hydrocarbons can help to offset the cost of CO_2 storage.

DOE's National Energy Technology Laboratory (2015)[60] estimated that the United States may have a median CO_2 storage capacity of 80 billion Mt in deep coal beds. There have been multiple CO_2-enhanced Coalbed Methane Recovery pilots and demonstration tests conducted worldwide.[61] However, according to the Global CCS Institute online database, there are no planned or active coal-bed CO_2 storage projects. This is due in part to the technical challenges encountered during pilot projects performed in the southeastern United States.

2. CO_2 Mineralization in Basaltic and Ultramafic Rocks

Geologic storage of CO_2 is possible by injecting it into subsurface basaltic and ultramafic rocks or by reacting CO_2-bearing fluid or gas with mine tailings rich in mafic minerals.[62,63] According to a 2018 report by NASEM, CO_2 mineralization may occur in one of three ways:

- Ex situ carbon mineralization—Solid mineral reactants are transported to a site of CO_2 capture then react with fluid or gas rich in CO_2
- Surficial carbon mineralization—CO_2-bearing fluid or gas reacts with mine tailings, alkaline industrial wastes, or sedimentary formations rich in reactive rock fragments, all with a high proportion of reactive surface area
- In situ carbon mineralization—CO_2-bearing fluids are circulated through suitable reactive rock formations at depth.

With ex-situ or surficial mineralization, CO_2 is stored through reaction with crushed material at the surface to form a stable carbonate. Examples include captured CO_2 reacting with mafic and ultramafic mine tailings or industrial byproducts such as fly ash, cement kiln dust, and iron and steel slag.[64]

During in situ pilot studies of CO_2 injection into subsurface mafic rocks in Iceland and southeastern Washington, rapid subsurface carbonate

60 DOE/NETL Carbon Storage Atlas (2015).

61 Sloss, L. L. (2015). "Potential for enhanced coalbed methane recovery," International Energy Association Clean Coal Centre, 41 p., https://www.usea.org/sites/default/files/media/Potential%20for%20Enhanced%20coalbed%20methane%20recovery%20-ccc252.pdf.

62 Kelemen, P. B., Matter, J., Streit, E. E., Rudge, J. F., Curry, W. B., and Blusztajn, J. (2011). "Rates and mechanisms of mineral carbonation in peridotite: Natural Processes and Recipes for Enhanced, in situ CO_2 Capture and Storage," *Annual Review of Earth and Planetary Sciences*, v. 39, no. 1, p. 545–576, https://doi.org/10.1146/annurev-earth-092010-152509.

63 Mafic minerals are those that are rich in magnesium and iron. Suitable rocks for large-scale CO_2 mineralization include the ultramafic rocks dunite, peridotite, and serpentinite and the mafic rock basalt. See Blondes, M. S., Merrill, M. D., Anderson, S. T., and DeVera, C. A. (2019). "Carbon dioxide mineralization feasibility in the United States," U.S. Geological Survey Scientific Investigations Report 2018–5079, https://doi.org/10.3133/sir20185079.

64 Kirchofer, A., Becker, A., Brandt, A., and Wilcox, J. (2013). "CO_2 Mitigation potential of mineral carbonation with industrial alkalinity sources in the United States," *Environmental Science & Technology*, v. 47, no. 13, p. 7548–7554, https://doi.org/10.1021/es4003982.

Power, I. M., McCutcheon, J., Harrison, A. L., Wilson, S. A., Dipple, G. M., Kelly, S., Southam, C., and Southam, G. (2014). "Strategizing Carbon-Neutral Mines: A Case for Pilot Projects," *Minerals*, v. 4, no. 2, p. 399–436, https://doi.org/10.3390/min4020399.

mineralization has been shown to occur within 2 years after injection of CO_2.[65] In 2009, researchers began conducting a prefeasibility study for storing 50 Mt of CO_2 in oceanic basalts in the Cascadia Basin, offshore Washington, and British Columbia.[66]

A detailed assessment of CO_2 storage resources associated with mineralization has not been completed for the United States. However, there are significant mafic basalts and ultramafic rock volumes that could be used for the mineralization process. Suitable ex-situ and surficial carbon mineralization targets include asbestos or other ultramafic mine tailings, and in situ targets include ultramafic rocks on the East and West Coasts, the Columbia River Basalts in the Pacific Northwest, and the Midcontinent Rift Zone basalts in the midcontinent. Hawaii has volumes of potential in situ target reservoir rocks that could be used to mitigate local CO_2 emissions.[67] The 2018 NASEM report described the CO_2 mineralization potential in basaltic and ultramafic rocks as essentially unlimited and recommended increased funding for research to better quantify the CO_2 mineralization resources of the United States.

IV. ENABLING AT-SCALE DEPLOYMENT OF CO_2 STORAGE

A. Build on Other Efforts

The DOE's National Risk Assessment Partnership (NRAP) initiative is focused on developing the science base and associated toolsets to elucidate the behavior of CO_2 storage sites despite geologic uncertainty. Many decisions for a commercial CO_2 storage operation must be made before the detailed behavior of the site can be probed empirically during injection operations. These decisions relate to estimation of storage capacity, strategies to optimize storage, design of an effective and economic monitoring plan, and plan for site closure.

Utilizing resources and expertise across the DOE national lab complex, the NRAP initiative has been using a unique hybrid of physics-based simulations and empirical models to reveal how CO_2 storage systems are likely to perform over a range of variable conditions. The initiative is grounding these predictive tools in targeted experiments and field-based observations to quantify key processes associated with storage-system performance.

Several important findings relevant to commercial deployment of CO_2 storage have emerged from the NRAP initiative:

- If an adequate geologic model is available, the primary factors that affect how a storage site will respond to fluid injection and extraction can be predicted by using existing methods for predicting fluid flow, geochemical reactions, and geomechanical responses. Prediction accuracy is further improved after initial CO_2 plume monitoring data are available and used to calibrate the model. This is not meant to imply that the rate and direction of CO_2 plume movement in a reservoir can be predicted precisely using conventional approaches, or that all subsurface processes are completely understood or are fully embodied in conventional simulation methods. Rather, it acknowledges, for example, that a Darcy's law-based prediction of plume evolution has enough physics to inform a decision on CO_2 plume evolution, particularly in a statistical sense. Hence, NRAP has relied heavily on a battery of existing predictive simulators, extending them in new ways to address specific risk-related challenges.

- The major uncertainties in predictions of CO_2 plume evolution—which stem from variability in subsurface characteristics and the associated model parameters—can be bound at levels low enough to make better decisions than

65 Matter, J. M., et al. (2016). "Rapid carbon mineralization for permanent disposal of anthropogenic carbon dioxide emissions," Science, v. 352, no. 6291, p. 1312–1314, https://doi.org/10.1126/science.aad8132.

McGrail, B. P., Schaef, H. T., Spane, F. A., Cliff, J. B., Qafoku, O., Horner, J. A., Thompson, C. J., Owen, A. T., and Sullivan, C. E. (2017). "Field validation of supercritical CO_2 reactivity with basalts," *Environmental Science & Technology Letters*, v. 4, no. 1, p. 6–10, https://doi.org/10.1021/acs.estlett.6b00387.

66 Goldberg, D., and Slagle, A. L. (2009). "A global assessment of deep-sea basalt sites for carbon sequestration," *Energy Procedia*, vol. 1, no. 1, p. 3675–3682, https://doi.org/10.1016/j.egypro.2009.02.165.

67 Blondes, M. S., Merrill, M. D., Anderson, S. T., and DeVera, C. A. (2019). "Carbon dioxide mineralization feasibility in the United States," U.S. Geological Survey Scientific Investigations Report 2018–5079, https://doi.org/10.3133/sir20185079.

in the absence of this probabilistic information. A major challenge is to have grids[68] with fine enough resolution to capture the influence of thin, high-permeability layers.

- Post-injection monitoring plans that vary in time and location based on the evolving risk at the storage site are as effective and significantly less costly than static monitoring plans based on a fixed time. Assessing case studies over a range of site characteristics and operational conditions, the NRAP initiative has found that the risk-related behavior of a storage site changes significantly during the 10-year time period after injection stops, meaning that effective monitoring plans can vary spatially and temporally.

- The most likely leakage-related scenarios result in small impacts. Further, with respect to aquifer impacts, many modeled leakages result in changes to groundwater that are below detection limits—in other words, below a no-impact threshold. Exceptions to this would be large leaks that could be readily detected during the injection phase of an operation.

- Leakage pathways in wellbores completed with Portland-based cements are likely to self-seal over time due to a combination of geochemical and geomechanical processes. However, other leakage pathways in wellbores could come from fatigue in the continuous cement and casing caused by the CO_2 injection mode, thermodynamic effects, etc.

B. Stakeholder Acceptance of Storage Security

Public support for CO_2 storage projects is of paramount importance at every level, from the local community to elected regional and state officials, and nongovernmental organizations interested in energy and climate solutions.[69] Community communications, outreach, and education can set the tone for the life of the project. Additional information about the importance of stakeholder engagement is discussed in Chapter 4, "Building Stakeholder Confidence," in Volume II of this report.

C. Subsurface Pressure Management

The amount of CO_2 that needs to be sequestered for CCUS to have a meaningful impact on reducing emission could cause widespread pressure increases in the subsurface. Injecting large quantities of fluids (wastewater or CO_2) into the subsurface increases reservoir pressure, which could potentially compromise CO_2 containment, cause induced seismicity risk, and have a significant economic impact on a CCUS project. It is recognized that excessively large pressure increases in a reservoir might create new fractures or reactivate preexisting ones with the associated risk of induced seismicity or leakage. Furthermore, it can also limit the total capacity of the reservoir or the amount of CO_2 that can be injected per well.[70]

Extracting brine from a conventional storage formation is one potential option as a pressure management strategy that could reduce pressure

68 A reservoir model can be used to represent the physical space of the reservoir by defining an array of discrete cells, delineated by a grid that may be regular or irregular. This grid array of cells is usually three-dimensional, although 1D and 2D models are sometimes used.

69 De Coninck, H., and Benson, S. M. (2014). "Carbon Dioxide Capture and Storage: Issues and Prospects." *Annual Review of Environment and Resources*, 39, 243-270.

70 Rutqvist, J. (2012). "The Geomechanics of CO_2 Storage in Deep Sedimentary Formations." Geotechnical and Geological Engineering, 30, 525–551, https://doi.org/10.1007/s10706-011-9491-0.

Zoback, M. D., and Gorelick, S. M. (2012). "Earthquake triggering and carbon sequestration." *Proceedings of the National Academy of Sciences*, 109 (26): 10164-10168, doi: 10.1073/pnas.1202473109.

Chiaramonte, L., White, J. A., and Trainor-Guitton, W. (2015). "Probabilistic geomechanical analysis of compartmentalization at the Snøhvit CO_2 sequestration project." *Journal of Geophysical Research Solid Earth*, 120, 1195–209, doi: 10.1002/2014JB011376.

Buscheck, T. A., Bielicki, J. M., Edmunds, T. A., Hao, Y., Sun, Y., Randolph, J. B., and Saar, M. O. (2016). "Multifluid geo-energy systems: Using geologic CO_2 storage for geothermal energy production and grid-scale energy storage in sedimentary basins," *Geosphere*, 12 (3): 678–696, doi: https://doi.org/10.1130/GES01207.1.

Jahediesfanjani, H., Warwick, P. D., and Anderson, S. T. (2017). "3D Pressure-limited approach to model and estimate CO2 injection and storage capacity: saline Mount Simon Formation." *Greenhouse Gases: Science and Technology*, 7, 1080-1096, doi: 10.1002/ghg.1701.

Jahediesfanjani, H., Warwick, P. D., and Anderson, S. T. (2018). "Improving pressure-limited CO_2 storage capacity in saline formations by means of brine extraction." *International Journal of Greenhouse Gas Control*, vol. 88, 299-310, https://doi.org/10.1016/j.ijggc.2019.06.009.

buildup and might also help manage CO_2 plume migration and aerial extent—which impacts monitoring, verification, and accounting costs—and eventually provide desalinated or treated water for diverse uses.[71]

Pressure management has been implemented as part of the Gorgon project in Western Australia. Reservoir engineers identified that the number of potential CO_2 injection wells suggested for the project could be reduced by incorporating an active reservoir pressure management system. This involves extracting formation water from the Dupuy Formation at locations within pressure communication of the injection area but outside the range of the forecast CO_2 plume migration. The project includes four water production wells that will pump water from the Dupuy Formation using electrical submersible pumps. To reduce environmental impacts, that produced water will be reinjected into the overlying Barrow Group by two water disposal wells. It is expected that this system will produce approximately 60,000 to 80,000 barrels of water per day from the Dupuy Formation. That off-take rate was included in the reservoir simulations used to determine the CO_2 injection well count.[72]

However, in large-scale CCUS projects the magnitude of brine extraction necessary might lead to considerable water management and economic challenges. Aside from the Gorgon Project, for which CO_2 injection and storage started in August 2019, knowledge about the benefits and challenges of brine extraction comes from research studies and a few pilot projects, such as the DOE Brine Extraction Storage Test effort, which will extract brine for pressure management and test various treatment options to produce water suitable for surface use.[73]

Several strategies have been proposed regarding brine extraction as an approach for pressure management. These strategies include preproduction of brine before injecting CO_2 to increase reservoir capacity,[74] simultaneous brine extraction and CO_2 injection to maintain decreased pressure,[75] and brine extraction at specific critical locations (i.e., near faults) to minimize seismicity risk.[76]

71 Buscheck, T. A., Bielicki, J. M., Edmunds, T. A., Hao, Y., Sun, Y., Randolph, J. B., and Saar, M. O. (2016). "Multifluid geo-energy systems: Using geologic CO_2 storage for geothermal energy production and grid-scale energy storage in sedimentary basins." *Geosphere*, 12 (3): 678–696. doi: https://doi.org/10.1130/GES01207.1.

Buscheck, T. A., Sun, Y. W., Hao, Y., Wolery, T. J., Bourcier, W., Tompson, A. F. B., et al. (2011). "Combining brine extraction, desalination, and residual-brine reinjection with CO_2 storage in saline formations: Implications for Pressure Management, Capacity, and Risk Mitigation." *Science Direct*, 4, 4283-4290, http://dx.doi.org/10.1016/j.egypro.2011.02.378.

Klapperich, R., Cowan, R., Gorecki, C. D., Bremer, J. M., Holubnyak, Y., Kalenze, N. S., Knudsen, D. J., Saini, D., Botnen, L. S., LaBonte, J. L., Stepan, D. J., Steadman, E. N., Harju, J. A., Basava-Reddi, L., and McNemar, A. (2013). "IEAGHG Investigation of Extraction of Formation Water from CO_2 Storage." *Energy Procedia*, 37, 2479-2486, doi: 10.1016/j.egypro.2013.06.129.

Newmark, R. L., Friedmann, S. J., and Carroll, S. A. (2010). "Water Challenges for Geologic Carbon Capture and Sequestration." *Environmental Management*, 45, 651–661, https://doi.org/10.1007/s00267-010-9434-1.

Hunter, K., Bielicki, J. M., Middleton, R., Stauffer, P., Pawar, R., Harp, D., and Martinez, D. (2017). "Integrated CO_2 storage and brine extraction." *Energy Procedia*, 114, 6331-6336, https://doi.org/10.1016/j.egypro.2017.03.1769.

72 Trupp, M., Frontczak, J., and Torkington, J., "The Gorgon CO2 Injection Project – 2012 Update," *Energy Procedia*, vol. 37, 2013, p. 6237-6247, http://www.sciencedirect.com/science/article/pii/S1876610213007959.

73 Office of Fossil Energy, "Energy Department Selects Projects to Demonstrate Feasibility of Producing Usable Water from CO2 Storage Sites," https://www.energy.gov/fe/articles/energy-department-selects-projects-demonstrate-feasibility-producing-usable-water-co2. (Accessed January 15, 2019.)

74 Buscheck, T. A., Bielicki, J. M., White, J. A., Sun, Y., Hao, Y., Bourcier, W. L., Carroll S. A., and Aines, R. D. (2016). "Pre-injection brine production in CO_2 storage reservoirs: An approach to augment the development, operation, and performance of CCS while generating water." *International Journal of Greenhouse Gas Control* 54: 499–512.

75 Bergmo, P. E. S., Grimstad, A.-A., and Lindeberg, E., "Simultaneous CO_2 injection and water production to optimize aquifer storage capacity." *International Journal of Greenhouse Gas Control* 2011;5: 555–64.

Buscheck, T. A., Sun, Y., Hao, Y., Wolery, T. J., Bourcier, W. L., Tompson, A. F. B, Jones, E. D., Friedmann S. J., and Aines, R. D. (2011). "Combining brine extraction, desalination, and residual-brine reinjection with CO_2 storage in saline formations: Implications for pressure management, capacity, and risk mitigation," *Energy Procedia*, vol. 4, p. 4283-4290.

Buscheck, T. A., Sun, Y., Chen, M., Hao, Y., Wolery, T. J., Bourcier, W. L., et al. "Active CO_2 reservoir management for carbon storage: Analysis of operational strategies to relieve pressure buildup and improve injectivity." *International Journal of Greenhouse Gas Control* 2012 6:230–45. doi:10.1016/j.ijggc.2011.11.007.

Bourcier W. L., Wolery, T. J., Wolfe, T., Haussmann, C., Buscheck, T. A., and Aines, R. D., "A preliminary cost and engineering estimate for desalinating produced formation water associated with carbon dioxide capture and storage." *International Journal of Greenhouse Gas Control* 2011; 5: 1319–28. doi:10.1016/j.ijggc.2011.06.001.

76 Kroll, K. A., Buscheck, T. A., White, J. A., and Richards-Dinger, K. B. (2018). "Active Pressure Management as a Tool to Reduce Induced Seismicity," Seismological Society of America, 2018 Seismology of the Americas Meeting, 14–17 May 2018, Miami, Florida.

Similarly, several uses for the produced brine have been proposed that include desalination and treatment, reinjection in overlying or underlying saline formations, or disposing of it in the sea. Identified options for the treated brine include offsetting water requirements for CO_2 capture, using for power plant cooling water, and using in agriculture or industrial settings, such as for lithium extraction.[77]

Challenges associated with the use of brine extraction techniques include the cost of additional wells for brine extraction, brine disposal, and the cost of desalination and treatment that will be essential for surface usage. However, this impact could be offset by additional revenue from brine reuse. Some studies suggest that for certain locations, almost the same brine volume as the injected CO_2 volume needs to be removed to prevent induced seismicity.[78] If this much brine were reinjected back into the subsurface in a seismically vulnerable area, this in and of itself would create concerns.

In summary, while brine extraction may be necessary or desirable for some locations, significant challenges remain, and more research is needed to assess the viability of brine extraction as a means of pressure management.

D. Matching a Source to a Sink

CO_2 source-sink matching involves pairing a stationary CO_2 emitter with a potential reservoir. This includes geologic formations such as depleted oil or gas reservoirs, potentially unmixable coal seams, saline formations, and unconventional resource reservoirs. In practice, potential storage sites will have limitations on both CO_2 storage capacity and injection rate that are subject to geological characteristics. Factors considered for appropriate pairing include distance from source to sink, availability of existing CO_2 pipelines to transport supercritical CO_2, depth and geologic attributes of the sink, population distribution near proposed projects, proximity to parks or public lands, and vulnerability of the overlying environment. It is also important to consider social factors—population distribution, community sentiment, private and municipal water supplies, regional environment, and protected areas. Utilizing regional storage hubs could provide value with multiple sources accessing one regionally significant sink.

The main issue associated with source-sink matching is the cost of transport to the storage site. Models for source-sink matching include integer linear programs, vector data-based multi-source technics, raster data-based single-source, and sink-matching models. Based on such models, a decision support system is developed that considers the influence of several factors: reservoir capacity, geometry, injection pressure, sealing formation attributes, vertical proximity of USDWs, potential for enhanced oil or gas recovery, complex terrain factors (such as the slope of the terrain, bypassing urban areas and national parks, and crossing rivers, railways, or highways to find the lowest cost pathway between source and sink), population density, ownership, and social and political data.

Applying Big Data Analytics tools to decrease storage costs and de-risk a project requires highly detailed databases in a data structure that fits the computational models. NETL has developed the National Carbon Sequestration Database to facilitate the use of analytics to aid in source-sink matching. NETL has also funded programs to advance these analytical tools. The potential for reducing the overall costs of CCUS can be significant with respect to the identification of geologic sinks in proximity to the CO_2 emitting sources, which have been identified in several of the DOE's CarbonSAFE and RCSP program projects. Continuing and expanding these efforts and providing potential operators access to these data will have help to accelerate the development of CCUS projects. Furthermore, the Internal Revenue Service Section 45Q tax credit has considerable influence on the cost effectiveness of CCUS projects where source-sink matching is concerned.

E. Pore Space Legal Rights

Before injecting CO_2 for geologic storage, the operator must own the pore space, have permission from the owner, or otherwise have the

77 See footnote 71.

78 Kroll et al. (2018).

right to use the pore space. Therefore, the project developer will have to acquire the authorization to access and use pore space to avoid liability for subsurface trespass and nuisance before a geologic CO_2 storage field can be developed. A detailed discussion related to pore space and the challenges related to the development of a commercial-scale storage project is provided in Chapter 3, "Policy, Regulatory, and Legal Enablers," in Volume II of this report.

F. State Primacy

The EPA regulates subsurface injection to protect USDWs via the Safe Drinking Water Act's UIC program. In 2010, the EPA developed UIC Class VI rules for wells used to inject CO_2 specifically for the purpose of long-term geologic storage. These Class VI rules cover items such as CO_2 injection and site characterization, well permitting, well construction and operational standards, testing, plugging, recordkeeping, corrective action, emergency and remedial response, closure and post-closure care, and associated financial assurance requirements.

The Class VI regulations can be implemented by the EPA or adopted by states, territories, or tribes as the primary enforcement authority. Designation of this authority outside of the EPA is called primacy. Primacy authorizes a state, territory, or tribe to implement regulatory responsibilities associated with the UIC program. States must apply for primacy and be granted authority through EPA review and rulemaking.

In 2013, North Dakota became the first state to seek primacy from the EPA for the Class VI UIC program and was granted authority in July 2017. The North Dakota Industrial Commission amended its own carbon sequestration rules to align with the federal regulations. In 2019, the only other state perusing primacy for the Class VI program was Wyoming. The state of Wyoming filed its application for Class VI primacy with the EPA in Region 8 on January 2018 through the Wyoming Department of Environmental Quality. As of April 2019, that application is still pending, and no additional information is available.

The benefits of state primacy for the Class VI UIC program are numerous. However, because there is little funding available from the EPA for state UIC programs, there is limited incentive for states to take primacy for the Class VI program. It would be helpful if states had access to information about the benefits of receiving Class VI primacy, the process and experience of states that have primacy for other well classes, and financial support for developing a Class VI primacy application and implementing the program for commercial projects.

A more detailed discussion of state primacy and its implications is discussed in Chapter 3.

V. CROSSCUTTING ISSUES FOR CO_2 EOR AND CO_2 STORAGE

Storage projects can be broadly divided into two types. Dedicated CO_2 storage involves the underground injection of anthropogenic CO_2 (from industrial sources) for the sole purpose of GHG mitigation. Incidental or associated storage occurs when CO_2 is injected for other purposes, such as CO_2 EOR.

It is important to note that in the United States, less than 30% of the CO_2 used for CO_2 EOR is from anthropogenic sources; the remainder comes from natural sources. There have been more than 100 commercial CO_2 EOR projects in the United States since the 1970s, and experience has shown that CO_2 EOR produces incremental oil and permanently traps CO_2.

In contrast, dedicated CO_2 storage is a relatively nascent industry with a few commercial-scale projects operating around the world—those storing more than approximately 0.5 Mtpa of CO_2. Although incidental or associated storage is a physical consequence of EOR, operators of such sites might not seek recognition of GHG mitigation benefits because of various economic, regulatory, or legal factors. CO_2 EOR projects are driven by the economic benefit of producing oil that may not be recoverable by primary production methods. Historically, the trapping of CO_2 has been a result of the CO_2 EOR process, rather than an explicit objective of the CO_2 EOR process. During CO_2 EOR operations, CO_2 is produced with the recovered oil, separated and purified, and reinjected for additional oil recovery. The result of this closed-loop CO_2 system is that associated storage infrastructure requirements tend to be more complex than those for dedicated storage, which does not include oil production.

Although the primary goals of dedicated and associated storage may be different, the two do share several key crosscutting aspects. Both dedicated and associated storage result in the secure storage of anthropogenic CO_2, providing mitigation for GHG emissions. Both require similar geologic conditions, engineering approaches, monitoring technologies, and social license to operate. With respect to geologic conditions, both types of storage require reservoir rocks with enough injectivity and storage capacity to support commercial-scale CO_2 injection. Thick, sealing rocks are also necessary for both types of storage to ensure that the injected CO_2 does not migrate outside of the permitted zone. Subsurface engineering approaches and requirements for drilling, operating, and maintaining wells are similar and the technologies and protocols used are essentially interchangeable. Many surface infrastructure elements—pipelines, compressors, wellheads, and Supervisory Control and Data Systems—are also largely the same, regardless of whether they are for associated or dedicated storage. Monitoring the injection of CO_2 and its subsequent movement in the subsurface is an essential component of both CO_2 EOR and dedicated storage projects.

While general principles and technologies are common to dedicated and associated storage, site-specific factors will always impart unique qualities to each project. Dedicated storage sites have significantly fewer well penetrations compared with associated storage via CO_2 EOR. It is also important to note that there are differences between CO_2 storage and EOR categories, particularly with respect to monitoring and tax incentives. CO_2 EOR operators tend to refer to monitoring as reservoir surveillance, while dedicated storage operators call it monitoring, verification, and accounting. Regardless of the terminology, the technologies used to determine the disposition of the injected CO_2 are largely the same.

There are, however, striking differences between associated and dedicated storage in terms of the regulatory requirements for monitoring and how the data generated by those activities are used. For EOR operators, the primary purpose of gathering monitoring data is to better understand the efficiency of their operation, typically in terms of CO_2 utilization rates measured in units of CO_2 (either purchased or injected) per unit of oil. Monitoring for dedicated storage places more emphasis on determining the areal extent and geometry of the CO_2 plume and detecting any movement of CO_2 out of the designated storage zone. Both CO_2 EOR and dedicated storage projects use monitoring technologies, such as wellhead pressure gauges, to ensure safe operations and reduce operational risk.

In addition to sharing monitoring approaches and technologies, there are also important crosscutting aspects between saline storage and EOR that result from operations in stacked reservoirs. Operations in stacked reservoirs occur when CO_2 is injected into saline reservoirs that are above or below oil reservoirs. The surface infrastructure constructed for development of the oil field, especially that which is used for CO_2 EOR, can be used for saline storage projects in reservoirs that are above or below the oil reservoir. The geological characterization that has been used to develop the oil resources (data from well logs and seismic surveys) will give a saline storage project a detailed understanding of critical properties such as reservoir depth, thickness, and architecture at the earliest stages of the project. This will always be the case for saline resources above an oil reservoir, and sometimes the case for saline resources below an oil reservoir, although there are typically fewer wells that penetrate below any given oil reservoir. Dedicated storage projects in saline reservoirs below oil fields must contend with challenges from drilling through the oil reservoir, including zones of abnormal pressure conditions (higher or lower pressures than expected) and ensuring that well drilling and completion operations do not inadvertently damage the oil reservoir. There are also challenges when distinguishing multiple overlapping CO_2 plumes in zones above or below an active CO_2 EOR project. Advancements in monitoring technologies, including improvements in geophysical and acoustic data acquisition and processing, are needed to address those challenges.

In some instances, a dedicated storage project may be conducted in the same rock formation as the oil reservoir, but in a water-saturated zone that is geologically downdip from the main area of oil saturation, that is in the reservoir's "water leg." Like saline storage resources above and below an oil reservoir, dedicated storage in the water leg of an oil reservoir can benefit from, and dovetail with, the infrastructure, characterization, and monitoring elements of a nearby CO_2 EOR project. However, migrating the injected CO_2 from the water leg into the oil reservoir will complicate CO_2 monitoring and accounting for both the dedicated storage project and the CO_2 EOR project, which can lead to complications in the certification of storage by government agencies and qualification of Section 45Q tax credits. CO_2 storage in stacked reservoirs and water leg reservoirs may also face challenges from pore space ownership and mineral lease issues. Clarifying existing state and federal policies and regulations and, in some cases, new legislative directives that address the crosscutting aspects of dedicated storage and CO_2 EOR, may be necessary.

VI. RESEARCH AND DEVELOPMENT NEEDS

Ramping up global CO_2 storage in geologic formations to a scale of gigatonnes per year is an enormous task. For example, increasing global storage of CO_2 to 1 Gt/year—a scale equivalent to approximately 40% of United States stationary source CO_2 emissions—would require a fifteenfold increase beyond the CO_2 EOR and storage operations that exist around the world in 2019. There is already a broad level of technical expertise from more than 20 years of CO_2 storage experience and 100 years of oil and natural gas operations to increase the number of geologic storage projects in oil and natural gas reservoirs and saline formations.

However, for global CO_2 storage to expand to a 1 Gt CO_2/year level and beyond, much more intensive use of storage resources will be necessary, requiring better information to assess risks, to inform site characterization and source-sink matching, and providing assurances that permanent storage will be safe and secure. The 2018 NASEM report on CO_2 Removal and Secure Sequestration and the International Initiative Mission Innovation Workshop on CO_2 Capture and Sequestration, provide comprehensive assessments of research needs. In this chapter, the focus is on those R&D needs that will support the rapid scale-up of CO_2 storage in geologic formations in the United States.

Globally, there is a significant amount of experience from the previously cited CO_2 storage projects injecting at the scale of 1 Mt/year, and there are several other projects at a smaller scale. There are distinct challenges to rapidly increasing the number of large-scale CCUS projects in the United States, such as how the presence of multiple CO_2 storage projects in a single basin might interact with each other through overlapping pressure buildups and CO_2 plume comingling and the continued research about the commercial viability of using unconventional formations (shale, basalt) for large-scale CO_2 injections.

Figure 7-9 presents a sketch providing a spatial comparison to illustrate the extent to which injecting CO_2 into a saline formation causes pressure buildup in the formation and the area surrounding it. The individual footprint of a CO_2 plume in a saline formation may extend 30 km^2 to 300 km^2, but the area in which pressure buildup occurs is even larger. If there are multiple CO_2 injection projects within the same saline formation, the pressure buildup from the projects will be additive, extending the buildup over a larger area.

Given the need to address the challenges, research priorities include:

- Increasing the efficiency of site characterization and selection methods
- Increasing pore space utilization by improving confidence in CO_2 plume immobilization mechanisms and accelerating their speed in immobilizing CO_2
- Improving coupled models for optimizing and predicting CO_2 flow and transport, geomechanics, and geochemical reactions, including leveraging capabilities in the oil and natural gas industry
- Lowering the cost of monitoring and developing new monitoring technologies

- Quantifying and managing the risks of induced seismicity
- Investigating the feasibility of Mt/year storage in alternatives to sandstone and carbonate reservoirs, including ultramafic rocks (basalt) and low-permeability rocks (shale)
- Conducting social sciences research for improving stakeholder engagement and informing the public about the need, opportunity, risks, and benefits of CO_2 storage in geologic formations.

These research activities will address many of the practical and financial challenges facing operators who are contemplating new large-scale storage projects. Table 7-4 details how the proposed research activities address these needs. Current R&D programs address the needs of fundamental storage science, storage site characterization and drilling, and pilot- and demonstration-scale CO_2 injection projects. Combining additional pilot and demonstration projects with CO_2 storage R&D will help the nascent CO_2 storage industry achieve at-scale deployment in the United States. These projects would also establish valuable infrastructure during the R&D phase that could then be used for commercial-scale deployment.

It is recommended that an increase of the current DOE R&D budget for geologic storage by $400 million per year for the next 10 years could be allocated as follows:

- $80 million to the Regional Initiative to Accelerate CCUS Deployment (for a total appropriation of $100 million per year)
- $100 million for characterization of geologic storage formations, including offshore, that have scale potential through the CarbonSAFE program or similar initiatives (for a total appropriation of $150 million per year)
- $220 million per year to enable field-scale projects that collect data and geologic samples used to advance the science of long-term CO_2 storage security.

These R&D activities also play a critical role in increasing the industrial workforce needed to carry out these activities.[79] These projects should also provide a testing opportunity for monitoring and predictive modeling of CO_2 in the subsurface at-scale.

79 National Academies of Sciences, Engineering, and Medicine. (2018). *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda.* Washington, DC: The National Academies Press, 356 p., https://org/10.17226/25259.

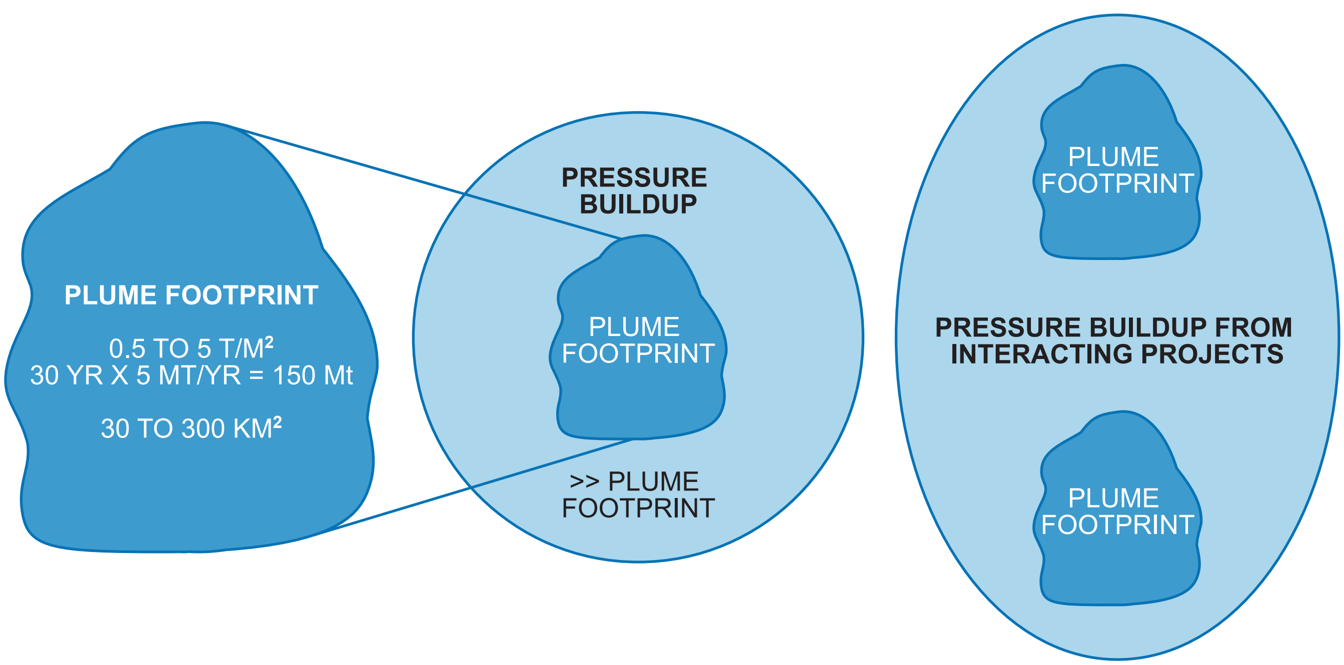


Figure 7-9. *Spatial Comparison of a CO_2 Plume and Area of Pressure Buildup it Affects*

Project Phase / R&D Needs	Site Characterization, Selection, and Engineering	Operations	Closure and Post-Closure Site Care
Reliable site characterization (seals, faults, trapping, heterogeneity)	• Confidence in seal integrity • Accurate assessment of plume footprint • Injection well design and optimization		• Accurate site geologic model for post-injection CO_2 migration and pressure recovery
Lower costs of monitoring	• Risk-based monitoring design tailored to site specific requirements	• Cost optimal monitoring and awareness of plume footprint and pressure buildup	• Monitoring to support risk-based duration of post-closure site care
Plume immobilization, quantification, and acceleration	• Accurate assessment of plume footprint • Optimize injection and operational design to limit footprint	• Reduced CO_2 footprint lowers monitoring costs and project risks	• Shorten the time to CO_2 immobilization • Reduce duration of post-closure site care
Risks to groundwater	• Assess and mitigate risks to groundwater from CO_2 and brine leakage • Contingency plans for unanticipated leakage	• Mitigation plans for unexpected leakage	• Confidence in long-term groundwater protection
Induced seismicity science and mitigation	• Avoid or mitigate seismic risks through site selection and project design • Contingency plans for unexpected seismicity	• Mitigation plan for unexpected induced seismicity	
Better simulation models for lifecycle plume migration and trapping	• Accurate assessment of plume footprint • Optimize injection and operational design to limit CO_2 footprint and pressure buildup	• Rapid and accurate model calibration with monitoring data • Update operational design based on monitoring data	• Accurate prediction of post-closure CO_2 migration and pressure recovery to support risk-based site closure
Alternatives to conventional storage (shale, basalt, coal)	• Expand range of storage options for improved source-sink matching	• Operational parameters optimized to characteristics of unconventional reservoirs	• Risk-based post-injection monitoring and site care

Table 7-4. *Research Needs for Different Phases of a Geologic CO_2 Storage Project*

VII. PRIORITIES FOR ACHIEVING AT-SCALE DEPLOYMENT OF CCUS

This study has identified three phases projected to occur over a 25-year period to achieve at-scale deployment of CCUS in the United States—activation phase, expansion phase, and at-scale phase. Each phase is defined by the primary actions that need to occur within a relative timeframe, including near-term, mid-term, and long-term priorities. The phases and their priorities are based on the abatement cost curve analysis presented in Chapter 2, "CCUS Supply Chains and Economics," in Volume II of this report.

A. Near-Term Priorities for the Activation Phase

1. Increased Funding for R&D

As of October 2019, there were 19 large-scale CCUS projects operating around the world with a total storage capacity of about 32 Mtpa of CO_2. Ten of these projects are in the United States with a total storage capacity of 25 Mtpa. Enabling an additional 25 Mtpa to 40 Mtpa of CO_2 storage during the next 5 to 7 years of the CCUS activation phase would require doubling the current R&D budget for geologic sequestration to about $250 million/year short-term research priorities include:

- Increasing the efficiency of site characterization and selection methods
- Increasing pore space utilization by improving confidence in CO_2 plume immobilization mechanisms and accelerating their speed in immobilizing CO_2
- Improving coupled models for optimizing and predicting CO_2 flow and transport, geomechanics, and geochemical reactions, including leveraging capabilities in the oil and natural gas industry
- Lowering the cost of monitoring and developing new monitoring technologies
- Quantifying and managing the risks of induced seismicity
- Investigating the feasibility of Mt/year storage in alternatives to sandstone and carbonate reservoirs, including ultramafic rocks (basalt) and low-permeability rocks (shale)
- Conducting social sciences research for improving stakeholder engagement and informing the public about the need, opportunity, risks, and benefits of CO_2 storage in geologic formations.

Table 7-4 details how the proposed research activities address the needs of each phase of a geologic storage project to illustrate how it will benefit industry operators. For example, new methods for using the available pore space more efficiently will reduce the cost of characterizing a site by limiting the area that must be characterized. During the operational phase of a project, high-reliability and low-cost monitoring programs that are targeted to the largest project-specific risks will increase stakeholder confidence that groundwater resources are protected, and site-workers and the public are safe. For the closure and post-closure phase, proven models for predicting the long-term behavior of stored CO_2 will help to shorten the post-closure site care period by providing tools for the operator to demonstrate that USDWs would not be endangered after the injection period stops. In addition to providing valuable knowledge, university-based research programs will ensure a pipeline of qualified talent to increase the workforce capacity that will be needed to support the scale-up of CO_2 capture and storage operations.

2. Class VI Permit Reform

Some aspects of the Class VI regulations for CO_2 storage are problematic for increased adoption of CCUS. Improvements and reform of Class VI regulations include optimizing permit process efficiency to shorten the time it takes to obtain a permit by improving the level of coordination between the permit applicant and the regulatory authority that grants the permit. Other potential improvements to the regulatory process include adopting risk-based monitoring approaches, clarifying that site closure is allowed when drinking water aquifers are no longer endangered, providing flexibility for CO_2 plume tracking requirements, adopting a risk-based approach for the post-closure monitoring period, subdividing the area of review into two regions (one for the CO_2 plume and one for the pressure buildup), and developing an approach for defining the area of review for naturally over-pressured storage reservoirs. These issues are discussed in more detail in Chapter 3.

3. Section 45Q Tax Reform and Clarification

The FUTURE Act passed as part of the 2018 budget appropriation provides a tax credit of $50/tonne (by 2026) of CO_2 stored in a saline formation. The Section 45Q tax credit has the potential to dramatically increase deployment of CO_2 storage in the United States. However, several issues must be addressed, including: clarifying what is required to demonstrate "secure geologic storage;" establishing regulations for recapturing the credit if the CO_2 ceases to be properly captured, disposed of, or reused as a tertiary injectant; and providing developers with clarity, either through regulation or guidance, on what constitutes "beginning of construction." Section 45Q is discussed in more detail in Chapter 3.

4. Access to Onshore Federal Lands

One of the hurdles for owners of stationary sources of CO_2 who want to implement commercial-scale geologic storage is securing a sufficiently large tract of land and associated subsurface pore space to develop a geologic storage site. Federal lands present a unique opportunity to achieve this due to single ownership of large, continuous acreage, a large portion of which contains formations with ample CO_2 storage capacity. The estimated CO_2 storage capacity beneath federal lands ranges between 126 and 375 Gt. New regulations and processes are needed to enable use of federal lands for CO_2 storage. These issues are also discussed further in Chapter 3.

B. Medium-Term Priorities for the Expansion Phase

1. R&D and Workforce Capacity

The expansion phase could enable an additional 75 to 85 Mtpa of CO_2 storage within the next 15 years. Research that addresses medium-term priorities will be needed to address the gaps in knowledge that emerge as the CCUS industry begins to grow. Continued advances in data science, machine learning, advanced sensing, and other innovations are likely to benefit CO_2 geologic storage. Research programs at universities will increase the workforce of engineers, geoscientists, and other disciplines with the level of technical expertise needed to support the increasing number of CO_2 storage projects and supporting infrastructure that will be developed during the 15 years of the Expansion Phase.

2. State Primacy

The EPA and, in some cases the states, have the permitting authority and oversight of the Class VI program. Approval of primary enforcement responsibility to the states is termed primacy. States either incorporate the federal standards by reference or develop their own state regulations for approval by rule through the EPA. There are many benefits to establishing state primacy, which includes aligning state objectives, improved coordination of the Class VI program, leveraging state experience, and establishing a business advantage. However, because there is minimal funding available from the EPA (as appropriated by Congress) for all state UIC programs, there is little funding incentive for states to take primacy for the Class VI program. It would be beneficial if funding was increased and used to develop a Class VI primacy application and program for commercial-scale projects. It would also be helpful if states had access to information about the benefits of receiving Class VI primacy, the process, and experience of states that have primacy for other well classes.

3. Pore Space Legal Rights

Before injecting CO_2 into the subsurface for geologic storage, the operator must own the pore space, have permission from the owner, or have the right to use the pore space. The laws concerning property rights are a basic concern of state law rather than federal law. Pore space ownership is rooted in the ad coelom doctrine where "the ownership of land may be divided horizontally, vertically or otherwise either above or below the ground." The issue of pore space legal rights is complicated by the fact that for a large CO_2 storage project, the CO_2 plume may extend over hundreds of square miles, and the pressure buildup extends over an even larger area. For large projects, including those identified as CO_2 storage hubs where multiple property and pore space owners are likely to be involved in the process of acquiring pore spaces rights, resolving issues related to property rights and competing uses of the subsurface could have a large impact on the commercial viability of CO_2 storage. It is recommended that federal and state governments coordinate to establish a process for permitting the access and use of pore space for geologic storage projects on privately owned lands.

C. Long-Term Priorities for the At-Scale Phase

1. Access to Conventional Offshore Formations

The at-scale phase increases total U.S. storage capacity from CCUS to approximately 500 Mtpa within the next 25 years. This level of storage would require access to conventional offshore formation. The OCS includes submerged lands under the jurisdiction of the federal government and coastal states. Some of the benefits of offshore CO_2 storage include the fact that it is managed by state and federal entities rather than private landowners. There is also extensive oil and natural gas experience in the Gulf of Mexico that is transferable to CO_2 storage, and existing oil and natural gas infrastructure could be repurposed for CO_2 storage. Offshore storage also puts few or no USDWs at risk, and pressure management of the formation by extracting brine is likely easier. Finally, geologic and geophysical surveying for monitoring offshore storage may be subject to fewer impediments due to the lack of numerous structures and landowners. Offshore storage could be enabled by requirements for monitoring for the life of the project but designed in a manner that facilitates the ease of site closure after storage operations terminate.

2. Continued R&D and Workforce Capacity Development

Like the expansion phase, research that addresses the long-term priorities of the at-scale phase will be needed to address the gaps in knowledge that emerge as the CCUS industry continues to grow. Continued advances in data science, machine learning, advanced sensing, and other innovations are likely to benefit CO_2 geologic storage. Research programs at universities will increase the workforce of engineers, geoscientists, and other disciplines with the level of technical expertise needed to support the increasing number of CO_2 storage projects and supporting infrastructure that will be developed during the 25 years of the at-scale phase.