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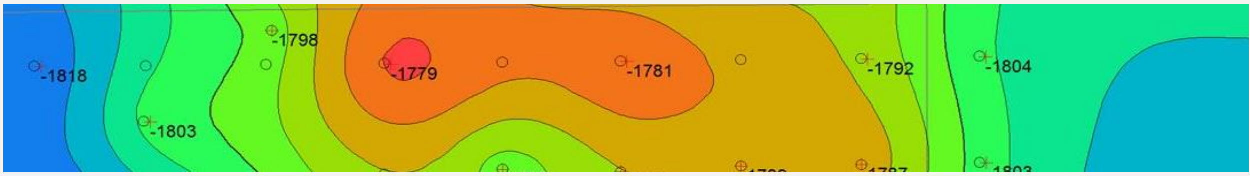

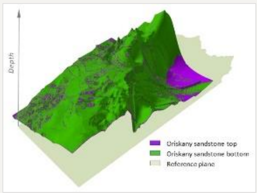

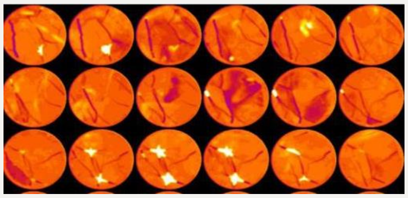

CO_2 Leakage During EOR Operations – Analog Studies to Geologic Storage of CO_2

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LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

3-D	Three-dimensional
ADM	Archer Daniels Midland Company
AMA	Active monitoring area
AoR	Area of review
API	American Petroleum Institute
ARI	Advanced Resources International, Inc.
atm	Atmosphere
bbl/d	Barrels per day
BPLB	Big Piney-LaBarge field
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	Carbon capture and storage
CFR	Code of Federal Regulations
CH_4	Methane
cm^3	Cubic centimeter
CO_2	Carbon dioxide
cP	Centipoise
CREAM	CO_2 Resources Evaluation Analytical Model
D	Darcy
Denbury	Denbury Resources
DOE	Department of Energy
DOGGR	Division of Oil, Gas, and Geothermal Resources
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERR	Economically recoverable resource
ft	Foot, feet
GHG	Greenhouse gas
GIIP	Gas initially in place
GR	Gamma ray
Gt, Gtonne	Gigatonne, gigatonnes
H_2CO_3	Carbonic acid
H_2O	Water
H_2S	Hydrogen sulfide
HCPV	Hydrocarbon pore volume
He	Helium
IBDP	Illinois Basin Decatur Project
ICCS	Illinois Industrial Carbon Capture and Storage Project
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPAC-CO_2	International Performance Assessment Centre for Geological Storage of CO_2
KCC	Kansas Corporation Commission
kPa	Kilopascal, kilopascals
lb/ft^3	Pound per cubic foot
LNG	Liquified natural gas
m	Meter, meters
m^2	Square meters
Mcf/d	Thousand cubic feet per day
MMcf/d	Million cubic feet per day
mD	Millidarcy
MESA	Mission Execution and Strategic Analysis
MIT	Mechanical integrity test/testing
MMA	Maximum monitoring area
MMP	Minimum miscibility pressure
MMscf/d	Million standard cubic feet per day
MPZ	Main pay zone
MRV	Monitoring, reporting and verification
Mt	Million tonnes
Mt/yr	Million tonnes per year
Mt.	Mount
MVA	Monitoring, verification, and accounting
N/A	Not available
N_2	Nitrogen
NATCARB	National Carbon Sequestration Database and Geographic Information System
NETL	National Energy Technology Laboratory
NPV	Net present value
OCS	Outer Continental Shelf
OIP	Oil in place
OOIP	Original oil in place
OWC	Oil water contact
PBEM	Permian Basin EOR Market

PFT	Perfluorocarbon tracer gas
PISC	Post-injection site care
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
PTRC	Petroleum Technology Research Centre
R&D	Research and development
rcf	Reservoir cubic feet
RCSP	Regional Carbon Sequestration Partnership
ROW	Right-of-way, rights-of-way
ROZ	Residual oil zone
SACROC	Scurry Area Canyon Reef Operators Committee
scf	Standard cubic feet
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SO_2	Sulfur dioxide
TAC	Texas Administrative Code
Tcf	Trillion cubic feet
TD	Total depth
TDS	Total dissolved solids
tonne	Metric ton
TRR	Technically recoverable resource
TWAG	Tapered water alternating gas
TZ	Transition zone
U.S.	United States
UIC	Underground Injection Control
USDW	Underground source of drinking water
USGS	United States Geological Survey
WAG	Water alternating gas
yr	Year
°C	Degrees Celsius
°F	Degrees Fahrenheit
°R	Degrees Rankine

EXECUTIVE SUMMARY

The purpose of this report is to compile a stand-alone body of knowledge regarding historical and current operations of carbon dioxide (CO_2) enhanced oil recovery (EOR), as well as document relevant information pertaining to CO_2 leakage that may have occurred as part of those operations, that may be directly or indirectly relevant to geologic CO_2 storage in saline-bearing formations. This is the third of three planned reports that evaluate analog industries of CO_2 storage (the first focuses on underground natural gas storage, and the second on wastewater disposal using United States [U.S.] Environmental Protection Agency [EPA] Underground Injection Control [UIC] Class I disposal wells). EOR projects inject CO_2 into depleted oil reservoirs to increase recovery of the oil in place as a tertiary production process, usually following extensive primary production and waterflooding-driven production phases. In general, the process involves injecting supercritical CO_2 into a reservoir to reduce the viscosity and surface tension of the residual oil in place, allowing it to flow freely to production wells. Injection of CO_2 into depleted oil and gas reservoirs enables industry to extend oil production and the operational life of oil fields (8 to 20 percent or more of the reservoirs' original oil). [1] The technologies and equipment used to deploy CO_2 EOR parallel those needed for geologic storage of CO_2 in saline-bearing formations (and essentially full-scale carbon capture and storage [CCS]) in many instances. For instance, the two practices face similar technical grand challenges associated with using wells to safely and effectively inject CO_2 into deep, porous geologic formations; but have inherently differing overall objectives. The goal of CO_2 storage in saline-bearing formations is to permanently store large volumes of anthropogenically-derived CO_2 in the subsurface. On the other hand, the objective of CO_2 EOR operations is not to store CO_2, but to maximize oil production. However, some of the injected CO_2 ultimately does get stored in the reservoir as part of the process. [2] Additionally, each practice shares similarities in terms of site screening, selection, and characterization approaches, operational procedures, and infrastructure requirements. Furthermore, both practices have demonstrated, to some degree, success in capturing, transporting, and injecting/storing CO_2 from anthropogenic sources. Therefore, CO_2 EOR operations, which have an extensive operational history, should provide a wealth of knowledge and lessons learned from which CO_2 storage stakeholders in industry, academia, and policy can benefit.

CO_2 EOR is an integral component of U.S. oil production and has been in practice in the United States for over 40 years. This long history has been marked by relatively safe injection of CO_2 into the subsurface. EOR-related injection wells fall under EPA's UIC Program Class II well type. These wells are specifically designed, constructed, and completed with the intent to prevent the movement of fluids that could result in the pollution of an underground source of drinking water (USDW) or leakage to the surface. [3] On the other hand, CO_2 storage is a relatively new and emerging technology which is intended as a short-to-medium term option for significantly reducing the CO_2 emitted into the atmosphere from anthropogenic sources. [4] While CO_2 storage field testing has occurred, continued research is needed to significantly improve the effectiveness of CO_2 storage-related technologies, reduce the cost of implementation, and generate data, best practices, and lessons learned. Like CO_2 EOR, CO_2 storage operations are also regulated under EPA's UIC Program. However, the Class VI well is the UIC well type dedicated specifically for long-term geologic CO_2 storage injection. Like the Class II well, the Class VI well regulations are also based on the protection of USDWs, but they are tailored to account for the unique challenges (like relative buoyancy of CO_2, subsurface mobility, corrosivity in the presence of water while under subsurface pressure and temperature conditions, as well as the large injection volumes anticipated) expected for CO_2 storage operations. [5] Therefore, from a regulatory perspective, both Class II and Class VI wells are designed to protect USDWs, but often have diverging requirements for certain operational and safety objectives pertaining to ensuring well integrity, monitoring for leakage, well siting and construction criteria, fiscal responsibility, and post-closure care.

Despite the difference in prominent UIC well class utilized between the two practices, the long history of CO_2 EOR operations in the United States provides a unique opportunity to examine Class II well evolution and operation in order to: 1) gain insight and lessons learned associated with EOR projects; 2) draw parallels to the subsurface injection governing regulations associated for CO_2 EOR and CO_2 storage; 3) utilize information learned to help guide and inform future geologic CO_2 storage projects in saline-bearing formations; and 4) identify best practices for overcoming critical technical, regulatory, and/or public perception challenges. Experience from CO_2 EOR has demonstrated that large volumes of gas can be stored safely underground and over long timeframes when the appropriate best-practices are implemented. Therefore, storing CO_2 in subsurface geologic formations at commercial-scales should also be feasible if comparable best practices are demonstrated.

In fact, CO_2 storage has indeed been demonstrated globally, to some degree, and at various scales. But, it has not yet been deployed close to the same magnitude of commercial analogs like underground natural gas storage, EOR, or deep well disposal. The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has identified approximately 300 existing, planned, or recently-completed CCS-related projects (ranging from pilot testing to commercial-scale) across the globe; approximately 110 of which received some level of direct support from DOE. Of those projects receiving DOE support, roughly 85 are in the United States. [6] Currently, 37 CCS projects across the globe (some of which include CO_2 EOR operations utilizing captured CO_2 from anthropogenic sources) are of "large-scale;" only 17 of which are currently in operation, while the others are under construction or in development. [7] One approach believed to facilitate wider spread deployment of CO_2 storage (through integrated CCS) in the future is through continued research and development (R&D) support and technology advancement. [8] As CCS technologies and research continue to advance, demonstration projects then become critical for validating that CO_2 capture, transport, injection, and storage can be achieved safely and effectively. Successful demonstration and deployment of CCS technologies can contribute toward building confidence and reducing costs through new innovations and advances in capture, storage, and monitoring technology and protocols. At all levels of R&D (applied R&D through field testing), CCS research can also benefit by drawing lessons from the history of other energy technologies and analog industries that were once considered risky and expensive early in their commercial development. However, building CCS into a key component for managing anthropogenically-derived CO_2 will likely require more than just technological feasibility; it also may require the development of both regulatory and incentive policies to support business models that can enable widespread adoption, will need improved community awareness of the importance and value of CCS, and must enable application to multiple industry types, each with distinctive emission footprints, markets, and costing structures. [8] [9] Therefore, analyzing comparable analogs to CO_2 storage can also provide insight into as to how widespread commercial deployment may have been facilitated or influenced by possible policy and/or regulatory drivers prominent throughout its operational history, as well as materialization of successful business-cases.

Worldwide experience of industrial analogs (e.g., CO_2 EOR) demonstrates that the technology required to capture CO_2, transport it to a storage site, and inject it deep into the ground currently exists and can be applied. This report presents a side-by-side comparison of major synergistic features (such as governing regulations, formation types used, injection approaches, national storage capacity estimates, leakage mitigation strategies, etc.) between Class II CO_2 EOR injection well operations and CO_2 storage in saline-bearing formations using UIC Class VI wells. The findings suggest that Class II CO_2 EOR is a suitable analog that can provide valuable insights to help address technical and policy-related questions concerning geologic CO_2 storage. For instance, Class II and Class VI wells share several risks related to the injection and storage of CO_2. Because of these shared risks, both types have comparable well design requirements and may utilize similar equipment, including pumps, pipelines, and monitoring equipment. [3] [10] [11] Site operators for both Class II and Class VI wells must ensure that geologic reservoirs utilized at injection sites have the necessary capacity for storage, have sufficient injectivity to pump CO_2 into the formation at the desired rate, have sufficient geologic structure to prevent leakage, and that sites are safely constructed, operated, and maintained. In the context of this report, analogs provide examples or case studies that help pinpoint key success factors that are likely to be effective for CO_2 storage, as well as those that should be avoided. Best practices and lessons learned from analog industries can provide perspective from which future CO_2 storage R&D pursuits and field projects can benefit. Additionally, highlighting instance for how analogs to CO_2 storage overcome shared technical grand challenges and address regulatory requirements to achieve commercialization is another critical objective of this report.

1 INTRODUCTION

A balance must be found between preserving energy security and affordability and addressing growing concerns over emitting large volumes of carbon dioxide (CO_2) into the atmosphere. Approximately two-thirds of the anthropogenic (i.e., man-made) CO_2 emissions in the United States (U.S.) come from power generation facilities, industrial facilities (cement plants, ethanol plants, etc.), and residential sources. The other third can be attributed to transportation-derived emissions. [12] Carbon capture and storage (CCS) is one of many emerging strategies for managing or reducing the anthropogenic emissions of CO_2 into the atmosphere.

CCS involves the separation and capture of CO_2 from fossil fuel-based power generation and industrial processes prior to atmospheric release, followed by transport and safe, permanent injection (or beneficial CO_2 reuse and utilization) into deep underground geologic formations with the goal of reducing anthropogenic CO_2 emissions into the atmosphere. CCS can also include beneficial reuse of captured anthropogenically-derived CO_2 as a feedstock for generating products like commercial chemicals, plastics, improved cement, and for use in enhanced oil recovery (EOR). [13] CO_2 capture integrated with transport and geologic storage comprises a suite of technologies that can benefit an array of industries, including the power (fossil, biofuel, and geothermal) and refining industries. Additionally, CCS enables industry to continue to operate while emitting less CO_2, making it a powerful tool for managing anthropogenically-derived CO_2. However, long-term storage of CO_2 in subsurface formations must be safe, permanent, environmentally sustainable, and cost effective.

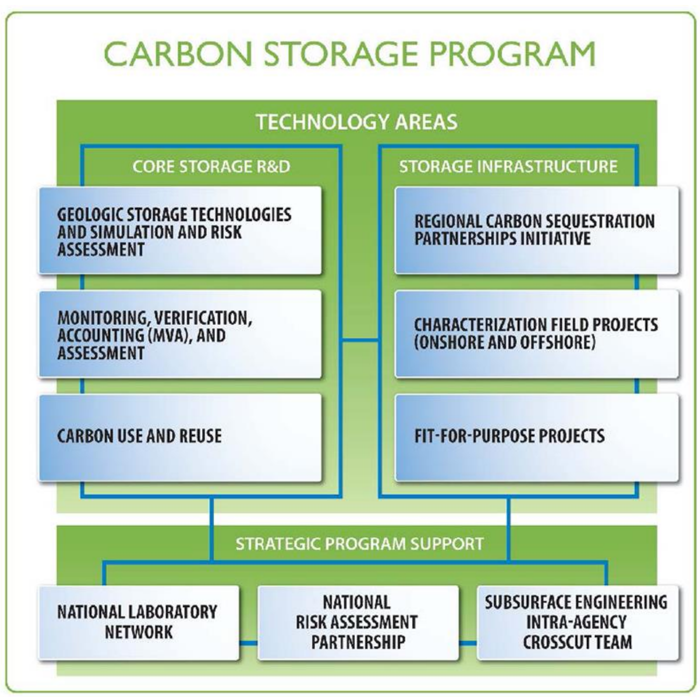
Suitable geologic storage formations can exist in both onshore and offshore settings, and each type of geologic formation presents different opportunities and challenges. [14] While the technologies required for CCS are at various stages of commercial readiness and only a few fully integrated projects that capture and store large volumes of CO_2 are being deployed worldwide, CCS remains an important option for managing anthropogenic CO_2 emissions and providing a bridge to a viable energy future. In addition, current CCS-based regulatory frameworks, particularly in the United States, require researchers to develop a more robust suite of technologies capable of cost-effectively providing useful data and information to CCS operators, policymakers, and other stakeholders to advance the CCS industry closer to commercialization. [15]

1.1 U.S. DOE'S EFFORTS TOWARD ADVANCING CARBON CAPTURE AND STORAGE

Addressing the potential adverse impacts resulting from anthropogenic CO_2 emissions is a top priority for the U.S. Department of Energy (DOE). [14] Particularly, DOE's Office of Fossil Energy (FE) has been developing a portfolio of CCS technologies that can capture, utilize, and permanently store CO_2 from man-made sources. The Carbon Capture Program, administered by FE and the National Energy Technology Laboratory (NETL), is conducting research and development (R&D) activities on Second Generation and Transformational carbon capture technologies with the potential to provide significant reductions in both cost and energy penalty as compared to currently available First-Generation technologies. The Carbon Storage Program, also administered by FE and NETL, is focused on ensuring the safe and permanent storage and/or utilization of CO_2 captured from stationary sources. CO_2 storage in geologic formations has enormous promise in oil and natural gas reservoirs, unmineable coal seams, saline reservoirs, basalt formations, and organic-rich shale basins. [14] The integration of these two programs has placed NETL at the forefront of research to develop safe and cost-effective CCS-related technologies for capture and long-term permanent geologic storage and/or use of CO_2. The technologies developed, and large-volume injection tests conducted through NETL's research are contributing towards increasing the knowledge of geologic reservoirs appropriate for CO_2 storage and the behavior of CO_2 in the subsurface. [16]

The Carbon Storage Program has focused on CCS technology development since its inception in 1997 with the goal of significantly improving the effectiveness and reducing the cost of implementing CCS technology. [14] [15] To accomplish this objective, the Carbon Storage Program focuses on developing technologies to utilize and store CO_2 from energy producers and other industries that rely on fossil-based energy sources without adversely affecting the supply of energy or hindering economic growth. The overall objective of the Carbon Storage Program is to develop and advance CCS technologies, both onshore and offshore, that will be significantly more effective, less costly, and ready for widespread commercial deployment in the 2025–2035 timeframe. The program has developed a diverse portfolio of applied research projects that includes industry cost-shared technology development projects, university research grants, collaborative work with other national laboratories, and research conducted in-house at NETL. The Technology Areas that comprise of the Carbon Storage Program are shown in Exhibit 1-1. The Core Storage R&D research component is a combination of three Technology Areas and is driven by technology need as determined by industry and other stakeholders, including regulators.

Exhibit 1-1. Carbon Storage Program structure



The Storage Infrastructure Technology Area comprises the Regional Carbon Sequestration Partnerships (RCSP) and other large- and small-volume field projects, as well as “fit-for-purpose” projects and the newly-initiated Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative (see Section 5.7.1.3); each initiative has its own focus on developing specific subsurface engineering approaches to address research needs critical for advancing CCS to commercial scale. It is in this Technology Area that various CCS technology options and their efficacy are being confirmed through field-based testing. These Core Storage R&D and Storage Infrastructure program components are being integrated to address technological and marketplace challenges. Overall, these two technology components sponsor applied research at laboratory and pilot scale, as well as support large-scale, large-volume injection field projects at pre-commercial scale to confirm system performance and economics. [17]

In all cases of R&D (applied R&D through field testing), CCS research benefits from drawing lessons from the history of other energy technologies and analog industries that were once considered risky and expensive early in their commercial development and are now commercially prominent. Building CCS into a key component for CO_2 management may require more than just technological feasibility; it may also require the development of both regulatory and incentive policies to support business models that can enable widespread adoption. [9] Furthermore, there is belief that a need exists for improved community awareness of the importance and value of CCS, and a necessity to enable CCS application to multiple industry types, each with distinctive emission footprints, markets, and costing structures. [8] Examples from analog industries that have faced similar technical hurdles but have eventually attained commercial success can provide insight into overcoming these types of challenges. For instance, Rai et al. (2010) [9] identified multiple non-technical factors that have facilitated commercial adoption of industries analogous to CO_2 storage. They analyzed the development of the U.S. nuclear-power industry, the U.S. sulfur dioxide-scrubber industry, and the global liquefied natural gas (LNG) industry to draw lessons for the CCS industry from these energy analogs that, like CCS today, were considered risky and expensive early in their commercial development. Through analyzing the development of the analogous industries to CCS, Rai et al. [9] arrived at three principal observations from which the analogous industries could achieve success:

- Government played a decisive role in the development of analog industries.
- Diffusion and penetration of these analog industries beyond early demonstration and niche projects is facilitated by the credibility of incentives for industry to invest in commercial-scale projects.
- The “learning curve” theory, where experience with technologies inevitably reduces costs, does not necessarily hold. Real learning is driven by more than just technical potential; it can also be influenced by the institutional environment present and any incentives towards cutting costs or boosting performance. The U.S. nuclear power industry and global LNG industry are noted examples where costs have increased with increasing capacity, contradicting the “learning curve” theory. Risky and capital-intensive technologies may be particularly vulnerable to wider-spread commercialization without accompanying reductions in cost.

Due to the importance of the Rai et al. findings, they are further explained in Appendix A: Overview of Rai et al., 2010. In addition to key points identified by Rai et al., others have noted [18] [19] that CCS-related research may also benefit from leveraging the data, lessons learned, and best practices from analogous industries with extensive operational histories.

1.2 Industrial Analogs for CO_2 Storage

The Intergovernmental Panel on Climate Change [4] and Rai et al. [9] identified several industrial analogs with experiences that are for the most part relevant to CO_2 storage. A few of the more prominent examples of industrial (engineered) analogs to CO_2 geological storage include 1) CO_2 EOR since 1972, 2) subsurface natural gas storage for over 100 years, and 3) injection and disposal of hazardous (like corrosive, ignitable, reactive, and toxic materials including oil-based paints, degreasing solvents, or chlorinated solvents) and non-hazardous wastes (like municipal and industrial wastewater) into deep confined rock formations, which has occurred in the United States since the 1930s and began being regulated by the Environmental Protection Agency (EPA) in the 1980s. [20] The worldwide experience of these industrial analogs demonstrates that the technology required to transport CO_2 to a storage site and inject it deep into the ground currently exists and can technically be applied. As mentioned in the sections above, these types of analogs provide the CCS community with insights, lessons learned, and best practices across all aspects of their respective domains. Additionally, studying analogs with extensive operational history enables evaluation of their temporal and spatial scales; given that many processes that must be assessed when predicting the performance of a CO_2 storage site occur over long timescales and can be only partially simulated in the laboratory or observed in relatively short-term demonstrations. Analogs though often have substantial differences and rarely provide fully comprehensive insight into every aspect of an emerging technology (CO_2 storage in this case); [19] emphasizing the need for continued R&D that 1) develops application-specific technological building blocks, 2) supports the creation of markets for which the technology under development can be deployed and prove, and 3) informs relevant legislative and regulatory actions. [9] [19] Some major differences between CO_2 storage and these industrial analogs discussed above include:

- CO_2 is injected during EOR operations with the intent to increase oil and gas production. The CO_2 is considered an asset as part of CO_2 EOR. Therefore, CO_2 EOR operators try to maximize oil and gas production and minimize the amount of CO_2 left in the reservoir. The goal of CO_2 storage is saline-bearing formation is to permanently store large volumes of anthropogenically-derived CO_2 in the subsurface.
- Natural gas is seasonally stored in (cyclically injected into, as well as withdrawn from) deep geologic formations. A base, or cushion gas, made up of natural gas is normally sustained in the subsurface at relatively constant volume to maintain adequate pressure and deliverability rates throughout withdrawal seasons. CO_2 storage operations are based on "one-way" injection of CO_2 with no intent on reproducing it from the subsurface.
- Hazardous and non-hazardous waste disposal via deep well injection is similar to CO_2 storage in terms of practice, how the wells are designed, and how operations are

regulated. However, supercritical CO_2 is highly buoyant compared to the displaced formational fluids and can migrate vertically in the subsurface and threaten intrusion into shallower formations, including drinking water sources. [20] Municipal wastewater operations, for example, are in fact susceptible to upward migration because of the wastewater's lower salinity, and thus greater buoyancy, than the native saline water in injection and confining zone strata [21], but are not nearly as buoyant as supercritical CO_2.

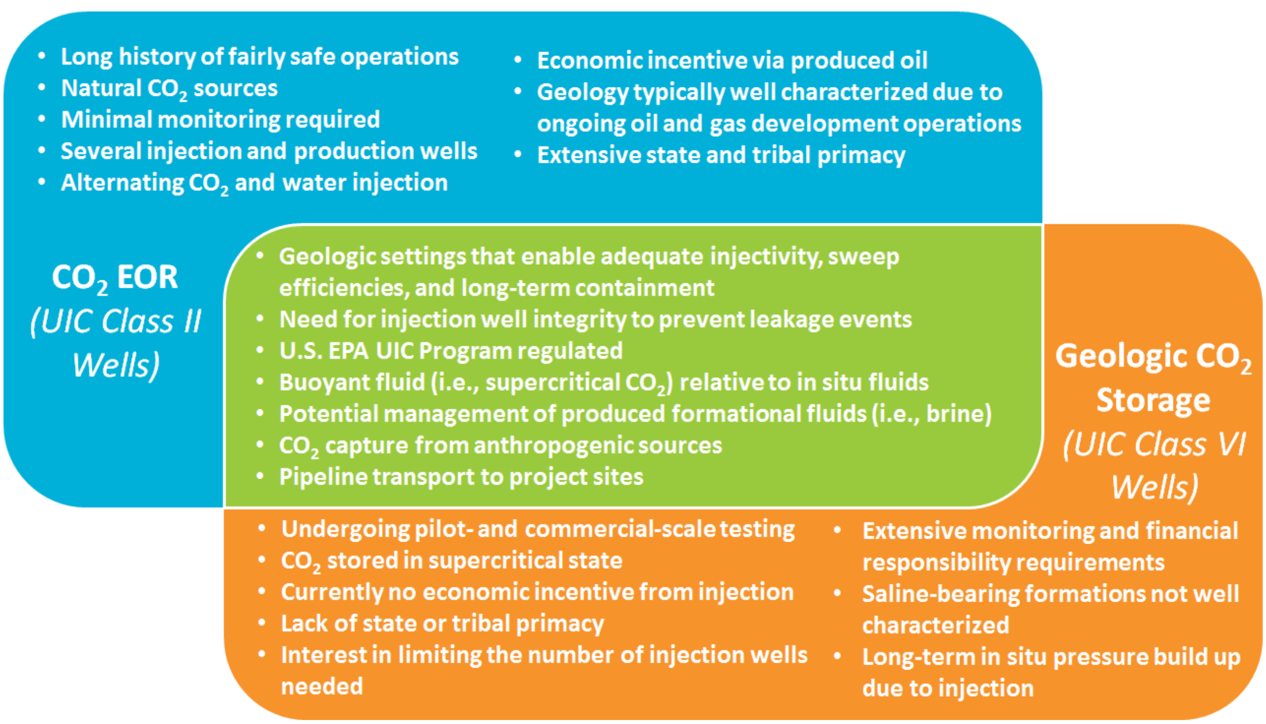
In addition to these differences, significant similarities between these analog industries and geologic CO_2 storage exist in terms of site selection and characterization, as well as operational procedures and the equipment used. [22]

This report focuses on CO_2 EOR and geologic CO_2 storage in saline-bearing formations; both individually and in relation to each other. CO_2 EOR was chosen as an analog to long-term geologic CO_2 storage because of the several commonalities between the two practices. For instance, both practice share the same risks related to the injection and storage of CO_2. Because of these shared risks, both practices utilize comparable similar well designs and similar equipment, including pumps, wells, pipelines, and monitoring equipment. Site operators for both CO_2 EOR operations and CO_2 storage operations wells must ensure that geologic reservoirs utilized at injection sites have the necessary capacity for storage, have sufficient injectivity to pump CO_2 into the formation at the desired rate, have sufficient geologic structure to prevent leakage, and that sites are safely constructed, operated, and maintained. Therefore, the extensive operational history of CO_2 EOR provides extensive knowledge and insight into lessons learned from which CO_2 storage stakeholders in industry, academia, and policy can benefit from.

The objectives of this report are multifold. First, the report is to provide a body of knowledge that specifically relates to historical and current subsurface CO_2 EOR operations, which may relate directly or indirectly to CO_2 geologic storage operations in saline-bearing reservoirs. The second objective is to document site selection methods, site characterization, and operating procedures that may also be relevant to future CO_2 storage operations. Best practices and lessons learned from analog industries can provide perspective from which future CO_2 storage R&D pursuits and field projects can benefit. Particularly, highlighting instances for how analogs to CO_2 storage overcome shared technical grand challenges (like those associated with identifying and ensuring injectivity, capacity, and containment throughout operations), and address regulatory requirements to achieve commercialization is a critical component of this objective. Third, this report is intended to document and learn from any reported leakage identified from CO_2 EOR operations. CO_2 leakage at EOR sites could consist of both leakage arising from the subsurface as well as fugitive emissions from surface equipment. Such leakage, if identified, would be considered directly relevant to CO_2 storage operations and is considered a major risk to wide-spread CCS deployment. [23] [24] [25] Only in a few isolated instances have there been documented leakage events associated with the long operational history of CO_2 EOR. But overall, experience has demonstrated that large volumes of gas can be stored safely underground and over long timeframes when the appropriate best-practices are implemented. Therefore, storing CO_2 in subsurface geologic formations at commercial-scales should also be feasible if comparable best practices are demonstrated. [26] However, there have been studies conducted over the years that have monitored ongoing CO_2 operations in attempts to identify surface and subsurface leakage of CO_2, as well as to better understand how CO_2 interacts within the subsurface and native fluids. An example is work conducted by the Gulf Coast Carbon Center at the Bureau of Economic Geology on the Scurry Area Canyon Reef Operators (SACROC) oil field in the Permian Basin (findings from this study are discussed in Section 6.4). Understanding the remedial actions that worked (as well as those that may have not been successful) in response to leakage events is also of importance. The fourth objective is to provide documentation of instances of public interaction concerning the development or operation of CO_2 EOR sites to provide insights into issues that might potentially arise during the development of a Class VI CO_2 storage well.

CO_2 EOR operations have been ongoing for over 40 years. Furthermore, CO_2 EOR is considered a means of CO_2 storage as it operates mostly as a closed system where all the CO_2 brought into the plant gate (i.e., purchased CO_2) will ultimately be stored in the reservoir since CO_2 produced with the oil and water is separated, recompressed, and injected back into the reservoir with minimal leakage. The amount lost through fugitive emissions or leakage from the subsurface into other formations or even into the atmosphere has generally been considered a negligible quantity. As mentioned in the preceding text, CO_2 EOR operations are very analogous to CO_2 storage operations in saline aquifers. This is due to the fact that the same fluid is being injected using similar types of injection wells and similar surface equipment. On the other hand, while several similarities exist, there are noticeable differences between the two practices also worth evaluating (Exhibit 1-2).

Exhibit 1-2. Venn diagram highlighting major differences and similarities between CO_2 EOR using Underground Injection Control (UIC) Class II wells and geologic CO_2 storage using Class VI wells



CO_2 EOR is a vital component of U.S. oil production. In 2002, CO_2 EOR accounted for approximately 187,000 barrels per day of crude oil (nearly three percent of U.S. crude oil production). [27] [28] By 2014, that number had increased to over 335,000 barrels per day from CO_2 EOR, making up nearly four percent of daily U.S. crude oil production. [27] [28] While CO_2 EOR has been a critical component to U.S. energy production, with robust policy and next-generation CO_2 EOR technology, it has exciting potential to expand as some projections indicate CO_2 EOR could produce upwards of 30 to 40 percent of all U.S. crude oil. [29] In addition to a robust policy and advanced technology, accessibility to higher volumes of affordable supplies of CO_2 will be needed to facilitate that growth. Large-scale capture and utilization of CO_2 from industrial facilities, chemical complexes, and electric power plants can be one route from which CO_2 EOR can achieve expanded economic potential. [28] In fact, large-scale integrated CCS projects in DOE's portfolio provide the first steps to broader commercial adoption. [17] [29]

The United States leads the world in both the number of CO_2 EOR projects and in the volume of CO_2 EOR oil production, in large part because of favorable geology. The Permian Basin covering West Texas and southeastern New Mexico has the bulk of the world's CO_2 EOR activity for two reasons: 1) reservoirs there are particularly amenable to CO_2 flooding and 2) large natural sources of high purity CO_2 are relatively close. However, a growing number of CO_2 EOR projects are being launched in other regions, based on the availability of low cost CO_2. [2] According to a 2014 article by Advanced Resources International, Inc. (ARI) in the *Oil & Gas Journal*, the CO_2 EOR industry injected 3.5 billion cubic feet per day (68 million metric tons [tonnes]/year [Mt/yr]) of a combination of natural and industrial CO_2 that produced 300,000 barrels per day of oil over 136 separate CO_2 EOR projects. ARI anticipates incremental oil production from CO_2 EOR operations to potentially double to 638,000 barrels per day by 2020 based on larger available volumes of CO_2 and several newly announced CO_2 EOR projects. [28]

Beyond its potential to augment U.S. oil production, CO_2 EOR has had intensive examination by industry, government, and environmental organizations for its potential for permanently storing CO_2. The reasoning is that CO_2 EOR provides the value of maximizing oil recovery, while at the same time offering a bridge to reducing CO_2 emissions from anthropogenic sources until CO_2 storage in saline-bearing formations becomes more cost effective. This is a prime example of how CO_2 EOR is such a strong analog for large-scale CCS. CO_2 EOR effectively reduces the cost of storing CO_2 by earning revenues for the CO_2 source via sales of CO_2 to EOR operators. Additionally, after years of experience with CO_2 floods, oil and gas operators are confident that the CO_2 left in the ground when oil production ends and the wells used are shut-in will stay permanently stored there, assuming the wells are properly plugged and abandoned.

In 2010, CO_2 EOR operations utilized 63 Mt of CO_2. About 20 percent of CO_2 used in EOR originated from anthropogenic sources, while the other 80 percent came from naturally-occurring underground sources. CO_2 utilized from natural sources (further described in Section 2.3.1 and Appendix B: Expanded Review of CO_2 Sources in the United States) does not contribute towards a net reduction in CO_2 emissions to the atmosphere. However, industrial CCS offers the potential to significantly alter that dynamic. [2] For instance, while CO_2 EOR has demonstrated significant success over nearly four decades, considerable potential remains for additional growth in production from this process. [28] This potential is further enhanced by the possibility of using captured anthropogenic CO_2 in fields that are good candidates for CO_2 EOR but located far from natural CO_2 reservoirs. As previously stated, CCS has been reviewed as one of the many emerging strategies for managing anthropogenically derived CO_2. [4] [13] [15] [17]

Injection of CO_2 captured from industrial or electric-generating sources into depleted oil reservoirs enables industry to extend oil production (recovering an extra 8 to 20 percent of the reservoirs original oil in place (OOIP) [1]) while emitting less CO_2 and offsetting the costs of CO_2 storage efforts. CO_2 EOR, therefore, has the potential to provide a critical near-term solution for reducing CO_2 emissions from anthropogenic sources. However, long-term storage of the injected CO_2 in subsurface formations must be safe, permanent, environmentally sustainable, and cost effective to be a viable option.

While several similarities and overlap between the CO_2 EOR and CO_2 storage in saline reservoirs exists, there are major differences, which include the standard injection approaches (multi-well configuration CO_2 and water flooding in CO_2 EOR coupled with CO_2 production and recycle versus one-way CO_2 injection in a least amount of wells possible for CO_2 storage), the varying levels of commercial application and experience of each practice, as well as the specific UIC well class and robustness of governing regulations. The similarities and differences between these two practices are further compared in the sections below. The critical findings from the experience of CO_2 EOR can be leveraged in the future, as well as be used to demonstrate that a level of understanding for how failures that resulted in any leakage events have occurred (and were remediated) in past CO_2 EOR operations has been achieved, so that CO_2 storage best practices can be developed and implemented.

2 Enhanced Oil Recovery Overview

Oil reservoirs have been developed for decades using primary, secondary, and tertiary recovery methods. When an oil field is brought into initial production (i.e., primary production), oil flows naturally towards producing wells and to the surface due to existing reservoir pressure. Primary recovery does not involve the injection of fluids into the reservoir. Most typical oil wells produce at their highest rate during the first few months of production. However, as oil is extracted over time, the volume and pressure in the formation is subsequently reduced, making it increasingly difficult to extract the remaining oil. Primary oil production typically recovers between six and 15 percent of the OOIP—a relatively small percentage overall (Exhibit 2-1). [1] This low recovery is an incentive for an operator to find additional ways to improve recovery and maintain continuous hydrocarbon flow by applying additional energy to the reservoir. [30] As reservoir pressure decreases following primary production, water can be injected into the reservoir (i.e., waterflooding), or possibly natural gas, to boost the pressures to displace remaining oil as part of a secondary recovery phase. [1] [2] Depending on the specific oil field, secondary recovery via waterflooding has demonstrated that an additional six to 30 percent of the OOIP can be recovered (Exhibit 2-1). [1] Secondary recovery helps to sustain higher production rates and extend the productive life of the reservoir. [30] Oil that is still left behind after waterflooding remains in the reservoir due to several potential possibilities: 1) either it is in portions of the reservoir that are uncontacted by the sweep of the waterflood or 2) it is part of the residual oil trapped by capillary forces that exist between oil, water, and the porous rock.

Exhibit 2-1. Oil recovery percentage range by production mechanism type and OOIP [1]

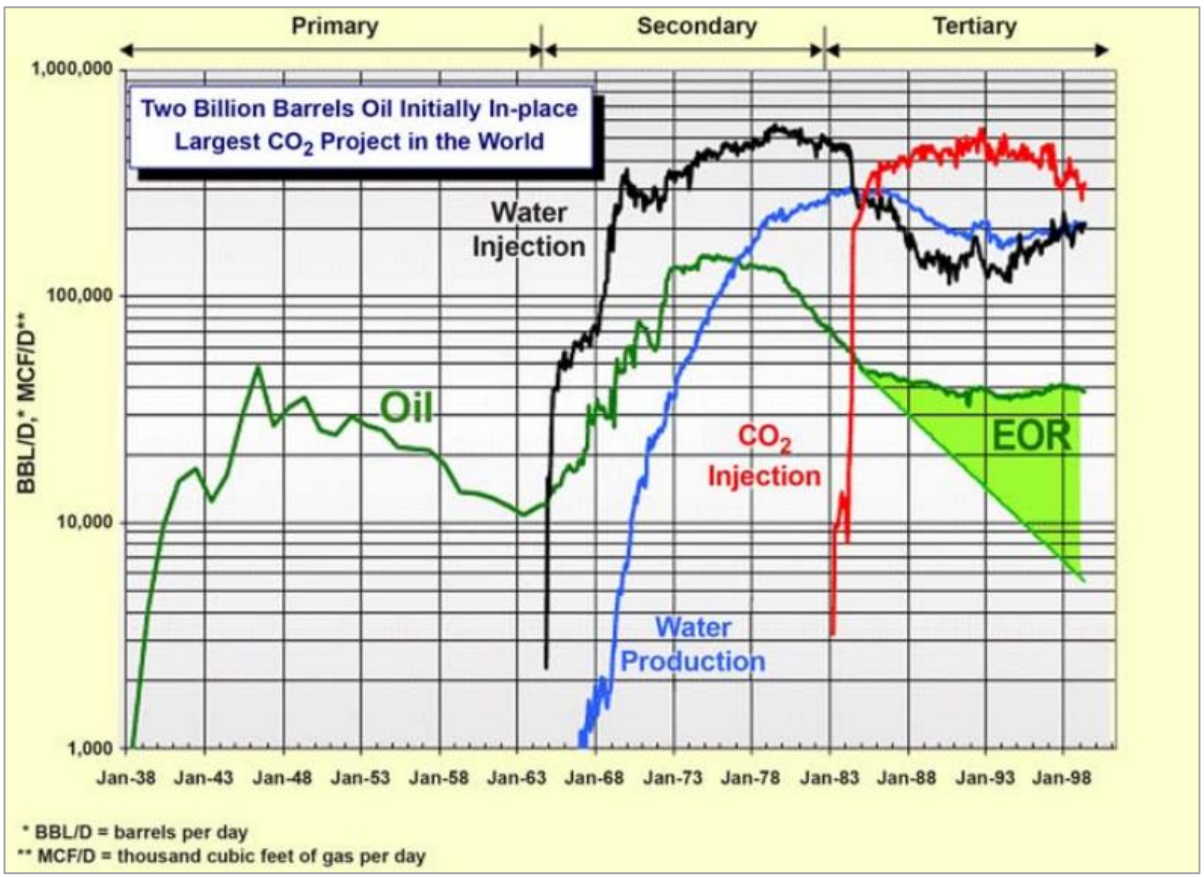
Production Mechanism	OOIP Recovery
Primary	6-15 percent
Secondary	6-30 percent
Tertiary	8-20 percent
Remaining	35-80 percent

The remaining oil in place following secondary recovery becomes a target for additional recovery using tertiary recovery (i.e., EOR) methods. Tertiary recovery is defined as oil production that is post-waterflood and driven by EOR processes like CO_2 injection (other processes include chemical, thermal, and displacement as described below). [2] A classification by Van Poolen and Associates, Inc. of EOR methods has the following three categories: [30] [31]

- Thermal methods that include steam stimulation, steam flood (including hot water injection), and in situ combustion
- Chemical methods that may include surfactant-polymer injection, polymer flooding, and caustic flooding
- Displacement methods that include the injection of hydrocarbon gas, CO_2, or inert gas under high pressure

The focus in this report going forward is specific to EOR approaches using CO_2. As mentioned, CO_2 EOR has two distinct advantages: 1) additional hydrocarbon recovery that promotes energy independence and security, as well as 2) the ancillary benefit of CO_2 storage (which is of greater importance if the CO_2 is derived from anthropogenic sources). [2] [30] As mentioned, CO_2 EOR is one of several tertiary production approaches that can be utilized to recover a larger percentage of the oil in place once both primary and secondary recovery have ended (Exhibit 2-2). [32] The production plot in Exhibit 2-2 illustrates how an oil reservoir can respond to CO_2 injection following primary and secondary recovery. The specific example in Exhibit 2-2 depicts oil and water production, and water and CO_2 injection, over a 60-year period for Shell Oil's Denver Unit in the Wasson Field from the San Andres formation in West Texas. Starting in 1983 when CO_2 injection began, the plot demonstrates how CO_2 EOR generates additional incremental oil. [2]

Exhibit 2-2. Oil production versus time for primary, secondary (waterflood), and tertiary (CO_2 EOR) oil production periods for the Denver Unit of the Wasson Field in West Texas [33]

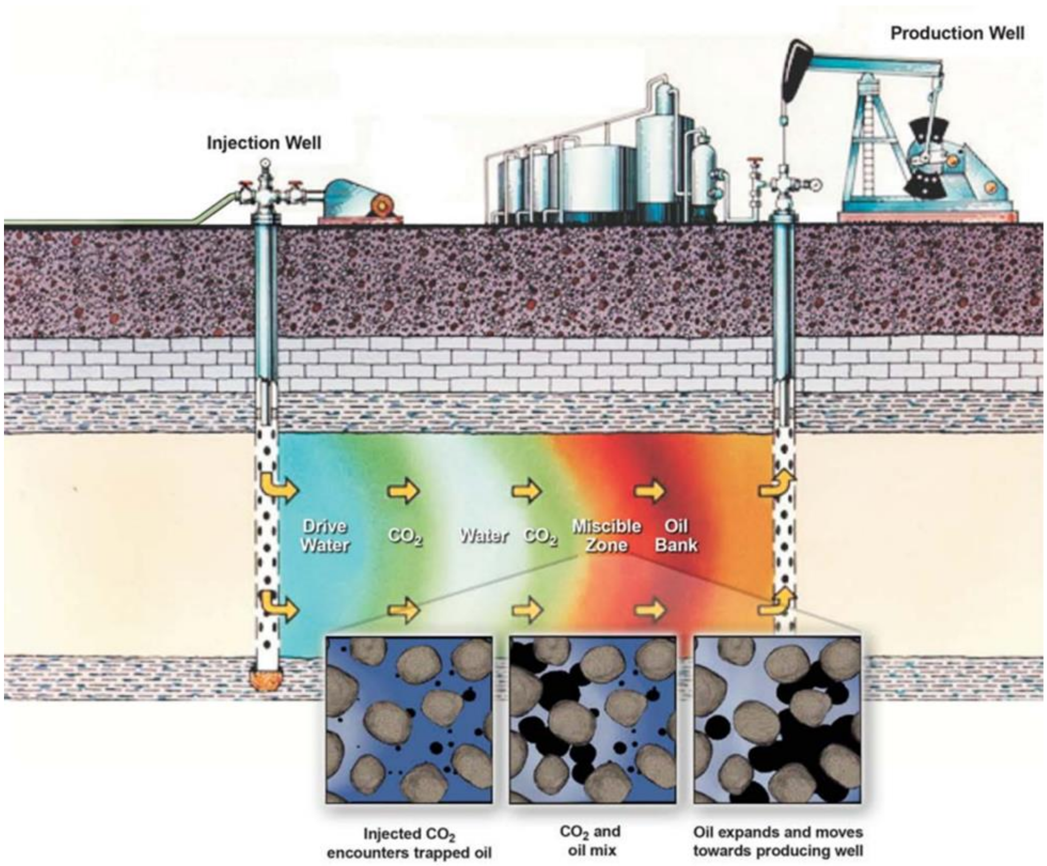


Note: The incremental oil production associated with CO_2 EOR operations is represented by the green area under the curve at right.

2.1 How CO_2 EOR Works

The physical elements of typical CO_2 EOR operations, highlighted in Exhibit 2-3, will help illustrate how the process works. Injected CO_2 (typically called a CO_2 flooding process) enters the oil reservoir via injection wells and moves through pores, contacting residual droplets of crude oil left behind following primary and secondary recovery techniques. There are two types of common CO_2 EOR approaches—miscible and immiscible flooding—with miscible flooding being the most effective and common. For a common miscible flood, CO_2 injected into the oil reservoir is in a supercritical state due to elevated reservoir temperatures and pressures at depth. [30] This supercritical CO_2 mixes with the oil to form a low viscosity fluid with very low surface tension that can be more easily displaced. [1] Miscibility can be defined as the physical condition between two or more fluids that enable them to mix in all proportions without the existence of an interface. [1] Additionally, the low-viscosity of CO_2 provides the capability of invading portions of the reservoir not previously swept by waterflooding. The miscible mixture can then move throughout the reservoir, contacting and freeing more oil as it flows towards a production well (Exhibit 2-3). Depending on the reservoir's specific geological properties and conditions, oil recovery estimates for miscible CO_2 EOR flooding as the tertiary recovery process can vary, but typical estimates are shown in Exhibit 2-1 above. [1]

Exhibit 2-3. Depiction of CO_2 EOR tertiary production using a water and alternating gas injection approach [2]



Under an immiscible flood, the injected CO_2 does not entirely mix with the oil. Immiscible conditions occur when the reservoir pressure is below what is called the minimum miscibility pressure (MMP).[a] The main purpose of the immiscible flood is to provide energy or drive in the

[a] MMP is the pressure at constant temperature and conditions at which the crude oil and CO_2 become miscible at first- or multiple-contact. Correlations between MMP and reservoir temperature for CO_2 flooding have been made by Mungan and Stalkup. [112] [285]

subsurface by increasing the reservoir pressure. [34] Other desirable effects include swelling of the oil and reduction of oil viscosity. Immiscible flooding does not produce as much oil as miscible flooding; however, there are certain applications and reservoirs wherein immiscible flooding is well-suited, for instance, heavy oil applications. [35]

CO_2 EOR production is typically developed in phases across an oil field, with the injection and production wells organized in a specific pattern. [36] The number and pattern of production and injection wells can vary by oil field, as well as change over the life of the production operation. The needed quantity for both injection and production wells (and monitoring wells) for a given field can be attained through drilling new wells and/or recompleting older wells during operations. [30] The oilfield facility requirements for CO_2 EOR are like those required for a waterflood except for the additional facilities needed for CO_2 separation, as well as injection. During the tertiary recovery process, oil, water, and CO_2 (possibly with natural gas) are produced at the surface and managed appropriately by one of several surface facilities. Any produced CO_2 is separated from the other fluids, recompressed, and re-injected (along with additional volumes of newly-purchased CO_2 brought onsite). In general, surface facilities at CO_2 EOR sites typically include the following basic elements: [30] [37]

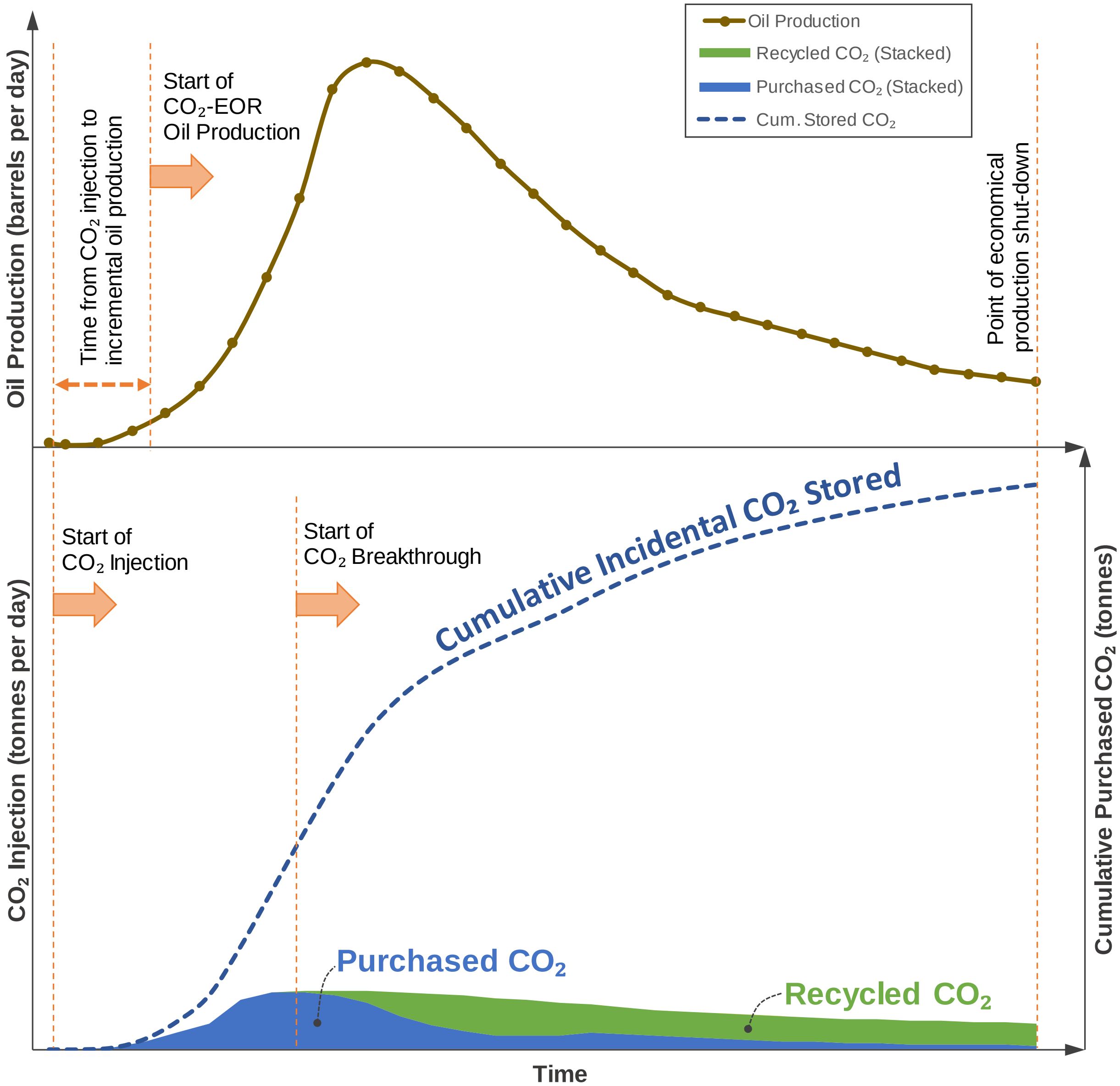
- Separation facilities to extract CO_2 (and natural gas) from the produced fluid. Increasing quantities of CO_2 are expected at production wells once breakthrough is achieved. In some situations, separated produced water is treated and re-injected, often alternating with CO_2 injection, to improve sweep efficiency (i.e., water alternating gas [WAG] described in Section 4.2)
- Processing to purify recycled CO_2 to specification after separation from the produced fluids. Dehydration before compression is another critical step
- Compression of the CO_2 required to raise its pressure for re-injection
- Distribution systems to deliver purchased and recycled CO_2 to injections wells. CO_2 distributions systems are similar to gathering systems used for natural gas

Cumulative injected CO_2 volumes at CO_2 EOR operations vary from site to site, but typically range between 15 and 30 percent of the hydrocarbon pore volume (HCPV) of the reservoir. [2] Historically, the motivation for CO_2 EOR site operators has been to minimize the quantity of CO_2 injected per incremental barrel of oil recovered (i.e., CO_2 utilization factor), [2] especially due to the costs associated with purchasing and injecting CO_2. [37] CO_2 is considered a valuable commodity by the CO_2 EOR industry, because of its ability to stimulate oil production from depleted reservoirs, and because of the limited volumes of available CO_2 in the United States (particularly from naturally-occurring sites); hence the efforts at large-scale commercial floods to separate, compress, and re-inject CO_2 numerous times to maximize value of this asset. [36] [37] However, if carbon storage becomes an added driver for CO_2 EOR initiatives, the returns from CO_2 storage could begin to favor injecting larger volumes of CO_2 per barrel of oil recovered. [2]

Typical project life cycles for individual CO_2 EOR projects are difficult to describe holistically since very few have run through the entire cycle. For example, there are CO_2 EOR projects that started with tertiary CO_2 flooding in the early 1980s and are still purchasing CO_2 today, despite forecasting that they would have likely already committed to total CO_2 recycle. [37] Experience indicates that the volume of CO_2 needed for a CO_2 EOR project changes over a field's life. Additionally, the fraction of different fluids—oil, gas, water, and CO_2—in the production stream will vary over the life of a CO_2 EOR project as well. [36] The facilities on the surface used to manage these extracted fluids need to be effectively planned with a goal of maintaining field performance, as well as profitability. A general workflow has been presented by ARI (2011) for the use of CO_2 in a reservoir. It is described in the following bullets and in Exhibit 2-4: [37]

- As tertiary recovery begins, the reservoir is flushed with substantial amounts of CO_2. There can be a large gap before the effect of the injected CO_2 on oil production is realized; in many cases, a gap of 18 to 24 months from initial injection of CO_2 until oil production begins is a rule of thumb.
- The objective of the flood is to inject as much CO_2 as economically viable to maximize production. Therefore, as tertiary recovery progresses, more CO_2 is added to the reservoir.
- After a period of CO_2 injection (length dependent on site-specific conditions), the produced oil will contain CO_2 as well. The CO_2 within the produced oil is separated and re-injected back into the oil field. The need for the field to purchase new CO_2 is gradually reduced over time. As a result, a greater percentage of the CO_2 injected is from production, separation, and recycling versus newly-purchased CO_2.
- Tertiary recovery with CO_2 should likely continue until a given field's production falls to a level where the operating costs equal or drop below the marginal revenues, and the oil production is therefore no longer a profitable venture. As in any type of production, the economic feasibility of a CO_2 flood is strongly correlated to the oil price. [38]

Exhibit 2-4. Concept of the relationship of recycled CO_2 being used compared to newly purchased CO_2 during the course of a CO_2 EOR operation, and relative incidental CO_2 storage [37] [38] [39]



As this cycle (shown in Exhibit 2-4) is continually repeated, CO_2 will be progressively retained in the reservoir so that eventually, all the purchased CO_2 would reside within the subsurface. The mass of CO_2 purchased, net any venting during EOR activity, is essentially stored in the reservoir by a combination of capillary, solution, and physical trapping mechanisms. [36] Venting to the atmosphere is a rare event, quantifiable, and constitutes an insignificant fraction of the injected CO_2. For each cycle, the "stored" portion of CO_2 can be a considerably substantial portion of the total CO_2 injected (generally considered to be 30 to 40 percent but will likely vary based on the geologic properties of the reservoir in question). Overall, this CO_2 that remains in the subsurface as part of the oil production cycle is a form of geologic storage, as the CO_2 will be contained indefinitely within the reservoir. This is often referred to as incidental storage. [39] Additional purchase of CO_2 is necessary to replace the "stored" CO_2 to maintain the total mass of CO_2 for injection for a given CO_2 EOR flood.

CO_2 EOR technologies have been demonstrated to be profitable in commercial-scale applications for over 40 years, [36] [37] demonstrating the maturity of the technology and processes involved. The following sections provide an overview of the history of U.S. EOR industry, providing insight into its start in the 1970s to its prominence today.

2.2 THE HISTORY OF CO_2 EOR

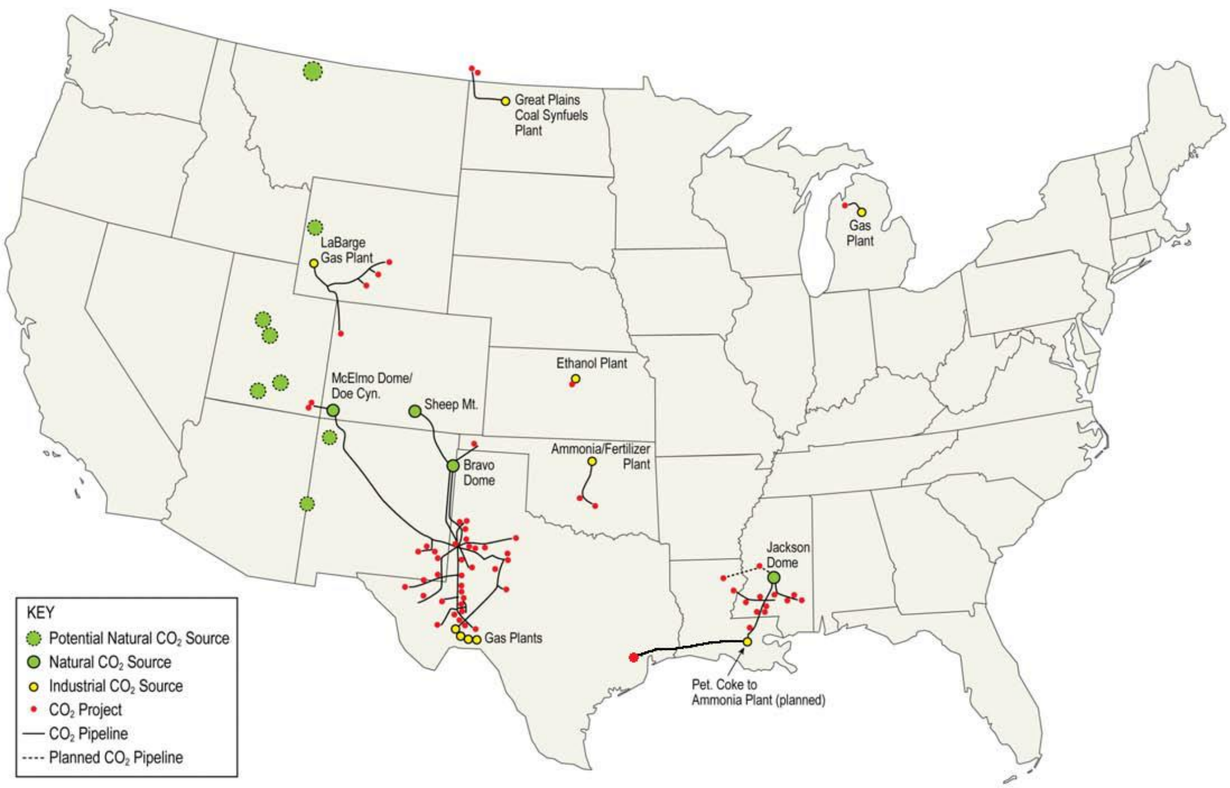
The oil industry in the United States has been injecting CO_2 for EOR for approximately 45 years. The first patent associated with the CO_2 EOR technology concept was granted to Whorton, Brownscombe, and Dyes of the Atlantic Refining Company in 1952. [1] [40] In 1964, a field test was conducted at the Mead Strawn Field in Texas, which involved the injection of a large slug of CO_2 into a Pennsylvanian sandstone equating to roughly 25 percent of the HCPV. The CO_2 injection was followed by carbonated water injection. Results were encouraging and showed that 53 to 82 percent more oil was produced by the CO_2 flood than was produced by water in the best areas of the waterflood. [41] Following this success, more laboratory and pilot testing of the CO_2 EOR concept followed.

In January 1972, the first commercial CO_2 EOR injection project was initiated at the SACROC Unit of the Kelly-Snyder Field in Scurry County, West Texas. [36] Initially, 220 million cubic feet per day of CO_2 was supplied to SACROC from the Val Verde Gas Plants in west Texas, where the CO_2 is removed from gas generated during ammonia production and shipped via the Canyon Reef Carriers System for injection at 2,350 pounds per square inch gauge (psig). [1] [42] Numerous field developments and facility expansions have occurred at the site since the 1970s, resulting in a field gas-handling capacity of more than 0.6 billion cubic feet of CO_2 per day. [1] As of 2014, the SACROC field produced 28,300 barrels of enhanced oil production per day and remains the world's largest miscible flooding project. [43]

The development and success at SACROC led to an increase of CO_2 EOR projects across the United States, particularly in West Texas and eastern New Mexico. A viable CO_2 EOR market was established in the Permian Basin when oil companies including Shell and Gulf transported CO_2 via pipeline to oil reservoirs for EOR. Projects involving CO_2 EOR in the Wasson Field (Yoakum and Gaines Counties in Texas) are examples of early Permian Basin projects. Current Permian Basin CO_2 supplies are now originating from naturally-occurring sources include Bravo Dome in New Mexico and McElmo Dome and Sheep Mountain in Colorado. [44] Additionally, anthropogenic CO_2 sources including gas plants in southwestern Texas also supply the region. [28] The Permian Basin has since grown to more than 60 CO_2 EOR projects producing 65 million barrels of oil per year. For CO_2 EOR, it is the dominant basin in worldwide production, with two thirds of the world's EOR oil being produced from within the basin. [43] From a CO_2 utilization perspective, a 2013 article by Hill et al. indicates that approximately 600 Mt of purchased CO_2 have been utilized in the Permian Basin since the early 1970s (more on a cumulative basis if CO_2 recycle is considered)—the rough equivalent of 30 years' worth of CO_2 from a half dozen medium-sized coal-fired power plants. [36]

In the United States, CO_2 EOR has grown beyond the Permian Basin to other regions, like Wyoming, Texas, Louisiana, Mississippi, and southeast New Mexico. Beyond that, the Mid-continent (Oklahoma and Kansas mostly) and Michigan also have CO_2 EOR operations (Exhibit 2-5). [36] Additionally, pipeline infrastructure dedicated to moving CO_2 from natural and anthropogenic sources to EOR projects has grown to over 4,000 miles in length. [36]

Exhibit 2-5. Location of current CO_2 EOR projects and pipeline infrastructure pertaining to the U.S. Lower 48 [2]

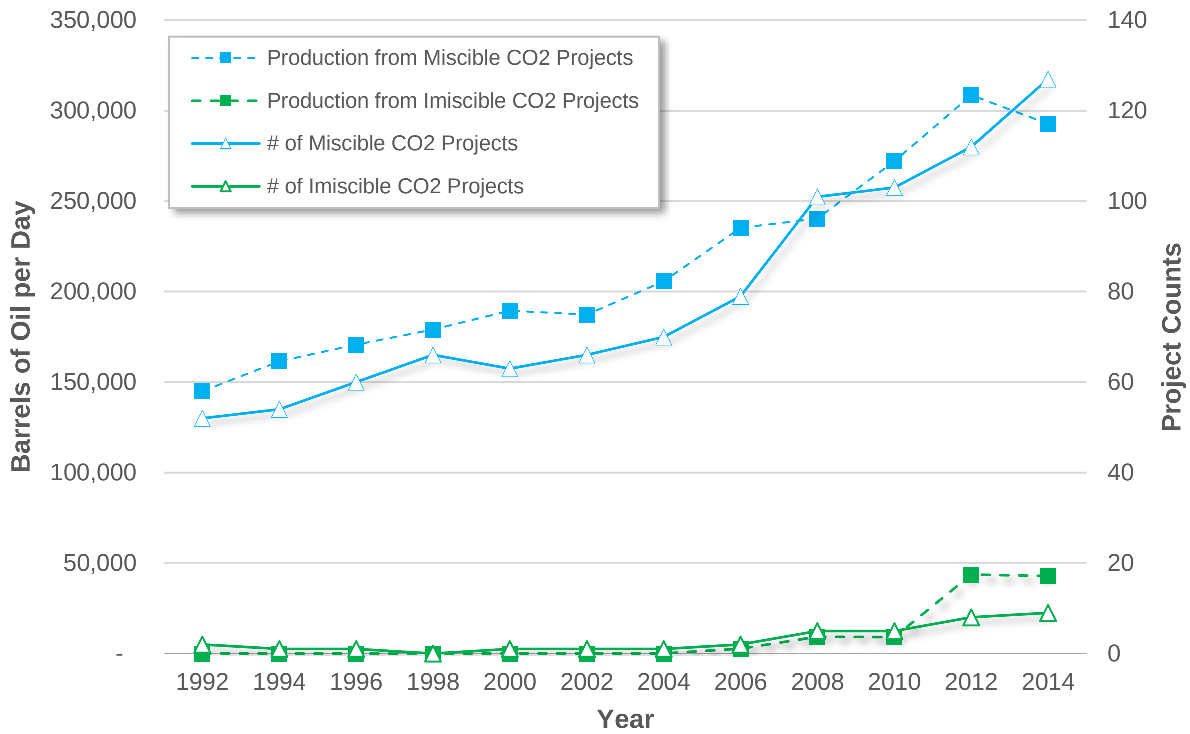


Note: Image from the NETL-developed document titled *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution*. The image may not be current with more recent CO_2 pipeline infrastructure development or CO_2 EOR project starts.

Since 1992, the *Oil & Gas Journal* has conducted a biennial survey of EOR operations. Exhibit 2-6 shows the number of U.S. EOR projects with their daily production from the 2014 *Oil & Gas Journal* EOR survey (which is the latest available version).[b] The data show that since 1992, the total number of CO_2 EOR projects has increased by 117 percent, and the total production from CO_2 EOR has increased by 131 percent.

[b] The 2014 release of the Worldwide EOR Survey featured corrections to the project tables. Therefore, the time-series project and production counts compiled to generate Exhibit 2-6 required data compilation from both the 2014 update and the original 2014 survey release. [43]

Exhibit 2-6. Number of active U.S. CO_2 EOR projects from 1992 - 2014 by year and production type, including incremental oil production volumes per day [43]



Data suggests that the majority of CO_2 EOR production has been in and is still being produced from the Permian Basin. [45] However, Melzer Consulting has suggested that the lack of a sufficient supply of CO_2 to sustain increasing project growth in the basin, and potentially other parts of the nation, could affect sustained CO_2 EOR growth moving forward. [46] After nearly a decade in which CO_2 supplies in the Permian Basin exceeded the demand for CO_2 EOR projects, there has been a shortfall of CO_2 supply since 2004. [47] Furthermore, recent estimates of future CO_2 demand suggest that considerable volumes of CO_2 will be required to meet potential next generation EOR. The supply of CO_2 needed to undertake or expand EOR in the United States could be supplemented with new volumes of anthropogenic CO_2 as a way to satisfy demand potential. [36]

2.3 U.S. CO_2 EOR Markets — Sources and Sinks of CO_2

Although the large Permian Basin reservoirs were readily recognized as ideal candidates for miscible flooding through CO_2 injection, it was the availability of a low-cost source of CO_2 (i.e., Val Verde Gas Plants) that drove the Permian Basin's EOR boom in the 1970s and 1980s. The technical success of SACROC, coupled with the high oil prices of the late 1970s and early 1980s, led to the construction of three major CO_2 pipelines connecting the Permian Basin oil fields with natural underground CO_2 sources (i.e., Bravo Dome, New Mexico, McElmo Dome, Colorado, and Sheep Mountain, Colorado). [2]

Even with CO_2 sources just a few hundred miles away, the cost of delivering and injecting the CO_2 is significant. NETL reports that industry has spent over $1 billion on 2,200 miles of CO_2 transmission and distribution pipeline infrastructure in support of CO_2 flooding in the Permian Basin. Typically, it costs $0.25–0.75 per thousand cubic feet to transport CO_2 to West Texas fields from the natural sources to the north. With a substantial CO_2 pipeline and distribution infrastructure in place, Permian Basin operators have spread the costs among several large fields, and the infrastructure in these fields in turn has helped reduce the cost of delivered CO_2 to smaller fields in the basin. Yet, as mentioned, there is still substantial demand (upwards of 500 million cubic feet per day; 25,974 tonnes per day) for CO_2 in the Permian Basin alone for potential CO_2 EOR projects. [2] Additional natural CO_2 resource have been discovered in the Arizona-New Mexico region and may be developed if the economics become favorable.

In the Gulf Coast Region, Denbury Resources (Denbury) has made substantial progress developing a similar CO_2 pipeline infrastructure system in Mississippi, Louisiana, and southeastern Texas. Denbury owns a large natural CO_2 resource at Jackson Dome, Mississippi, which it describes as the largest CO_2 resource east of the Mississippi River. Jackson Dome already feeds CO_2 to EOR projects Denbury operates in Mississippi and Louisiana. In 2010, Denbury completed construction of the 320-mile long Green Pipeline (originating near Donaldsonville, Louisiana), which delivers CO_2 for injection at the Hastings Field in Texas (south of Houston) and was designed to collect and deliver CO_2 from both natural and anthropogenic sources. [36] [48] The company is also reported to be in negotiations with industrial plants along the pipeline route, including four proposed gasification plants fed by coal or petroleum coke, to secure additional supplies of captured anthropogenic CO_2 for EOR projects in all three states within the region. Another Denbury pipeline, the Greencore Pipeline, was recently completed in 2012 (initial section of the pipeline). This initial section of the Greencore Pipeline is 232-miles in length and connects the ConocoPhillips-operated Lost Cabin natural gas separation plant in Wyoming through the Powder River Basin to Montana’s Bell Creek Field. The first CO_2 deliveries from this pipeline occurred in 2013. In 2014, Denbury completed construction of an interconnect between the Greencore Pipeline and an existing third-party CO_2 pipeline in Wyoming, which enables CO_2 transport from the LaBarge Field in Wyoming to the Bell Creek Field in Montana, [49] as well as plans for an extension to several recently acquired oil fields in East Central Montana and Western North Dakota known collectively as the Cedar Creek Anticline. [50]

These examples provide some insight into a few of the efforts made to connect viable CO_2 sources to oil field markets for EOR. A safe, reliable, regionally extensive network of CO_2 pipelines is already in place across a substantial portion of the United States (and parts of Canada as well). This system can provide an essential building block for linking the capture of CO_2 from anthropogenic CO_2 sources to productive use in oil fields (with CO_2 EOR) and has the potential utility for the application of CO_2 storage in saline formations. The following section provides a deeper evaluation on the types and locations of CO_2 sources in the United States, as well as a review of the most promising (and currently thriving) CO_2 EOR markets.

2.3.1 Sources of CO_2

Previous sections of this report have referenced both anthropogenic and naturally-occurring sources of CO_2. For the purposes of CO_2 EOR, both have been utilized. To avoid ambiguity, the terms are defined as follows:

- **Naturally-occurring (geologic) CO_2:** Molecules of CO_2 that were created within the Earth's crust. These molecules existed as CO_2 in situ and became trapped underground. As an example, New Mexico's Bravo Dome, which has been a major source of CO_2 for EOR since the 1980s, was created naturally from volcanic activity in the region. The volcanic activity produced gas, including CO_2, that migrated into sandstone reservoirs through fractures in the underlying bedrock. The sandstone is bounded by impermeable layers and is shaped in a dome-like structure; therefore, it collects the buoyant CO_2. [51] The fact that naturally-occurring deposits of CO_2, like Bravo Dome, have remained in the subsurface over extremely long durations provides confidence that potential commercial-scale geologic CO_2 storage is technically feasible.
- **Anthropogenic CO_2:** Molecules of CO_2 that were created by a human-caused chemical process. In the strictest terms, each human produces anthropogenic CO_2 through the process of aerobic respiration. Cars and trucks produce anthropogenic CO_2 through the combustion of gasoline. Industrial point sources of CO_2, such as coal-fired power plants, create CO_2 through the combustion of coal. These CO_2 molecules would not exist without human activity oxidizing carbon. These CO_2 exhaust streams are far from pure CO_2, containing a host of pollutants including nitrous oxides, sulfur compounds, and particulates. Other industrial point sources produce CO_2 through chemical processes other than oxidation/combustion. For instance, ethanol production plants produce a nearly pure stream of CO_2 through fermentation. Petroleum refineries, cement, and fertilizer plants also produce nearly pure streams of CO_2 through other chemical processes. Industrial point sources provide unique opportunities to capture and separate CO_2 from their respective processes and then utilize the CO_2 for multiple types of end uses, including CO_2 EOR, geologic storage, or even as a feedstock in cement, chemical, and fuel creation. [17]

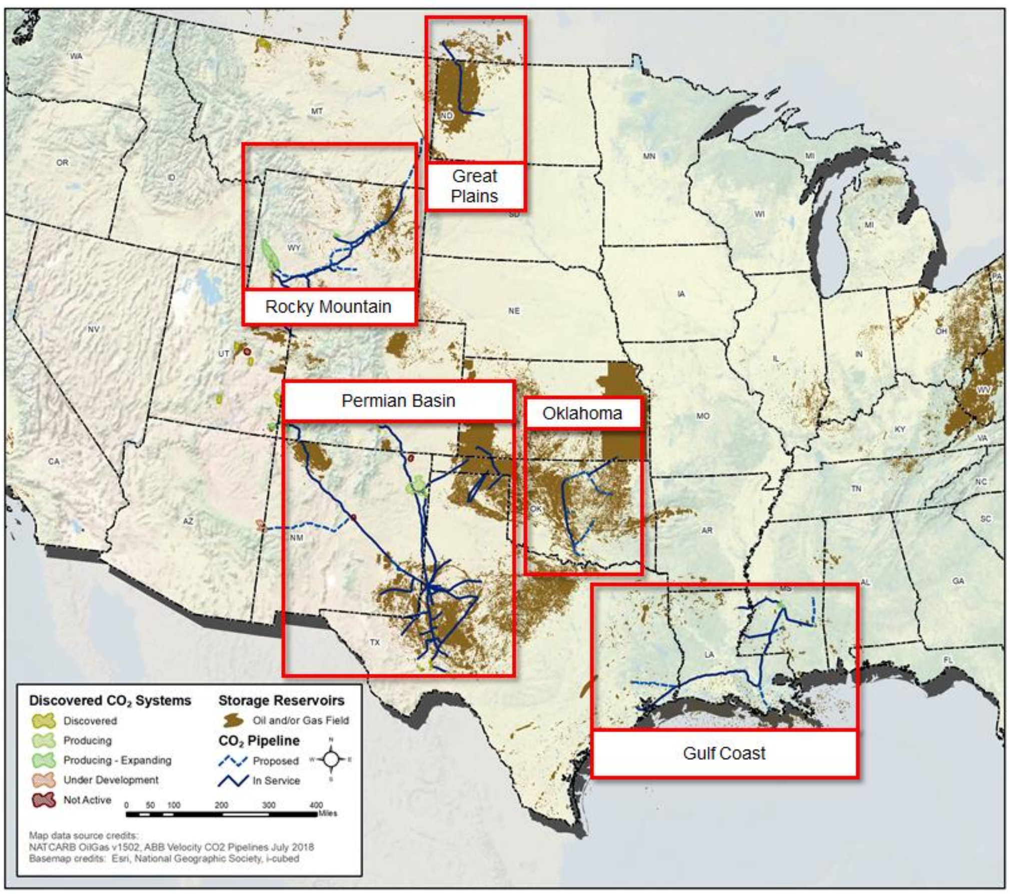
The location and size (i.e., CO_2 emission rate) of anthropogenic CO_2 sources is well understood and documented. [14] [52] [53] [54] [55] However, the extent of remaining naturally-occurring CO_2 is not as well understood. In fact, most naturally-occurring CO_2 deposits discovered to date have been the by-product of hydrocarbon exploration. Industry has not embarked on a serious undertaking for CO_2 exploration. In other words, naturally-occurring CO_2 has been found accidentally. Appendix B: Expanded Review of CO_2 Sources in the United States contains more information pertaining to the location and size of anthropogenic CO_2 sources in the United States, as well as further insight into the naturally-occurring discovered and potential yet undiscovered CO_2 deposits.

2.3.2 CO_2 Sinks — EOR Fields

EOR currently exists in five geographically-isolated markets in the U.S. These markets, as illustrated in Exhibit 2-7, are isolated because of infrastructure. CO_2 pipelines in Exhibit 2-7 connect naturally-occurring and anthropogenic sources of CO_2 to oil fields (sinks). Much like oil field services, CO_2 is sold to EOR operators at a price that typically varies with the price of oil. Cheaper oil results in less need for EOR production and consequently lower demand for CO_2. Likewise, higher oil prices drive the need for EOR production and CO_2 sells at more of a premium. Generally, CO_2 sells for about one to two percent of the price of a barrel of oil per thousand cubic foot of gas. When oil is selling for $50 per barrel, CO_2 typically sells for about $1 per thousand cubic foot, or about $19 per tonne.

Two of the larger CO_2 EOR markets highlighted in Exhibit 2-7, the Permian Basin and Rocky Mountain region, are discussed in more detail in the following subsections. These subsections provide perspective of the existing pipeline infrastructure and CO_2 sources relative to oil fields in each region.

Exhibit 2-7. Major EOR markets of the U.S. Lower 48 plotted with different CO_2 source types

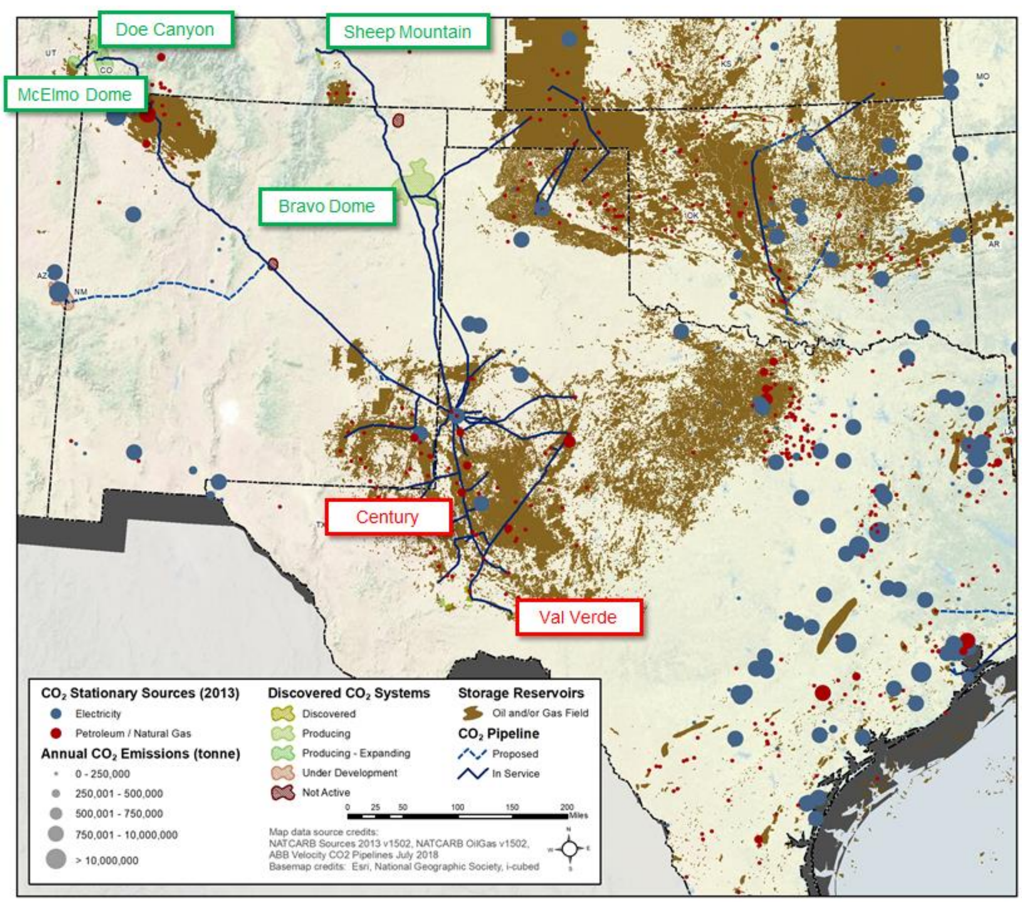


2.3.3 The Permian Basin EOR Market

The Permian Basin EOR Market (PBEM), located in West Texas (Texas Railroad Districts 8 and 8A) and southeastern New Mexico, remains one of the largest oil producing regions of the world. The basin contains numerous large, deep, light oil fields and reservoirs attractive for CO_2 EOR. The conventional oil fields are mature and, except for those with active CO_2 EOR operations, are in steep decline. In 2009, this area ranked first for U.S. oil production with 289 million barrels of oil production (790 thousand barrels per day). In 2016, the production expanded by nearly 2,000 barrels per day (not all associated with CO_2 EOR). To date, the Permian Basin has produced 32 billion barrels of oil with 4.8 billion barrels of remaining proved reserves. [56]

Exhibit 2-8 provides an overview of the PBEM, where fields in West Texas and southeastern New Mexico are undergoing CO_2 flooding for EOR. Purchased CO_2 is piped to the Permian Basin from McElmo Dome, Sheep Mountain, Doe Canyon, and Bravo Dome fields in New Mexico and southern Colorado. A small amount of CO_2 is captured from the Val Verde Gas Plants in Terrell County, Texas, as well as the Century Gas Plant in Pecos County, Texas. [57] The PBEM is not currently interconnected with other CO_2 EOR market systems. However, new pipeline construction could be considered to connect several of the regional CO_2 sources within the Permian Basin, as well as to other anthropogenic sources in the Mid-Continent area; for instance, like a connection between the existing Koch Fertilizer plant in Oklahoma.

Exhibit 2-8. The Permian Basin and Oklahoma EOR markets



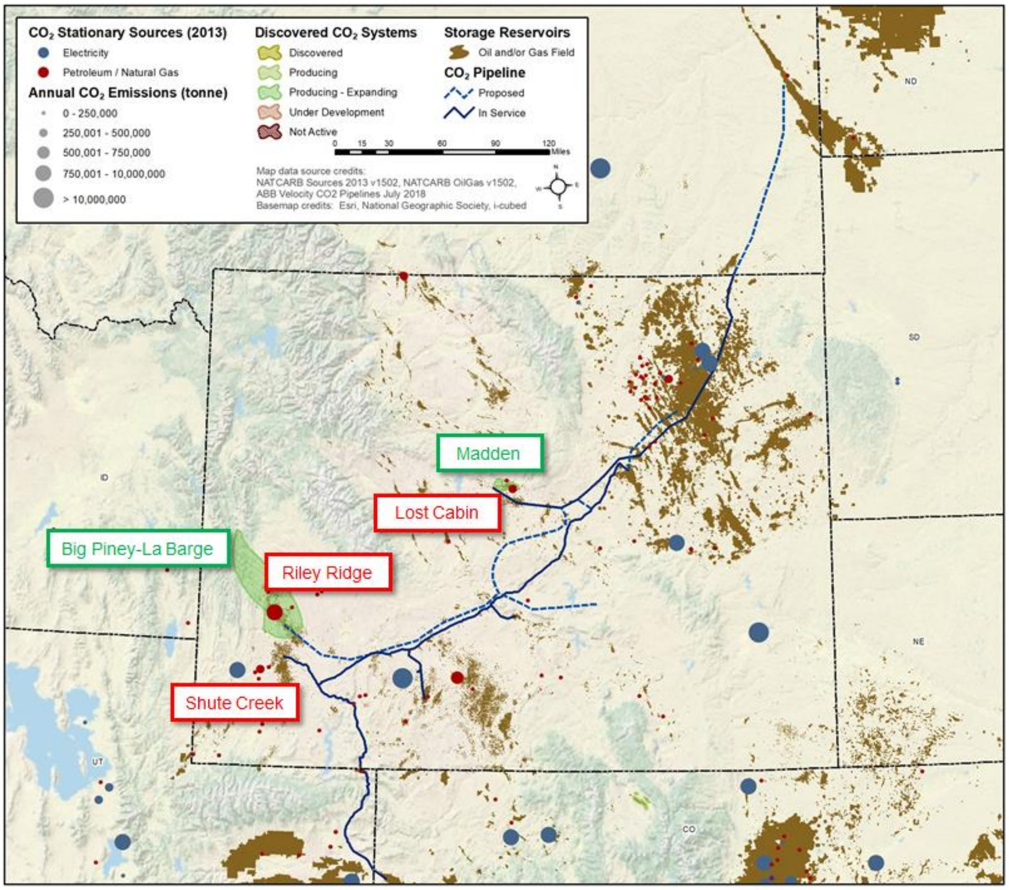
2.3.4 The Rocky Mountain EOR Market

CO_2 for EOR is used at Rangely field in Colorado, as well as Salt Creek, Bairoil, Patrick Draw, and Beaver Creek in Wyoming. This CO_2 is largely sourced from the Big Piney-LaBarge (BPLB) field in the Green River Basin, but also from the Madden field in the Wind River Basin. The BPLB serves as the largest source of CO_2 used for EOR at oil and gas fields across the northern Rocky Mountains. The field produces natural gas (21 percent average) and CO_2 (65 percent average) from the Mississippian-age Madison Limestone. [58] The mixed gas stream produced from BPLB is ultimately sent to the Shute Creek Treating Facility in Lincoln County, Wyoming, where the CO_2 is separated. [59] The Madden field is a conventional natural gas field that produces from multiple reservoir units ranging in depth from 5,000 to 25,000 feet. According to Elk Petroleum, the Madden field has produced over 2.42 trillion cubic feet (Tcf) of natural gas. [60] The Lost Cabin Gas Plant (described below) located in Fremont County, Wyoming, separates and captures CO_2 from the natural gas produced from the Madden field. [61]

BPLB is large, comprising 650,000 acres in south Sublette County and northeast Lincoln County, 25 miles north of Kemmerer, Wyoming, in the west-central part of the Green River Basin. The field is located on a large structural high, known as the LaBarge Platform. Drilling activity in the Big Piney gas field began in 1952 and was successful with the market provided by a Pacific Northwest natural gas pipeline, running from the San Juan basin in southern Colorado to the state of Washington. [62] Today, the BPLB field consisting of the Tiptop, Dry Piney, Hogsback, LaBarge, and Big Piney oil and gas fields, produces to the Shute Creek gas plant with a natural gas capacity of 600 million cubic feet per day.

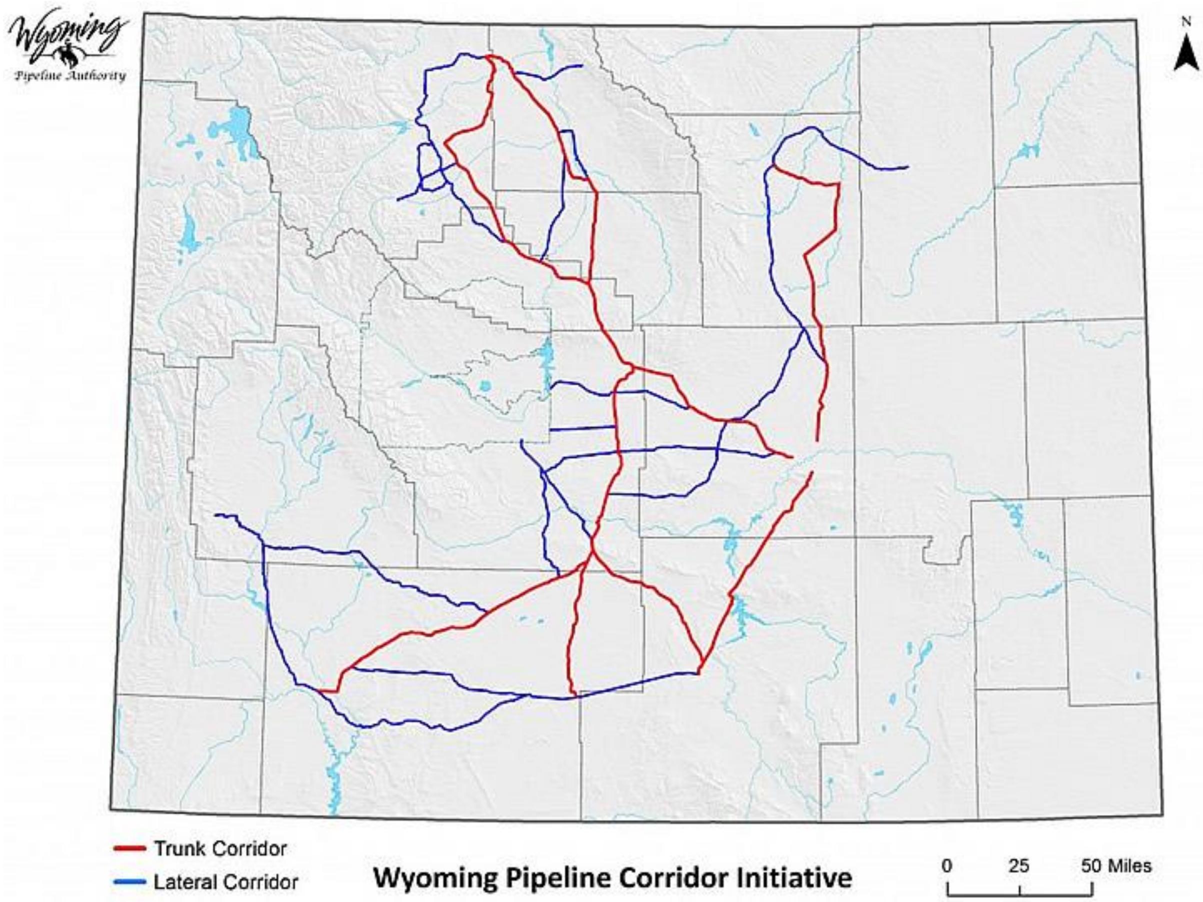
Out of the three natural gas separation plants in CO_2-rich methane (CH_4) reservoirs, two currently supply CO_2 to Denbury projects: Shute Creek, operated by ExxonMobil at BPLB, and Lost Cabin, operated by ConocoPhillips, in the eastern Wind River Basin. The third, the DKRW Advanced Fuels LLC's Medicine Bow coal-to-liquids project in the Powder River Basin, was slated to be operational with CO_2 capture and was under contract to supply CO_2 to Denbury [63] but canceled construction in May 2016 due to permitting issues. The Lost Cabin Gas Plant was purchased by Denbury in 2011 and became operational with CO_2 capture in 2013. Denbury acquired the Riley Ridge Federal Unit in late 2013 and operated the facility during part of 2014. In mid-2014, the facility was shut-in due to operational issues. [64] The locations for these sources are shown in Exhibit 2-9 and described below.

Exhibit 2-9. Rocky Mountain EOR market



The Wyoming Pipeline Authority is fostering development of state resources including natural gas, natural gas liquids, crude oil, CO_2 synthetic fuels, and water (related to energy). The state continues to work with industry and the Federal Energy Regulatory Commission advocating the development of pipeline capacity from Wyoming, in particular, CO_2 pipelines. The Wyoming Pipeline Authority published a map of CO_2 pipeline corridors depicting a proposed pipeline right-of-way (ROW) network designed to connect sources of CO_2 to existing oil fields that are suitable for EOR via CO_2 flooding. [65] These pipelines are shown in Exhibit 2-10 in yellow.

Exhibit 2-10. Wyoming Pipeline Corridor Initiative Development Plan [65]



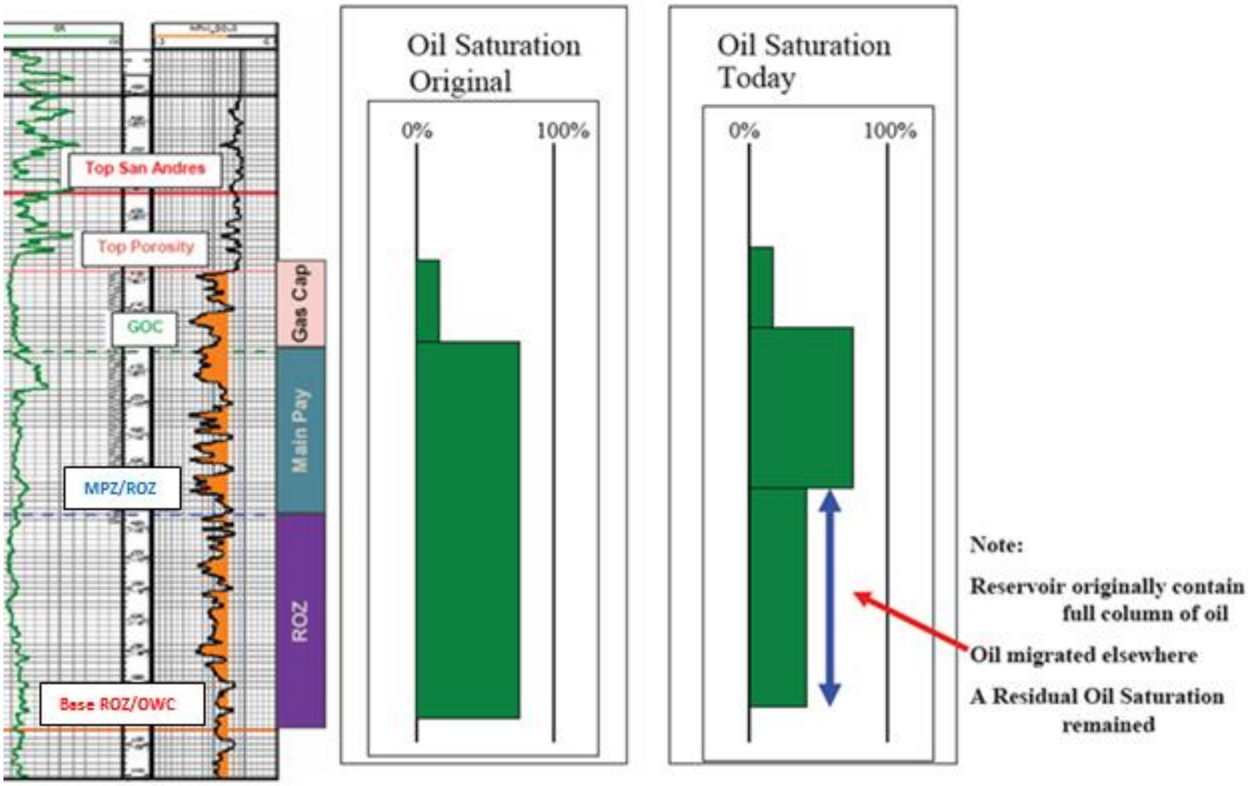
Source: Wyoming Pipeline Authority

2.4 The Future of EOR — Residual Oil Zones

The application of CO_2 EOR in residual oil zones (ROZs) holds tremendous promise to extract up to an additional 100 billion barrels of oil to increase domestic supply and improve U.S. energy security. [36] At the same time, ROZs may provide large capacity for the long-term storage of CO_2.

ROZs are depleted oil-bearing reservoirs in which natural processes (waterflooding) has displaced much of the OOIP over millions of years. [66] ROZs are located below the transition zone (TZ) beneath main pay zone (MPZ) in conventional oil and gas producing fields (known as Brownfield ROZs). ROZ can also occur in the absence of an MPZ (Greenfield ROZ). [67] Exhibit 2-11 shows the relative location of the MPZ, OWC, and ROZ, and corresponding oil saturation before and after natural water flooding. Oil saturation is essentially zero at the point labeled Base of ROZ. The MPZ, located above the OWC is where much of the mobile oil is recovered during primary and secondary operations. The TZ is located below the OWC where the oil saturation falls rapidly and produces both water and oil.

Exhibit 2-11. Residual oil zone depiction with oil saturation profile for a portion of the San Andres reservoir in the Permian Basin utilizing gamma ray (GR) (green) and neutron porosity logs (orange) [68]



While a ROZ may be laterally extensive, thick, and contain oil saturations (S_o) ranging from 20–40 percent, it can be a challenge to produce the oil economically using primary or secondary recovery techniques given that natural waterflooding has occurred extensively. [69] However, the development of ROZs have been pursued heavily in the Permian Basin of the United States. If ROZ oil saturation is near typical oil saturations left after recovery using waterflooding, which is usually greater than 20 percent (and corresponding reservoir porosity is also favorable), ROZs may be produced with the same success as tertiary CO_2 EOR. The residual oil appears to respond well to CO_2 EOR techniques, and as of 2016, the ROZ in fifteen oil fields of the Permian Basin were being exploited using CO_2 EOR technology. [70] For instance, Jamali et al. (2017) [71] indicated that several Permian Basin operators extended MPZ CO_2 EOR operations into ROZ and TZ (i.e., Brownfield ROZ development) and have been able to produce oil effectively—in the order of 12,000 barrels of oil per day. [67] [72] More recently, the Kinder Morgan Tall Cotton Field in the Permian Basin has been undergoing CO_2 EOR production in ROZ (under Greenfield ROZ development) since 2014. Allison and Melzer (2017) [73] reported that the Tall Cotton field has approximately 400 feet of ROZ with portions well over 30 percent oil saturation. In the April–June 2017 timeframe, the project produced nearly 70,000 bbl per month. Other regions outside of the Permian Basin in the U.S. believed to contain high ROZ potential include the Rocky Mountains, Mid-Continent, and California. [71] [72] While there still exists insufficient data to establish a recovery factor, recoveries from ROZs could approach 30 percent. [36]

An additional technique for ROZ production that has garnered more recent attention involves depressurization. This process involves producing large volumes of water from the upper portion of the ROZ, resulting in formational pressure drop below saturation pressure. As a result, gas separates from oil, forms a continuous phase in the reservoir, and hydrocarbon production can then occur via solution drive. [71] When the gas in the residual oil expands under depressurization, the relative volume of water and oil in the reservoir pore space also changes, thereby favorably impacting oil relative permeability that enables oil production beyond the residual saturation to a waterflood. [74] This depressurization approach has gained interest in the Permian Basin as several different operators have invested in ROZ leases in both Texas and New Mexico. [71]

3 UIC Program and Subsurface Injection Regulations

This section highlights the federal regulations developed and enforced by EPA through the UIC Program for the injection and storage of fluids into the subsurface via injection wells, as well as the state primacy program for implementing approved UIC Program requirements. These regulations apply to both CO_2 EOR operations and geologic storage of CO_2. For both injection/storage practices, sites must meet certain regulatory standards pertaining to the design, construction, operations, maintenance, demonstration of well integrity, monitoring, threat/hazard identification and risk assessment, and emergency response and preparedness to ensure safe and effective operations. [75] Additionally, both injection/storage practices discussed as part of this report face a similar set of technical challenges as part of implementation, and use similar equipment and infrastructure as part of deployment (discussed further in Section 4 and Section 5). However, the two practices do so under different UIC well classes; Class II injection wells for CO_2 EOR, and Class VI injection wells for CO_2 storage. Federal regulations pertaining to Class II and VI wells and an overview of state-specific UIC Class II regulations is discussed in the subsections below to provide perspective on the current regulations for each practice.

3.1 Federal Regulations Pertaining to the UIC Program and Well Classes

EPA is tasked with establishing and enforcing any regulations associated with the injection and storage of fluids into the subsurface. The Safe Drinking Water Act (SDWA) of 1974 establishes requirements and provisions for the UIC Program to protect public health by preventing injection wells from contaminating underground sources of drinking water (USDWs)[c] from infiltration of brine or any injected fluid. [75] The specific federal regulations pertaining to the UIC Program can be found in Title 40 of the Code of Federal Regulations (CFR). Exhibit 3-1 provides a summary of the CFR parts applicable to underground injection and disposal of fluids.

[c] A USDW is an aquifer or a part of an aquifer that is currently used as a drinking water source, or a potential groundwater source needed as a drinking water source in the future. A USDW is defined in 40 CFR 144.3 as "an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of groundwater to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 milligrams per liter total dissolved solids (TDS); and (b) Which is not an exempted aquifer." [77]

Exhibit 3-1. Federal UIC-related regulations and pertaining parts within the CFR [75]

CFR Section	Description
Part 144	UIC Program: provides minimum requirements for the UIC program promulgated under the SDWA.
Part 145	State UIC Program Requirements: outlines the procedures for EPA to approve, revise, and withdraw UIC programs that have been delegated to the states.
Part 146	UIC Program – Criteria and Standards: includes technical standards for various classes of injection wells.
Part 147	State UIC Programs: outlines the applicable UIC programs for each state.
Part 148	Hazardous Waste Injection Restrictions: describes the requirements for Class I hazardous waste injection wells.

EPA has suggested that different applications of fluid injection (i.e., CO_2 injection specifically for geologic storage, CO_2 EOR, liquid waste disposal, and solution mining) inherently involves unique technical challenges despite noticeable similarities in approach. As a result, six classes of injection wells were developed under the UIC Program, in which each class is based on the type and depth of the injection activity, and the potential for that injection activity to result in endangerment (outlined per 40 CFR 144.12) of a USDW. [76] The UIC Program provides for regulation of the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. Wells may often contain similarities in functions, construction, and operating features across well classes, allowing for more consistent application of technical requirements for each well class. [77] A summary of the six well classes is shown below:

- Class I: Wells injecting hazardous and non-hazardous, industrial, and municipal wastes below USDWs
- Class II: Wells related to oil and gas production, mainly injecting brine and other fluids, as well as CO_2 for EOR applications
- Class III: Wells injecting fluids associated with solution mining of minerals, such as sodium chloride and sulfur, as well as for in situ uranium leaching
- Class IV: Wells injecting hazardous or radioactive wastes into or above USDWs (generally only used for bio-remediation). This well class was banned by EPA in 1984
- Class V: Injection wells not included in Class I through Class IV that are typically used as experimental technology wells. They range from simple shallow wells to complex experimental injection technologies
- Class VI: Class of injection wells specifically for long-term geologic storage of CO_2

3.1.1 EOR Using UIC Class II Wells

As introduced in Section 2, Class II wells are used to inject fluids related to oil and gas production into the subsurface. Currently, CO_2 EOR is regulated by UIC Class II wells (40 CFR 146

Subpart C). Class II UIC regulations require specific well construction, reservoir management, and monitoring techniques to track the use of CO_2 as an injectate into the producing formation. [3] Regulations pertaining to UIC Class II wells encompass Part 144 and Part 146 of the CFR. The relevant parts relating to the technical requirements (e.g., operations, monitoring, and financial responsibility) of UIC Class II wells include:

- 40 CFR 144 Subpart A – General Provisions (§§ 144.1 – 144.8)
- 40 CFR 144 Subpart B – General Program Requirements (§§ 144.19)
- 40 CFR 144 Subpart C – Authorization of Underground Injection by Rule (§§ 144.21 – 144.22, §§ 144.25 – 144.28)
- 40 CFR 146 Subpart A – General Provisions (§§146.1 – 146.10)
- 40 CFR 146 Subpart C – Criteria and Standards Applicable to Class II Wells (§§ 146.21 – 146.24)

In addition to the Class II-related regulations listed above, any facility that injects a CO_2 stream into the subsurface must also meet the requirements of EPA finalized regulations for "Mandatory Reporting of Greenhouse Gases for Injection and Geologic Storage of Carbon Dioxide" (referred as Subpart UU under 40 CFR 98.470 – 478). Subpart UU only requires facilities to report the mass of CO_2 received for purposes of enhanced oil and gas recovery. These reporting requirements are meant to provide EPA with a consistent greenhouse gas (GHG) activity record. Additionally, data received from this reporting process are believed to help inform EPA for future decisions under the Clean Air Act pertaining to the use of CCS, specifically, for mitigating anthropogenic CO_2 emissions. [78] They also ensure that appropriate consideration is given to key monitoring elements of CO_2 injection projects including: [79]

- Determination of quarterly flow rate of CO_2 received by pipeline
- Determination of quarterly mass or volume of CO_2 received by container
- Determination of a quarterly concentration of CO_2 that is representative of all CO_2 received in that quarter

These regulations are meant to complement the UIC Class II well regulations. Specifics of GHG reporting requirements for geologic storage projects are contained in CFR Title 40, Part 98.[d]

3.1.2 CO_2 Storage Using Class VI Wells

In December 2010, EPA finalized minimum federal requirements under the SDWA for injection of CO_2 for geologic storage, primarily in saline reservoirs. Prior to these requirements, early research in CO_2 geologic storage used either a Class I or Class V well and injection of CO_2 into the subsurface used Class II wells if the goal was EOR. Like the other UIC well classes, Class VI regulations are designed to prevent potential leakage and endangerment to USDWs. This final rule applies to owners and/or operators of wells that will be used to inject CO_2 into the subsurface for long-term storage. [80] This new Class VI well classification contains conditions

[d] More information on EPA's GHG Reporting Program can be found at: https://www.epa.gov/ghgreporting.

designed to protect USDWs by requiring site operators to adhere to specific requirements (outlined in 40 CFR 146 Subpart E) related to siting, construction, operation, testing, monitoring, and closure. These regulations address the unique nature of CO_2 injection for geologic storage, including the relative buoyancy of CO_2, subsurface mobility, corrosivity in the presence of water while under subsurface pressure and temperature conditions, as well as the large injection mass anticipated at geologic storage projects. [5] The rule provides owners or site operators the flexibility to develop CO_2 storage projects at various depths and in various geologic settings in the United States. [81] Regulations pertaining to UIC Class VI wells encompass Part 144 and Part 146 of the CFR. The relevant parts pertaining to the technical requirements (e.g., operations, monitoring, and financial responsibility) of UIC Class VI wells include:

- 40 CFR 144 Subpart A – General Provisions (§§ 144.1; 144.3 – 144.8)
- 40 CFR 146 Subpart A – General Provisions (§§ 146.1 – 146.9)
- 40 CFR 146 Subpart H – Criteria and Standards Applicable to Class VI Wells (§§ 146.81 – 146.95)

In addition to the Class VI-related regulations listed in the bullets above, CO_2 storage owners/operators must also meet the requirements of EPA finalized regulations for "Mandatory Reporting of Greenhouse Gases for Injection and Geologic Storage of Carbon Dioxide" (referred as Subpart RR under 40 CFR 98.440 – 449). Subpart RR reporting requirements are meant to provide EPA with a consistent GHG activity record for all future geologic storage projects. They also ensure that appropriate consideration is given to key monitoring elements of geologic storage projects. Facilities carrying out geologic storage operations must report basic information on the amount of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; and report the amount of CO_2 stored. [82] The MRV plan must specify a strategy for detecting and quantifying surface release of CO_2 and an approach for establishing baselines for monitoring CO_2 surface releases. The MRV plan identifies the maximum monitoring area (MMA) and the active monitoring area (AMA). The MMA is defined as the area that must be monitored and is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized. It also includes an additional all-around buffer zone of at least one-half mile. The AMA is defined as an overlay between 1) the area projected to contain the free phase CO_2 plume at the end of a specific timeframe established by the operator, plus an all-around buffer zone of one-half mile or greater if known release pathways extend laterally more than one-half mile, and 2) the area projected to contain the free phase CO_2 plume at the end of five years after the specific monitoring timeframe has passed. [83] This timeframe established as part of the AMA allows operators to phase in monitoring so that during any given time interval, only that part of the MMA in which leakage might occur needs to be monitored. [82] The MRV plan must be developed by the project supervisor and approved by the EPA Administrator. Once the required reports are submitted to EPA, they will be evaluated to determine if the CO_2 plume is being properly contained and safely monitored. The boundaries of the AMA must be periodically re-evaluated and approved by the EPA Administrator. As the AMA increases, the monitoring, verification, and accounting (MVA) plan will need to be reviewed to better assure proper containment. [83]

These regulations are meant to complement the UIC Class VI permit regulations. Specifics of GHG reporting requirements for geologic storage projects are contained in CFR Title 40, Part 98.[d]

3.1.3 Side-by-side Regulatory Comparison for Class II and Class VI Wells

Fluid injection using UIC Class II wells, particularly when CO_2 is used for EOR, provides a unique analog that can be used to help address technical and policy-related questions concerning geologic CO_2 storage in saline-bearing formations using UIC Class VI wells. Class II wells may be converted to Class VI wells if owners or operators transition to injecting CO_2 into depleted oil and gas reservoirs for long-term storage (opposed to enhanced hydrocarbon recovery applications, or Class II disposal wells). This is particularly true when there is an increased risk to USDWs compared to Class II CO_2 EOR operations. [84] This section presents a side-by-side comparison of key components within the regulations for Class II and Class VI wells (Exhibit 3-2). The technical operational criteria (for instance, siting and characterization, well construction, area of review [AoR]) vary for either Class II or Class VI wells depending on the intended operation, production, or storage. Exhibit 3-2 provides the summary of the current mandatory technical requirements as indicated by 40 CFR 146 Subparts A, C, and H, as well as 40 CFR 144 Subpart C for well types most directly applicable to CO_2 EOR operations. These UIC regulations are based on the concept that injection into properly sited, constructed, and operated wells is a safe way to inject and dispose of fluids (like produced brine or CO_2) into the subsurface. [75]

Exhibit 3-2. Summary of technical requirements based on the governing regulations for Class II and Class VI UIC injection wells

Requirement	Class II	Class VI
Siting and Characterization	• Site new wells in such a fashion that they inject into formation that is separated from any USDW by confining zone that is free of known open faults or fractures within the AoR • Demonstrate the presence and adequacy of injection and confining zones by presenting information on geologic formations • Create map showing injection well or project area for which permit is sought and applicable AoR • Develop maps, cross-sections, and a list of penetrations into the injection zone, and of regional geology • Perform specific wireline log runs and tests to inform well construction compatibility with the subsurface	• Demonstrate wells will be sited in areas with suitable geologic system comprising injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive total anticipated volume of CO_2 stream and confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in confining zone(s) • Identify and characterize additional zones, if required • Run appropriate wireline logs, surveys, and tests to determine or verify depth, thickness, porosity, permeability, and lithology of, and salinity of any formation fluids in all relevant geologic formations to ensure conformance with injection well construction requirements • Complete extensive site characterization, including the analysis of wireline logs, maps, cross-sections, USDW locations; determining injection zone porosity, identifying any faults, and accessing seismic history of area
Area of Review (AoR)	• Determine AoR by using mathematical model, such as modified Theis equation, to calculate zone of endangering influence or fixed radius of at least one-quarter mile around an injection well or width of one-quarter mile for circumscribing area around injection area	• Determine AoR by computational model, which accounts for the physical and chemical properties of all phases of the injected CO_2 stream. This modeling is based on available site characterization, monitoring, and operational data • Identify and address any improperly completed or abandoned wells through corrective action within AoR

Requirement	Class II	Class VI
	• Identify all known wells that penetrate the proposed injection zone, or all known wells that penetrate formations that may be affected by the increase in pressure • Recognize and address any improperly completed or abandoned wells within AoR	• Delineate the AoR over the project lifetime (at least every five years)
Well Construction	• Case and cement wells to prevent movement of fluids into or between USDWs • No specific regulations for tubing and packer requirements in 40 CFR 146 Subpart C	• Confirm all well materials are compatible with fluids with which the materials may be expected to come into contact • Verify surface casing extends through base of lowermost USDW and is cemented to surface using single or multiple strings of casing and cement • Ensure at least one long string casing extends to injection zone and is cemented by circulating cement to surface in one or more stages • Determine cement and cement additives are compatible with CO_2 stream and formation fluids and are of sufficient quality and quantity • Verify tubing and packing materials are compatible with fluids with which materials may be expected to come into contact. Injection conducted through the tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director • Fill annulus between tubing and long string casing with non-corrosive fluid
Operation	• Calculate injection pressure to assure it does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs during injection • Prohibit injection between the outermost casing protecting USDWs and the wellbore	• Ensure compliance with approved AoR and Corrective Action Plan and Emergency and Remedial Response Plan • Ensure injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) • Utilize alarms, automatic surface shut-off systems, and down-hole shut-off systems that initiate when operational parameters diverge beyond permitted ranges
Mechanical Integrity Testing (MIT)	• Conduct internal and external MITs every five years • Evaluate absence of significant leaks by monitoring tubing-casing annulus pressure with sufficient frequency, pressure test with liquid or gas, or records of monitoring showing absence of significant changes in relationships between injection pressure and injection flow rate for certain specified types of enhanced recovery wells • Use results of temperature or noise logs or cementing records demonstrating presence of adequate cement to determine absence of significant fluid movement	• Evaluate absence of significant leaks by initial annular test and continuous monitoring of injection pressure, rate, injected volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume • Use tracer survey or temperature or noise log at least once a year to determine the absence of significant fluid movement • Run casing inspection log to determine presence or absence of corrosion in long string casing, if required
Monitoring	• Monitor nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics • Complete periodic injection pressure, flow rate, and cumulative volumes (produced and injected) monitoring weekly for disposal wells and monthly for EOR • Perform annual fluid chemistry as needed or required by permit • No specific regulations for record keeping in 40 CFR 146 Subpart C	• Ensure compliance with approved Testing and Monitoring Plan • Use continuous recording devices to monitor the injection pressure, rate, volume and/or mass, and temperature of CO_2 stream; pressure on the annulus between the tubing and long string casing, and annulus fluid volume • Monitor corrosion of well materials • Complete pressure fall-off test at least once every five years • Perform periodic monitoring of groundwater quality and geochemical changes above confining zone(s) or additional identified zones

Requirement	Class II	Class VI
		• Test and monitor to track extent of CO_2 plume and presence of elevated pressure by using direct or indirect methods • Perform surface air monitoring and/or soil gas monitoring to detect movement of CO_2 that could endanger a USDW, if required • Review Testing and Monitoring Plan periodically; review cannot be conducted less than once every five years • Provide quality assurance and surveillance plan for all testing and monitoring requirements
Injection Well Plugging	• Provide 45-day notice before plugging and abandonment • Plug well with cement and utilize Balance Method, Dump Bailer Method, Two-Plug Method, or other alternative method to place cement plugs • Confirm abandoned well is in state of static equilibrium with mud weight equalized top to bottom	• Provide 60-day notice in writing before plugging • Ensure compliance with Injection Well Plugging Plan • Flush each well with buffer fluid, determine bottom-hole reservoir pressure, and perform final external MIT • Submit plugging report within 60 days after plugging
Proof of Containment and Post-Injection Site Care (PISC)	• No specific regulations in 40 CFR 146 Subpart C	• Monitor site following cessation of injection to show position of CO_2 plume and pressure front and demonstrate that USDWs are not being endangered • Maintain PISC for 50 years or until proof of non-endangerment to USDWs is demonstrated • Ensure compliance with approved PISC and Site Closure Plan
Site Closure	• No specific regulations in 40 CFR 146 Subpart C	• Provide at least 120-day notice before site closure • Plug all monitoring wells in manner that will not allow movement of injection or formation fluids that endanger USDW • Submit site closure report within 90 days of site closure
Financial Responsibility	• Provide certificate that assures, through performance bond or other appropriate means, the resources necessary to close, plug, or abandon the injection well	• Demonstrate and maintain financial responsibility by using instrument(s); such as trust fund, surety bond, letter of credit, insurance, self-insurance (i.e., financial test and corporate guarantee), Escrow Account, or any other instrument(s); to cover costs of corrective action, injection well plugging, PISC and site closure, and emergency and remedial response • Update cost estimates of performing corrective action on wells in AoR, plugging injection well(s), PISC and site closure, and emergency and remedial response periodically to account for any amendments to plans (AoR and corrective action, injection well plugging, PISC and site closure, or emergency and remedial response)

3.2 State and Regional Primacy Control of UIC Injection Wells

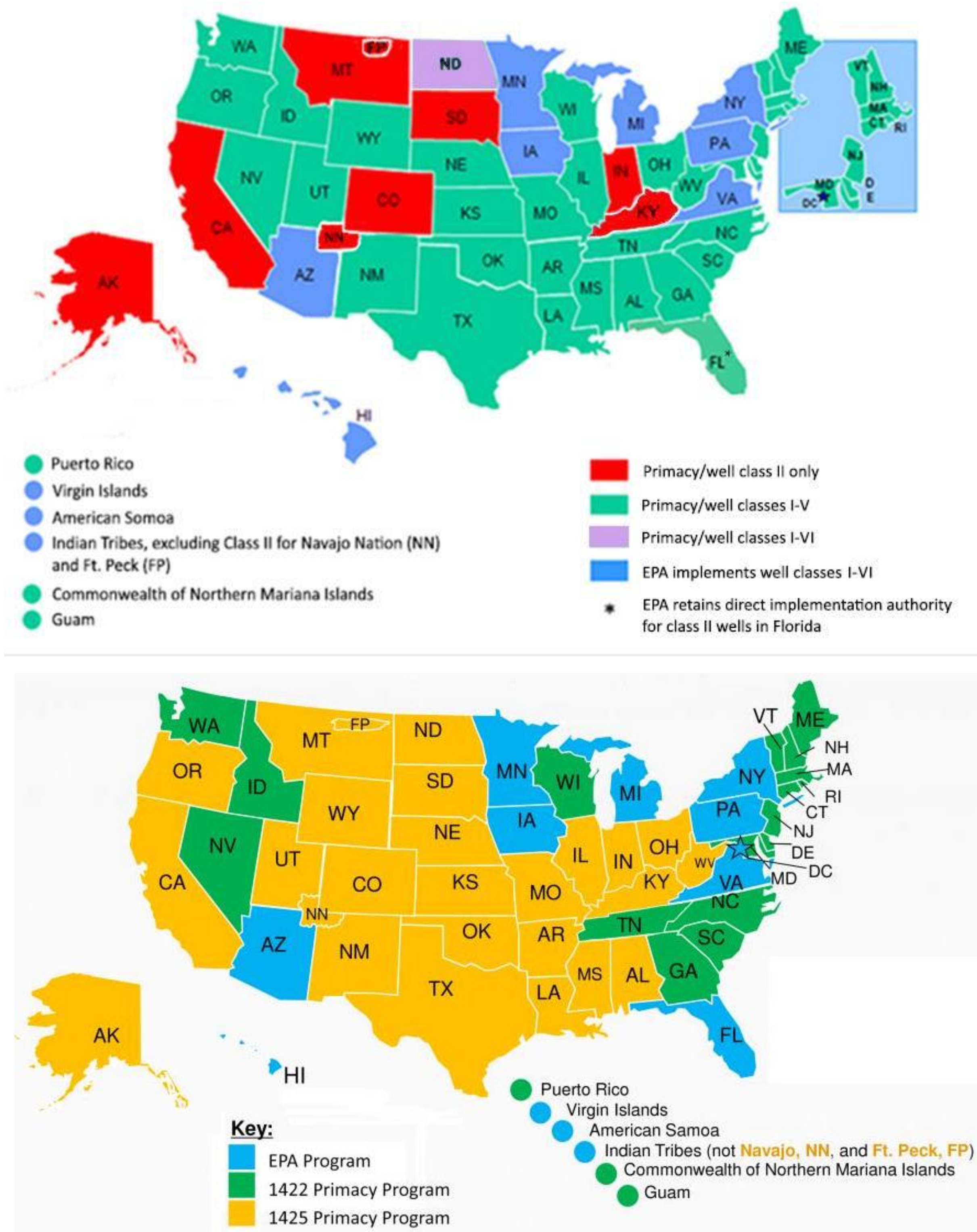
In addition to the federal requirements highlighted in Exhibit 3-2, many states have either enacted CCS requirements or are currently doing so. [80] EPA encourages state and regional governments, as well as tribes and territories, to seek primary enforcement responsibility or "primacy" for UIC well permitting, including UIC Class II and VI CO_2 injection wells. EPA asserts that state and regional entities are better equipped to address local concerns and handle geological assessments in their respective areas. State or regional primacy includes the right to approve permit applications and revisions, control over permitting decisions, and responsibility for oversight of injection wells.

Primacy programs are established under Section 1422 and Section 1425 of the SDWA. These sections are explained in more detail below: [85]

- SDWA Section 1422 (42 U.S.C. §300h-1) enables states and American Indian Tribes to have primary enforcement responsibility for underground injection controls if the state/tribe can meet the minimum EPA requirements for authorization to assume primary enforcement responsibility. Programs authorized under this section have primacy for Class I, II, III, IV, V, and VI wells, and applicants may apply for primacy for all well classes, Class I–Class V only, or Class VI only.
- SDWA Section 1425 (42 U.S.C. §300h-4) describes optional demonstrations a state may make for the portion of the UIC Program related to oil and natural gas operations. This section allows EPA to approve existing state Class II (oil and gas) programs if the state can show that the program is effective in preventing endangerment of USDWs but does not require meeting EPA's minimum requirements.

As of May 2018, 34 states and three territories have EPA-approved primacy programs for well classes I, II, III, IV, and V. [85] In addition, seven states and two tribes have applied for and received primacy approval for Class II wells only (Exhibit 3-3). Effective March 21, 2017, the Commonwealth of Kentucky was granted primary enforcement responsibility for UIC Class II injection wells located within the state. [86] If a state/tribe/territory does have primacy for a given well type, the specific requirements of that state/tribe/territory could be equally, and possibly more stringent than EPA minimum.

Exhibit 3-3. National maps featuring states, territories, and tribes UIC primacy status (top), and Class II-specific primacy status (bottom) [85]



Source: U.S. EPA

EPA is currently accepting new applications for state control of UIC wells and program revisions to existing primacy agreements to include Class VI well permitting rights; in April 2018, EPA issued a final rule for the state of North Dakota to assume primary enforcement authority for regulating Class VI injection wells in the state, except for those located on American Indian lands. [85] This rule came in response to the state of North Dakota submitting a program revision application in June 2013 to add Class VI injection wells to its SDWA Section 1422 UIC Program. [87] The state of Wyoming has developed regulations pertaining to Class VI injection wells and applied for UIC Class VI primacy. [88] [89] As of December 2018, the application is under review by EPA. States with no primacy agreements in place, or with primacy over Class II wells only, may choose to apply for primacy over all UIC well classes (I-VI) or over UIC Class VI wells only. States that already have primacy over UIC well Class I–Class V may seek to add primacy for Class VI wells by applying for a program revision. [85]

3.2.1 State Financial Incentives

States may provide tax credits for CO_2 EOR and geologic storage. These could take the form of corporate income tax reduction, exemptions from property and sales taxes on CO_2 EOR and geologic storage machinery and equipment, and the reduction of severance taxes on oil produced through CO_2 EOR. Texas and Kansas are the only two of the top five active EOR states that provide tax incentives for EOR.

Texas established a tax rate reduction for oil producers who use anthropogenic CO_2 for new or expanded EOR projects (2.3 percent versus the standard rate of 4.6 percent) for a period of ten years after certification from the Railroad Commission of Texas. [90] The stipulation for this certification is that at least 99 percent of the CO_2 will remain stored for 1,000 years. [91] Texas also created sales and use tax exemptions for the installation costs of carbon capture technology for anthropogenic sources that will capture and use CO_2 for EOR, or geologically stored with the reasonable expectation that at least 99 percent of the CO_2 will remain stored in the subsurface and from the atmosphere for at least 1,000 years. [92]

Kansas established tax incentives for underground storage of CO_2, including income tax reductions and property tax exemptions. The taxpayer may deduct from adjusted gross income amortized costs of machinery and equipment for CO_2 capture, sequestration, or utilization for ten years. There is also a property tax exemption for up to five years on all CO_2 capture, sequestration, or utilization property, including electrical generation units. [93]

Operators of EOR projects in Oklahoma can apply for an exemption from the levy of gross production tax on the incremental production of oil or other liquid hydrocarbons attributable to the working interest owners of an EOR project. [94]

3.2.2 State-Specific UIC Class II Regulation Highlights

When a state or tribe has primacy for the UIC Program, it means that the state or tribe has the lead responsibility for administering and enforcing oversight of corresponding wells. Primacy affords the states and tribes the opportunity to develop their own specific regulations, which, by law, must be equally or more stringent than federal UIC regulations. [80] [85] Primacy enables states to then develop requirements that could be tailored to a state's circumstances (like varying and diverse geology and hydrology from state to state, and region to region) to assure underground injection safety.

The five states with the most Class II recovery wells are shown in Exhibit 3-4 below. [95] The wells included are not exclusive to CO_2 EOR; they include wells from other recovery applications (like thermal or chemical approaches). A brief overview of the Class II regulations in each of these five states can be found in Appendix C: Overview of the Five States with the Most Class II Wells.

Exhibit 3-4. Summary of Class II recovery wells in top five states for 2017 [95]

State	Number of Class II Recovery (EOR) Wells	Percent of Total U.S. Class II EOR Wells
California	53,804	37%
Texas	40,071	28%
Kansas	13,188	9%
Illinois	6,964	5%
Oklahoma	6,825	5%
Total, Top Five States	**120,852**	**84%**
Total, United States	**143,587**	**100%**

4 Overview of CO_2 EOR Implementation: Screening, Permitting, Operations, and Closure

An understanding of CO_2 EOR operations is needed to appreciate potential risks for CO_2 leakage, and to effectively evaluate the industry as an analog for carbon storage operations. There are significant differences in site-selection, permitting, and operations between CO_2 EOR development and other subsurface injection and/or disposal regimes, like for Class VI injection wells (and other UIC well types for that matter). The decision to embark on CO_2 EOR is based on a geologic and engineering assessment of the reservoir, and the economics of the incremental oil production that is anticipated.

The siting, construction, permitting, operating, and monitoring requirements for CO_2 EOR are typically less stringent using Class II wells than compared to Class VI wells for geologic storage; however, in the pursuit of an effective operation, the necessary geologic properties and characteristics are often similar to those for CO_2 storage. Additionally, the potential approaches a site operator may undertake to characterize a site for a potential Class VI well are similar to those for a Class II EOR well. For example, some key success criteria for CO_2 storage (as highlighted in Section 5.3) are capacity, containment, and injectivity. These characteristics align to those required for CO_2 EOR operations as well; and the approaches one would take to infer about the geologic properties that dictate those success criteria would be inherently the same for the two practices.

A major difference between CO_2 EOR using Class II wells and geologic storage of CO_2 using Class VI wells is that reservoirs used for CO_2 EOR are already proven and well characterized since they have likely undergone primary and secondary production (Greenfield ROZs may be the exception). Plus, candidate reservoirs for CO_2 EOR have demonstrated containment by storing hydrocarbons in place for millennia. However, reservoirs in saline-bearing formations, which would be candidates for CO_2 storage, have yet to be discovered, so their properties are not nearly as well known or understood. Therefore, saline-bearing formations targeted for CO_2 storage are expected to require extensive initial characterization efforts for Class VI wells in order to fully identify and understand properties that allude to sufficient containment, capacity, and injectivity (not dissimilar to saline formation development in the natural gas storage industry [96]). Another major difference between the two practices is the volume of infrastructure required. For instance, successful CO_2 EOR operations require extensive infrastructure that includes CO_2 pipelines, injection wells, production wells, and related surface handling facilities. [97] Commercial-scale CO_2 storage is expected to also utilize CO_2 pipelines and contain surface facilities (which could include produced water treatment), but the relative number of injection wells is expected to be substantially less, and monitoring activities/infrastructure considerably higher. Additionally, production wells may be applicable to CO_2 storage operations as a means for producing water for active reservoir management, CO_2 plume control, and pressure alleviation (CO_2 production not expected), but the volume of production wells would likely not approach the level needed in CO_2 EOR flooding.

The selection of sites suitable for CO_2 EOR projects depends on several factors, including the potential for recovery of additional oil in place, MMP being able to be met, and determination that geological complexity would not hinder the ability of the CO_2 to contact the crude oil (e.g., if waterflooding was successful, CO_2 flooding will also likely be successful). Not all sites are suitable for CO_2 EOR operations, so the assessment of prospective CO_2 flooding is conducted using a systematic screening approach. If a site that is screened is deemed a candidate for CO_2 EOR, then follow-on permitting and operations would likely follow. A basic CO_2 EOR project workflow is presented in the bullets below:

- **Reservoir screening and selection:** The site screening phase involves evaluating reservoirs that are potentially suitable for CO_2 EOR operations based on the analyses of readily accessible data. Potential reservoirs that meet the necessary screening criteria can be selected for further, detailed characterization of the reservoir for EOR operations.
- **Permitting:** Utilizes data from site screening and characterization to build a CO_2 EOR permit application for a selected site. Once an injection permit is approved, a project will begin site preparation for eventual injection operations.
- **Operations:** Active transportation and injection of CO_2 and site monitoring. Operations also include handling and management of produced fluids (like oil, CO_2, and water).
- **Closure of injection operations:** Injection has ceased and the injection well(s) will be plugged, the associated equipment will be removed.

The following subsections are intended to 1) summarize considerations for a potential CO_2 EOR reservoir regarding screening and selection criteria, 2) discuss typical CO_2 injection designs and broadly compare against CO_2 storage designs, 3) summarize approaches to screen reservoirs for economic potential based on newly-acquired reservoir data, 4) review CO_2 EOR operations and monitoring practices, and 5) summarize site closure considerations. Where applicable, key points will be discussed where either substantial overlap or dissimilarities exist with CO_2 EOR as an analog to CO_2 storage. Additionally, factors discussed that could be a risk of CO_2 leakage will also be noted.

4.1 Reservoir Screening and Selection

Both siliciclastic and carbonate[e] conventional oil reservoir lithologies are considered suitable for CO_2 EOR applications. The oil recovery under CO_2 EOR is influenced by the associated fluid characteristics (e.g., viscosity and density), rock characteristics (e.g., wettability, porosity, and permeability), and structural or stratigraphic features (e.g., faults and other barriers to oil or gas movement). Ultimately, reservoir characterization and understanding leads to improved estimates of the remaining oil in place, as well as to a better understanding of potential reservoir behavior in response to a CO_2 flood. [30]

Determination of the best reservoir candidates for CO_2 EOR is done by screening rock and fluid characteristics to identify if favorable reservoir depths, pressures, temperatures, oil in place, oil

[e] Siliciclastic sedimentary rock is derived from the detritus left behind from the weathering of igneous, metamorphic, and other sedimentary rock. [286] Carbonates are sedimentary rocks which were deposited in marine-based environments. They are composed fragments from marine organisms, like skeletons, coral, and algae, and consist mostly of calcium carbonate. The calcium carbonate is chemically active compared to the sand which makes sandstones, prominent of siliciclastic rock. [287]

gravity, and viscosity ranges exist. [98] Not all reservoirs that contain hydrocarbons in place may be considered suitable candidates for CO_2 EOR. Data collection through compilation of existing datasets, as well more detailed site characterization efforts (which may include acquisition of new data through seismic surveys, well logging, core analysis, and injectivity tests) provides the foundation for screening reservoirs. Results from characterization efforts will allude to a site's suitability and whether it contains favorable conditions for CO_2 EOR following a systematic screening approach that consists of the following evaluations:

- Reservoir rock and fluid properties
- MMP
- Incremental oil recovery forecast
- Reservoir heterogeneity

The minimum federal siting criteria for operations using Class II wells that owners and operators must demonstrate have been outlined in Exhibit 3-2 in Section 3.1.3 above. [84] Ultimately, these requirements mandate key characteristics that make a Class II well site viable for CO_2 EOR from an operational, safety, and water protection perspective. While a reservoir's proven caprock provides containment, proper well construction and injection practices are necessary to prevent migration of CO_2. Other considerations include reviewing existing wells within the anticipated AoR to ensure all penetrations of the injection and subsequent confining zone(s) do not pose a leakage conduit threat. However, for a potential CO_2 EOR site to be economically favorable and worth developing, it must contain additional geologic properties that allude to the site's' ability to produce oil via CO_2 EOR which are additional to those required under UIC requirements for Class II wells.

Assessments of the large-scale CO_2 EOR projects currently in operation across North America have led to the identification of optimal reservoir characteristics for a successful miscible CO_2 EOR flood as documented by Taber, Martin, and Seright (1997), [99] as well as by Shaw and Bachu (2002). [100] The range of favorable reservoir characteristics from these projects are listed in Exhibit 4-1. [43] The following subsections of this report describe the context of these variables as they relate to CO_2 EOR projects. Where appropriate, engineering equations are used and described to associate a given parameter to others within CO_2 EOR systems. This approach facilitates comparison of CO_2 EOR considerations to those of CO_2 storage (described in more detail in Section 5).

Exhibit 4-1. EOR reservoir characteristics for miscible CO_2 flood [99] [100]

Reservoir and Oil Properties	Value range, average
Oil Gravity - American Petroleum Institute (API)	22 to over 40° API
Oil Composition	Higher percentage of C_5 to C_{12}
Original Pressure	1,100–over 1,500 psia
Oil Viscosity	Less than 2 to 15 cP
Oil Saturation	22–55% pore volume
Permeability	Greater than 5 mD
Depth	Over 2,000 ft
Temperature	Less than 250 °F

4.1.1 CO_2-Oil Miscibility and Pressure

CO_2 EOR operations recover the oil still trapped in a reservoir after waterflooding by creating miscibility between the residual oil and the injected CO_2. [101] Miscible CO_2 EOR is a multiple contact process referred to as a condensing/vaporizing mechanism in which the CO_2 first condenses into the oil (condensing gas-drive process), while the lighter oil components vaporize into the CO_2 (vaporization gas-drive process), giving the CO_2 a density similar to oil, and thus making it soluble in the oil. [102] This results in the two fluids mixing, eliminating capillary forces from the displacement process, creating the favorable properties of low viscosity, enhanced mobility, and low interfacial tension that allows the CO_2 to displace the oil from the reservoir's pore space. [2] [103] Therefore, MMP, the reservoir pressure in which miscibility occurs with reservoir oil at reservoir temperature, is the most critical constraint for the applicability of miscible CO_2 EOR. [30] [98] For optimum recovery, the reservoir pressure should be above the thermodynamic MMP; under these conditions, the ratio between reservoir pressure and MMP would be greater than 1. [100] [103] [104] However, miscible CO_2 EOR floods have been noted as feasible with ratios near 0.95 (reservoir pressure/MMP). These pressure ratios serve as additional screening criteria for reservoir suitability to CO_2 EOR. [100] It is recommended that the average reservoir pressure at the start of the flood should be at least 200 pounds per square inch (psi) above the thermodynamic MMP if possible. [104] However, this value can vary depending on the reservoir properties, such as oil gravity, oil composition, and temperature, [22] [104] as well as potential fracture pressure limitations.

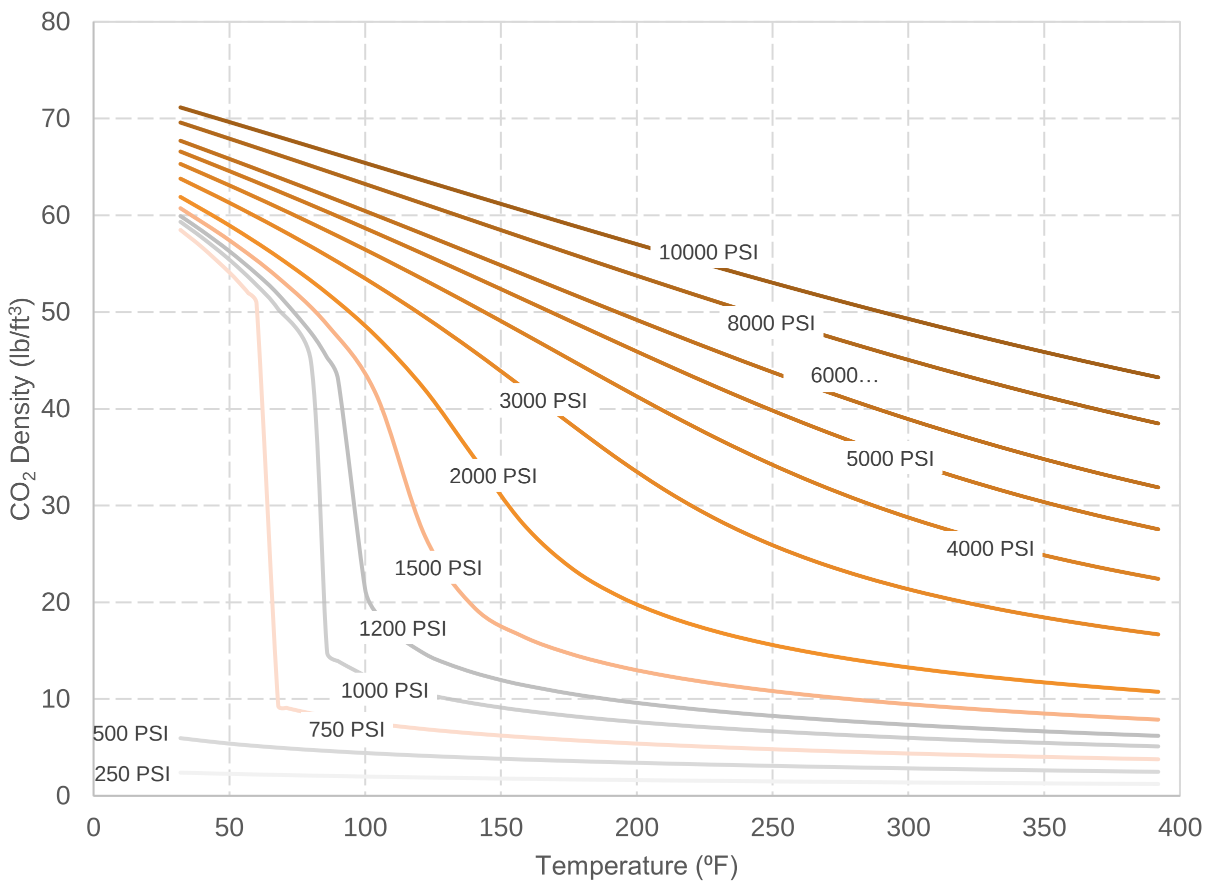
For miscible displacement to occur, reservoir depth must be great enough to enable injection pressures above the MMP (as pressure typically increases with depth).[f] Depth is also important for determination of fracture pressure (P_{frac}); for a suitable CO_2 EOR reservoir, P_{frac} must be greater than the MMP to avoid unintended induced rock fracturing, as well as to ensure miscibility.[g] Depth is also a relevant parameter because of the impact of temperature and pressure on properties of CO_2 (Exhibit 4-2). CO_2 becomes supercritical at 1,070 psig and 88 °F,

[f] Hydrostatic pressure gradients typically used can range between 0.433 (low-salinity settings) to 0.465 (higher-salinity settings) psi/ft. [288]

[g] A widely used fracture pressure gradient is 0.7 psi/ft of depth [289] but 0.6 psi/ft is also a viable gradient. [116]

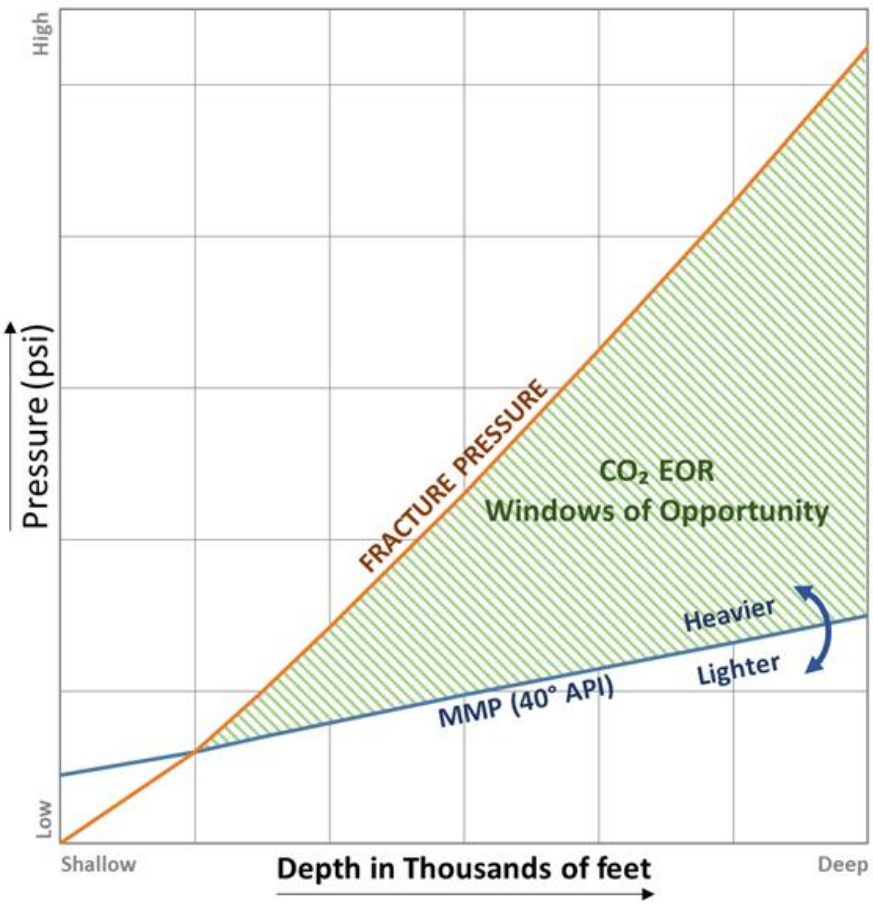
when gas and liquid are no longer separate phases and the CO_2 density is high enough for it to be an effective solvent for oils that contain significant volumes of intermediate hydrocarbons. According to Jarrell et al. (2002), [105] CO_2 in the supercritical phase can better extract hydrocarbon components from oil than gaseous CO_2. [30]

Exhibit 4-2. CO_2 density variation as a function of pressure and temperature calculated using equation of state from Duan et al. (1992) [106]



For a typical geothermal gradient (roughly 15 °F/1,000 ft depth [107]), the minimum depth needed to ensure CO_2 would remain in the supercritical state is approximately 1,900 to 2,000 ft (assuming surface temperature is 60 ºF). Pressure and temperature gradients could be substantially higher in some settings than those presented in the preceding text, making shallower formations with higher temperature and pressure gradients potential candidates for CO_2 EOR. Further, the density, and therefore the solubility, of CO_2 in oil decreases with increasing temperature, but also increases with increasing pressure (Exhibit 4-2). Therefore, the MMP required for given oil must increase as reservoir temperatures increase. Since reservoir temperatures normally increase with depth, the MMP must also increase with depth. Fortunately, the pressure required to fracture reservoirs increases much faster (0.7 psi/ft) than hydrostatic pressure (0.433 to 0.465 psi/ft) and temperature (15 °F/1,000 ft) with depth. As a result, there are windows of opportunity for CO_2 EOR in most reservoirs where there is a favorable discrepancy between the MMP and fracture pressure (Exhibit 4-3). [99] An upper temperature limit is normally used to ensure miscibility with reference to the specific reservoir fracture pressure. In practice, the lower oil gravity limit for achieving miscibility ranges between 22–24° API.[h]

Exhibit 4-3. CO_2 EOR window of opportunity concept featuring the relationship of oil API gravity and fracture pressure as a function of depth [99]



Various approaches can be used to determine the MMP in CO_2 injection processes. These include, but are not limited to, slim tube displacement testing, rising bubble testing, vapor-liquid equilibrium studies, slum tube composition simulators, and empirical correlation. The most common (and reliable) method to calculate MMP between the reservoir oil and a given injection/displacing solvent (like CO_2, methane, or other types of potential solvents) is the slim tube displacement test. [108] The slim tube displacement test is a laboratory test in which a tube is packed with sand or glass beads and saturated with a sample oil at the reservoir temperature. [109] Solvent injection is performed at several test pressures. [110] The MMP is then determined by measuring the fluid recovered as a function of varying pressures. [111]

[h] API gravity is a measure of how light or heavy petroleum liquids are compared to water at standard conditions. API gravity is expressed in degrees by the following equation (G = specific gravity of the petroleum liquid of concern at 60 °F)

$$API\ gravity = \frac{141.5}{G} - 131.5$$

Since slim tube tests are typically expensive and time-consuming endeavors, but empirical-based correlation can be used to provide a first pass estimation of MMP for site screening. [112] [113] Several researchers have performed this type of analysis to estimate MMP for a variety of different oils and CO_2. [98] [114] [115] As one example, consider an adaptation of the Cronquist correlation (which is one of several equations available to estimate MMP) by ARI, [116] which can be used to determine MMP based on reservoir temperature and the molecular weight of pentanes and heavier fractions (C_{5+}) of the reservoir oil as a function of API gravity. [30]

$$MMP = 15.988 \times T^{(0.744206+0.0011038 \times C_{5+})}$$

Equation 4-1

$$C_{5+} = 4247.98641 \times API^{-0.87022}$$

Equation 4-2

Where:

MMP = minimum miscibility pressure (psia)

T = reservoir temperature (^{o}F)

C_{5+} = molecular weight of hydrocarbons pentane and heavier

API = API gravity of the oil (degrees)

These equations suggest that MMP will increase as with increasing reservoir temperature or lower oil gravity. For instance, when CO_2 density is high enough to vaporize C_5 through C_{30} hydrocarbons, miscibility with oils occurs. Therefore, the MMP is strongly related to the average molecular weight of the C_{5+} components of the oil and the oil gravity, as well as the reservoir temperature. [100] [116] The relationship of these variables and the MMP to CO_2 is highlighted in Equation 4-1 and Equation 4-2. Accordingly, heavier oils require much higher pressures to become miscible (Exhibit 4-3). [30] [99] Additional factors that have been cited that impact MMP include the volatile fraction of the oil (CH_4 and nitrogen [N_2]) and the intermediate component fraction of oil (CO_2, hydrogen sulfide [H_2S], and C_2-C_6 hydrocarbons). As reference, several of the MMP empirical correlation approaches developed do account for the volatile fraction and intermediate oil component fractions (including Alston et al. [1985], [114] Emera and Sarma [2005], [117] and Liao et al. [2014], [118]). MMP has been shown to generally decrease when the oil fraction favors the intermediate components to volatile components; on the other hand, MMP increases when the volatile component oil fraction is greater than the intermediate component fraction. [115] [119] The MMP estimation approach outlined in Equation 4-1 and Equation 4-2 is simplified and does not directly account for oil intermediate and volatile fractions but is effective for MMP screening when data sets pertaining to reservoir and oil properties (especially oil compositional data) is limited or not available.

There are two prominent types of miscible mechanisms between CO_2 and oil: (1) first contact and (2) multi-contact. [30] [102] These mechanisms are explained briefly in the bullets below to provide background on the CO_2 and oil interactions in the subsurface:

- First-contact miscible solvents blend with reservoir oil in all proportions, and the mixture remains in one phase when first brought into contact at a given pressure and temperature. Under reservoir gas floods, the injected gas composition, oil composition, temperature, and the injection pressure determine the condition of first-contact miscibility. [120] Often, CO_2 is not miscible on the first contact, but can develop miscibility on multiple contacts, known as dynamic miscibility, resulting in much higher oil recovery.
- Multi-contact miscible is a dynamic fluid mixing process where injected gas exchanges components with in situ oil until the phases achieve a state of miscibility within the mixing zone of the flood front. In a vaporizing drive, volatile and intermediate components (discussed in the preceding paragraphs) from the oil phase enter the gas phase. In contrast, under a condensing drive, intermediate components from the gas phase enter the oil phase. Depending on reservoir conditions, the process may be a combination of both vaporizing and condensing drives. [121] For instance, the injected CO_2 first condenses into the oil, then makes it lighter and drives methane out ahead of the "oil bank." Then the oil's volatile components vaporize into the CO_2-rich phase and make it denser like the oil, thus it becomes more soluble in the oil. Mass transfer continues between the CO_2 and oil until two mixtures hold the same fluid properties. [105] At high pressures, CO_2 becomes miscible with the oil through a multiple-contact process in which mass transfers continue between the CO_2 and oil phases until they become a single phase. This mass transfer between the oil and CO_2 allows the two phases to become completely miscible without any interface and helps to develop a transition zone that is miscible with oil in the front with CO_2 in the back. [30] [105]

When the reservoir pressure is below the MMP, CO_2 can only dissolve in the oil, swelling the oil and reducing its viscosity, which leads to smaller volumes of the residual oil to become mobile and recovered relative to miscible conditions (hence the importance of attaining miscibility). [122] The CO_2 and the oil will not form into a single phase. These conditions would result in what is known as an "immiscible flood." CO_2 solubility in oil increases with pressure and decreases with increasing temperature. [30] If oil saturations in the reservoir prior to CO_2 flooding are at the residual saturation to water, the swelling caused by CO_2 can increase the overall oil saturation within the formation. Under these circumstances, subsequent displacement by water can then be used to mobilize the additional oil in the reservoir.

4.1.2 Porosity

Porosity is a measure of the formation void space and indicates the ability of rock to store fluids. It is expressed as a percentage and is defined as the pore volume divided by the bulk volume as shown in Equation 4-3 below:

$$\phi = \left(\frac{V_p}{V_b} \right)$$ *Equation 4-3*

Where:

V_p = pore volume (volume)
V_b = bulk volume (volume)
$\emptyset$ = porosity (decimal)

A distinction must be made between the effective and total porosity within the system. The total porosity accounts for all the pore spaces within a given unit. The effective porosity accounts for the interconnected pores within the system. The effective porosity will be less than or equal to the total porosity depending on the type of reservoir and number of isolated pores within the system. [123]

The fluids that are present within the available porosity of a reservoir are also of importance when screening for CO_2 EOR potential. Fluid saturations within the reservoir are based on the type and amount of fluid in the system, which may include water, gas, or hydrocarbons. Any given fluid saturation volume is represented using Equation 4-4:

$$S_f = \frac{V_f}{V_p}$$ *Equation 4-4*

Where:

S_f = fluid saturation (decimal)
V_f = volume of fluid (volume)
V_p = pore volume (volume)

The saturation distribution for each fluid may change over the course of a water or CO_2 flood, but the sum of their contribution to the total fluid saturation should be 1 as expressed in Equation 4-5.

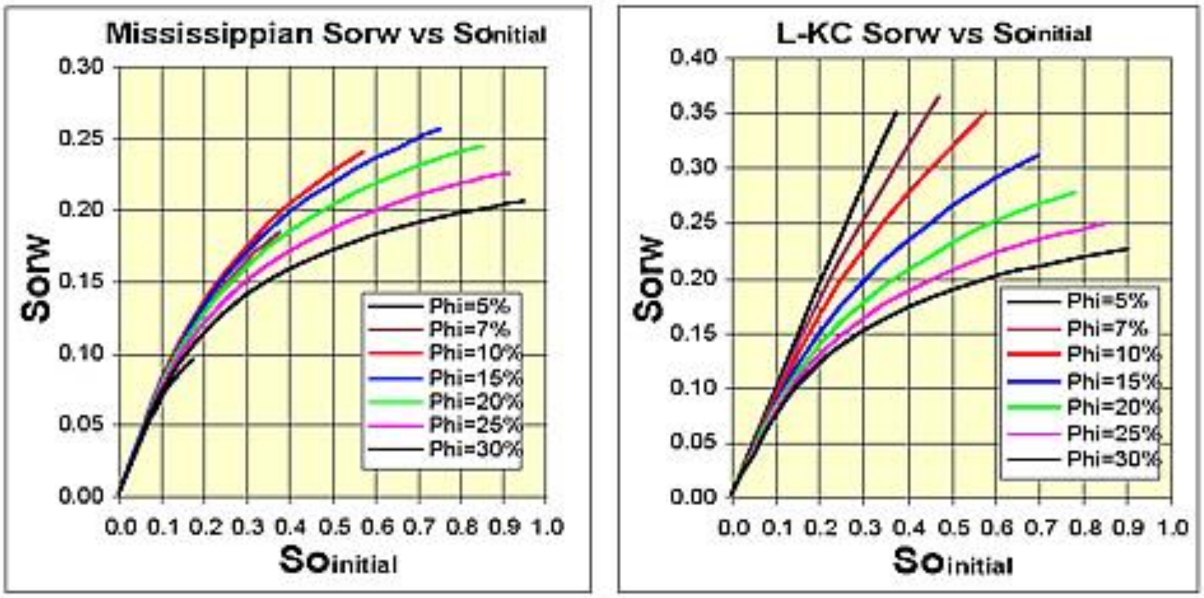
$$1 = S_w + S_o + S_g$$ *Equation 4-5*

Where:

S_w = water saturation (decimal)
S_o = oil saturation (decimal)
S_g = gas saturation (decimal)

Porosity and fluid saturation are important towards understanding the potential overall performance of flooding (either water or CO_2) and could allude to the amount of residual oil in place before CO_2 flooding begins. For instance, the effective porosity of the reservoir has been shown to have an impact on the expected recovery of oil prior to a waterflood, as well as the resulting remaining residual oil left after a waterflood (Exhibit 4-4).

Exhibit 4-4. Change in the residual oil saturation to a waterflood (S_{orw}) as a function of initial oil saturation ($S_{oinitial}$) and sample porosity for Mississippian and Lansing-Kansas City group limestones. [124]



NETL supported a project led by the Kansas Geological Survey (DE-FE-FC26-04NT15516) that developed models for oil-water relative permeability from formations prominent in the U.S. mid-continent. [124] Drainage and imbibition oil-water relative permeability measurements taken as part of the study suggested that residual oil saturation to waterflood (defined in this project as S_{orw}) would increase with increasing initial oil saturation (defined in this project as $S_{oinitial}$) for the given rock type studied. This was interpreted to be due to enhanced trapping by emplacement of oil in fine pores. Additionally, Exhibit 4-4 highlights that increasing porosity values (defined in this project as Phi) show a relative reduction in the residual oil after waterflooding. Based on this data, the formation porosity and initial oil saturation values could allude to the expected remaining oil in place after secondary (waterflood) recovery for future projects. [124]

Both sweep efficiency and microscopic displacement (oil displacement from the pore space) efficiency are highly dependent on the reservoir's porosity, and the ability of the injected (CO_2) gas to contact the oil in each individual pore. [125] The optimum porosity for this to occur has been reported near 20 percent. [104] Additionally, mineralization that may result from the injection of CO_2 leads to an overall decrease in porosity, particularly in sandstone reservoirs. [126]

Lastly, the integration of known porosity data, initial fluid saturation data, and other reservoir-related data (like areal extent and net reservoir pay zone thickness) can be used to infer the amount of oil and gas in place. A general formula for the calculation of the volume of hydrocarbons (oil and gas) in a reservoir, often referred to as hydrocarbon pore volumes (HCPV), is represented in Equation 4-6 as follows: [127]

$$HCPV = Ah\emptyset(1 - S_w) \qquad \textit{Equation 4-6}$$

Where:

HCPV	= hydrocarbon pore volumes (volume dependent on units used for area and thickness)
A	= reservoir areal extent (area; ft^2 or acres) [i]
h	= reservoir net pay thickness (ft)
Ø	= porosity (decimal)
S_w	= initial water saturation prior to production (decimal)

Estimating HCPV effectively is reliant on accurate data. In Equation 4-6, the impact of values like porosity, area, and thickness on total HCPV is evident; therefore, inaccurate data could lead to underestimation or overestimation of the HCPV in the reservoir. Since oil fields are typically variable in size, shape, and injection design, HCPV is often used as a relative way to compare injection and production from one field to another. Underestimation of HCPV may influence operators to not pursue a candidate CO_2 EOR reservoir; and an overestimation could lead to a substantial economic loss if the projected oil/gas reserves are lower than expected. Other geologic and reservoir factors (such as permeability barriers and faults) and CO_2 EOR injection design factors (like well placement and different flooding strategies) are also factors that can influence reservoir performance. [127]

4.1.3 Permeability

Permeability pertains to the quality of reservoir rock that enables it to allow liquids or gases to pass through it when a pressure gradient is applied. It is mainly influenced by how well the reservoir rock's internal porosity is connected. [2] [125] Permeability is often expressed in Darcy, or mD, as well as square meter (m^2). For CO_2 EOR applications, field experience has indicated that reservoir permeability is recommended to be at least greater than 5 mD (0.005 Darcy) (Exhibit 4-1). [43] Typically, rocks that have a higher permeability enable greater fluid flow rates through the reservoir; however, extensively high-permeability channels, such as faults and fractures, inhibit overall sweep efficiency and CO_2 flood conformance. The majority of oil reservoirs that are candidates for CO_2 EOR have already undergone successful production (oil and water) and injection (water) from primary and secondary production operations, and therefore, likely have sufficient permeability for CO_2 flooding. [100] Permeability is often referred to in relative contexts, for instance: 1) absolute; 2) effective; and 3) relative. Absolute permeability is essentially the permeability of a porous medium that is saturated with a single fluid. Effective permeability is the permeability of a given fluid phase when more than one phase is present in the rock, for example, in a reservoir with both oil and water, or CO_2. Effective permeability is also expressed in Darcy, mD, or m^2. When the effective permeability (for a fluid) is divided by the absolute permeability, it is termed relative permeability, and is dimensionless. [128]

Injectivity tests, also called pressure fall-off tests, can be analyzed to assess an injection zone of the CO_2 EOR reservoir of interest for effective permeability. [129] In this type of test, a fluid (e.g., water) is pumped into a well at a constant rate until pressure stabilizes; at that point, the

[i] There are 43,560 ft^2 per acre.

pumping ceases and the rate at which pressure decreases is measured. The pressure measurements can be graphed and effective permeability to water within the reservoir (which likely contains oil and gas saturations) can be calculated. An injectivity test as described will provide an indication of well performance and subsurface response expected from a given rate of injection.

Effective permeability influences fluid flow as highlighted in Equation 4-7 (i.e., variation of the Darcy equation), which is specific for steady-state gas flow in a laterally unconfined, homogenous, saline reservoir. [130]

$$Q = \frac{0.703\mathrm{kh}\left(\mathrm{P_i^2} - \mathrm{P_f^2}\right)^n}{\mathrm{T}\mu Z\left(\ln\left(\frac{\mathrm{r_e}}{\mathrm{r_w}}\right)\right)}$$ *Equation 4-7*

Where:

Q	= the volumetric gas flow rate through the medium (Mscf/d)
h	= reservoir thickness (ft)
k	= the effective permeability of CO_2 in the reservoir (mD)
P_i	= injection pressure (psia)
P_f	= initial formation pressure (psia)
T	= current reservoir temperature (°R)
μ	= gas viscosity at reservoir conditions (cP)
Z	= gas deviation factor (dimensionless)
r_e	= radius of external drainage boundary (ft)
r_w	= radius of the wellbore (ft)
n	= numerical constant that typically varies between 0.5 (under high turbulence) and 1.0 (no turbulence) [131]

In addition to understanding the concepts of absolute and effective permeability, proper understanding of the relative permeability of subsurface systems is essential in determining CO_2 injectivity, multi-phase migration, and suitability of potential CO_2 EOR sites. [132] Relative permeability is a dimensionless term based on an adaptation of the Darcy equation (i.e., Equation 4-7) specific for multiphase flow conditions. It is the ratio of the effective permeability of an individual fluid at a given saturation to the absolute permeability of the reservoir rock.[j] Calculation of relative permeability enables comparison of different fluids to flow in the presence of each other, given that the presence of multiple fluid types (in the case of CO_2 EOR, this could include oil, brine, and CO_2) inhibits the flow of the other fluids present. [105] [133]

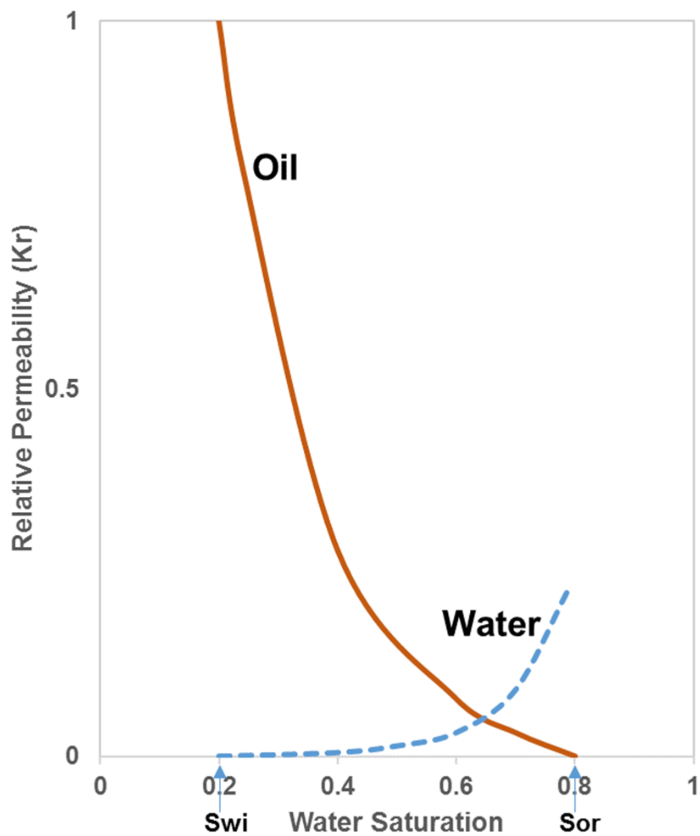
Common industry understanding is that water injectivity undergoes significant changes after the first cycle of a CO_2 flood, due to the effect of trapped CO_2 on water's relative permeability. The effect of three-phase relative permeability in an oil-water-CO_2 system can reduce the mobility of both CO_2 and water. Therefore, quantifying the water mobility and subsequent effects on field

[j] The presence of just a single fluid in given type of rock would result in a relative permeability of 1.0. [133]

operation are necessary for meaningful simulation of a CO_2 flood to determine significant considerations like the economic payout period of the project. Additionally, the variation in CO_2 relative permeability over the life of a CO_2 flood affects the propagation of CO_2 throughout the reservoir, which directly impacts CO_2 production rates, as well as the operating and capital costs of a given CO_2 EOR project.

To better understand the relative permeability concept, an example is presented in Exhibit 4-5 for oil and water (or brine). Oil-relative permeabilities tend to decline over a given field's productive life as water takes a larger portion of the pore volume (say in a waterflood), and further restricting the flow of the oil. [105] Exhibit 4-5 specifically shows the two-phase relative permeability (K_r) for oil and water as a function of increasing water saturation in the pore volume. The relative permeability of oil, which is 1.0 at connate water saturation, declines as oil is produced and more water is injected, while the water relative permeability value increases.

Exhibit 4-5. Conceptual representation of a relative permeability curve for oil and water between the initial water saturation (S_{wi}) and residual oil saturation (S_{or}) points in a strongly water-wet rock reservoir



Under miscible flooding conditions, when oil and CO_2 are completely miscible, they should act as a single fluid. In this case, the miscible mixture would have a relative permeability function. Given that not all the CO_2 will contact and become miscible with oil, the relative permeabilities for oil and CO_2 will also depend on the degree of miscibility in the system.

Determining relative permeability values for predictive modeling applications for CO_2 EOR (as well as CO_2 storage) is a non-trivial task. Theoretical models and laboratory experiments have been noted as ways to assess relative permeability for subsurface systems in the presence of CO_2. However, there are noted uncertainties in both approaches to effectively account for reservoir conditions and rock heterogeneity. Furthermore, the low viscosity of CO_2 in comparison to other formation fluids can result in a system where the influence of capillary forces may outweigh the influence of viscous forces, making laboratory experiments challenging and the system relatively sensitive to fluid properties. [134] Regardless, relative permeability is important to understand for CO_2 EOR applications because they are significantly tied to the mobility ratio, and therefore recovery efficiency of CO_2 EOR systems. [125] The mobility ratio is a fraction that compares the ability of a solvent to flow through porous media relative to the fluid that it is intended to displace. The mobility ratio for CO_2 and oil can be expressed as follows in Equation 4-8: [135]

$$M = \frac{k_{rCO2}/\mu_{CO2}}{k_{roil}/\mu_{oil}} \qquad \textit{Equation 4-8}$$

Where:

- M = mobility ratio (dimensionless)
- μ_{CO2} = the viscosity of CO_2, which is the displacing fluid (cP)
- k_{rCO2} = the relative permeability of the porous media to the displacing CO_2 as a function of the saturation of that displacing phase (decimal)
- μ_{oil} = the viscosity of the oil phase being displaced (cP)
- k_{roil} = the relative permeability of the porous medium to the oil phase as a function of oil saturation (decimal)

Because the viscosity of dense CO_2 (typical CO_2 flooding condition is ~ 0.05–0.10 cP) is substantially lower than that of the oil (2–15 cP per Exhibit 4-1), the mobility ratio for a CO_2 flood is often much greater than 1. When $M > 1$, sweep efficiency will be reduced, even in homogenous reservoirs. [125] Typically, the ratio of oil viscosity to water viscosity is around 2, while the ratio of oil viscosity to CO_2 viscosity is an order of magnitude larger. [30] This unfavorable mobility ratio can result in viscous fingering of the CO_2 and the associated problems, like early CO_2 breakthrough, high CO_2 utilization ratios, delayed CO_2 production, depressed oil production rates, and an overall low percent of OOIP recovery. [135] As a result, mobility and flood conformance are issues considered to be some of the most crucial concerns associated with CO_2 flooding. Mobility control has been most readily accomplished with the injection of both CO_2 and water into the formation, usually in an alternating sequence (WAG) that promotes near-wellbore injectivity and diminishes mobility away from the wellbore. Additionally, polymers and other chemical additives have been explored to increase the viscosity of injected fluids to improve mobility control. [30] [135] [136]

While the properties that influence the relative permeability and viscosity of CO_2 and oil are critical to mobility, overall flood sweep efficiency is also highly affected by the geological heterogeneity in the reservoir, which directly impacts reservoir permeability and porosity spatial distributions. For instance, channeling caused by reservoir heterogeneity is believed to more strongly impact sweep efficiency than viscous fingering effects. [125] Based on Equation

4-8, the effects of heterogeneity are intensified when the fluid injected has a lower viscosity than the oil, like supercritical CO_2. Large-scale heterogeneities within the reservoir may channel the injected CO_2, which can reduce the overall sweep. Similar mobility control techniques discussed in the paragraph above can also be used to reduce the mobility ratio, as well as channeling effects, from highly heterogenous reservoir.

Another important consideration is the lithology of the producing reservoir. While it does not specifically influence CO_2 EOR operations, the reaction of CO_2 with carbonates, like dolostone and limestone, can result in a higher permeability through dissolution processes. [30] On the other hand, if the rock types within the reservoir promote precipitation of minerals in the presence of CO_2, reductions in permeability may occur. [137] Therefore, characterizing the reservoir fluid geochemistry is important for understanding the potential impact of CO_2 in the system.

4.1.4 Residual Oil Saturation

After primary and secondary production has been completed, residual oil is still left behind in the reservoir either due to poor waterflood sweep efficiency or entrapment by viscous, capillary, and interfacial tension forces within the pore space. [101] A successful CO_2 EOR operation could remove an additional 5–15 percent of the OOIP. [30] Insight into the amount of residual oil in place after waterflooding is required to assess the technical feasibility and profitability of a potential CO_2 EOR project. [1] Shaw and Bachu (2002) [100] have indicated that the residual oil saturation to a waterflood must be typically greater than 0.25 for profitable EOR operations. Exhibit 4-1 above provides a range for oil saturations (post-waterflood) for successful CO_2 EOR projects. [43] [99] [100]

The residual oil left after secondary production (i.e., waterflooding) will ultimately influence the technically recoverable volumes of oil from a CO_2 EOR operation. Combining known parameters associated with a given reservoir's areal extent, net pay zone thickness, porosity, OOIP, and cumulative historical production can provide inference about the residual oil in place following a waterflood (S_{orw}). [138] Equation 4-9 below outlines the relationship of those field and production parameters for an approach to estimate S_{orw}.

$$S_{orw} = 0.00129\left(\frac{OOIP - P_{oic}}{Ah\emptyset}\right)B_{oi}$$ *Equation 4-9*

Where:[k]

- OOIP = reservoir's original oil in place prior to production (barrels)
- P_{oic} = reservoir's historic cumulative oil production through waterflooding (barrels)
- A = reservoir areal extent (acres)
- h = reservoir net pay thickness (ft)
- $\emptyset$ = porosity (decimal)
- B_{oi} = oil formation volume factor at initial reservoir pressure (decimal –

[k] The constants used in Equation 4-9 (1/7,758; or 0.00129) and Equation **4**-**10** (7,758) are multiplication factors pertaining to barrels/acre-feet for conversion of reservoir area in the unit of acres.

reservoir barrel/stock tank barrel)

Equation 4-10 below presented by Verma (2015) [30] can be used to calculate the value of OOIP volumetrically which is used above in Equation 4-9. OOIP differs from HCPV in that it only accounts for oil, not total hydrocarbons.

$$OOIP = 7{,}758\,\frac{(Ah\emptyset S_{oi})}{B_{oi}} \qquad \textit{Equation 4-10}$$

Where:[k]

A	= reservoir areal extent (acres)
h	= reservoir net pay thickness (ft)
Ø	= porosity (decimal)
S_{oi}	= initial oil saturation prior to production (decimal)
B_{oi}	= oil formation volume factor at initial reservoir pressure (decimal – reservoir barrel/stock tank barrel)

Data pertaining to the reservoir's OOIP and cumulative production should be readily known from early field prospecting and characterization prior to primary production, and from tracking oil production values over time respectively. However, for the development of Greenfield sites for CO_2 EOR (like ROZs), operators may likely have to rely on new reservoir characterization data to understand residual oil saturation values, as well as other reservoir characteristics pertaining to net pay thickness, porosity, and areal extent.

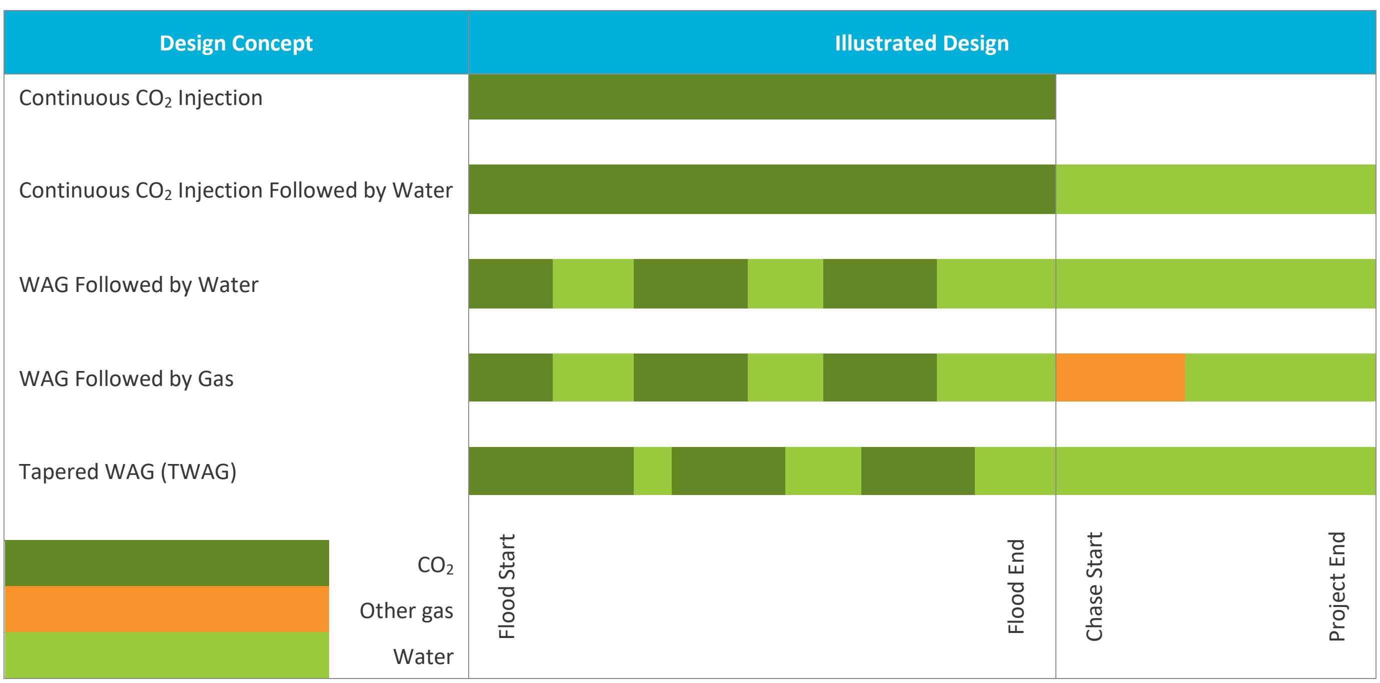
4.2 CO_2 EOR Injection Design

After reservoir screening is completed, a pattern of production and injection wells need to be chosen by the operator; one that ensures optimal oil recovery. Large-scale reservoir heterogeneity (substantial changes in permeability with respect to the location within the reservoir) is a principal factor that can influence the success or failure of a CO_2 flood. As mentioned in Section 4.1.3, reservoir heterogeneity affects the sweep efficiency in a CO_2 flood more so than it does in a waterflood, because CO_2 is more mobile than water and can cycle through high-permeability channels more easily than water. A widely-used approach to improve sweep in a CO_2 EOR operation is the use of WAG injection at a fixed injection ratio. Alternating water injection improves sweep efficiency by temporarily decreasing the gas mobility (by increasing the water saturation and decreasing the relative permeability to gas). When WAG fails to control the sweep, other techniques including surfactant foams, gel polymers, and conventional plugging methods can be used. Gravity can help oil recovery by improving sweep in dipping reservoirs by eliminating the need to use water injection for mobility control. [135] [139] On the other hand, gravity can be negatively impactful in CO_2 EOR development due to the density difference between oil and CO_2. For instance, in reservoirs where vertical permeability is high, CO_2 overrides oil and can create "gravity tongues" given that CO_2 is less dense than the oil. Under these circumstances, CO_2 tends to flow toward the top portion of thick, high permeability zones, and injected water tends to flow toward the lower portion of the zone impacting overall mobility control. Water is normally injected to increase the sweep efficiency, but in these types of cases, injecting water may likely reduce vertical sweep since it is not contacting the same reservoir portion as the oil. [105] For reference, a summary of parameters influencing the effectiveness of sweep efficiency and the impact on a potential CO_2 EOR flood is presented in Appendix E: Importance of Sweep and Displacement Efficiency on a Potential CO2 EOR Projects.

When the ratio of average vertical to horizontal permeability is greater than 0.05, a reservoir is considered to have strong vertical permeability, in which the effects described in the paragraph above could occur. [140] Vertical permeability can be measured in the field using pressure transient tests and repeat formation testing, but these are sensitive to even minor formation fracturing or cracks in a well cementing job. Core data is a reliable method to estimate vertical permeability. Shale layers interbedded within the target reservoir would add to overall reservoir heterogeneity, but also contribute towards reducing the effective vertical permeability. [141] Some reservoirs, such as carbonate reservoirs in the Permian basin, were deposited in a low-energy environment that resulted in low vertical permeability layers.

A variety of CO_2 EOR injection designs may be deployed depending on the reservoir geology and fluid properties. As indicated in the preceding paragraphs, the design for optimal recovery efficiency of the flooding process is strongly dependent on the reservoir geology, as well as fluid and rock properties, existing fluid saturation distributions, and well-pattern configuration. [30] Potential approaches that have been widely-used in CO_2 EOR applications are described below and depicted visually in Exhibit 4-6.

Exhibit 4-6: Conceptual CO_2 flood injection designs [30] [105]



A description of each of the flooding design concepts presented in Exhibit 4-6 is summarized in the bullets below:

- Continuous CO_2 injection: A predetermined volume of CO_2 is injected with no other fluids
- Continuous CO_2 injection followed by water: A predetermined volume of CO_2 is injected followed by injection of water
- WAG followed by water: A predetermined volume of CO_2 and water is injected in alternating cycles. The process is followed by the injection of water to sweep any remaining miscible CO_2/oil mixture from the pore space and replace it with less expensive water
- WAG followed by gas: A predetermined volume of CO_2 and water is injected in alternating cycles. The process is followed by the injection of a less expensive gas after the full CO_2 volume has been injected
- Tapered WAG (TWAG): CO_2 gas and water are injected in alternating cycles, with a gradual decrease in the volume of CO_2

Continuous injection of CO_2 is typically used in reservoirs that are sensitive to waterflooding or that are water-wet, while continuous CO_2 injection followed by water is used in reservoirs with low permeability or relatively homogenous permeabilities. [30] The WAG process was developed to reduce the volume of gas (CO_2) needed to maintain reservoir pressure. The process also helps overcome the CO_2 override and reduce CO_2 channeling—increasing the CO_2 EOR efficiency in reservoirs with permeability contrasts. [30] While vertical sweep efficiency improves with the traditional WAG process, early CO_2 breakthrough may still occur. [32] However, the WAG technique is one of the most successful EOR flooding approaches used today. TWAG is similar to conventional WAG but involves gradual reduction in the volume of injected CO_2 relative to the injected water volume. TWAG prevents early breakthrough of CO_2, ultimately requiring less CO_2 recycle (potentially saving on facility costs). [30]

Also, of critical importance to the injection design is the injection and production well pattern. A widely-used pattern is the normal 5-spot pattern.[l] Other well patterns may include 4-, 7-, and 9-spot patterns, all with a single production well surrounded by different numbers of injection wells. Additionally, line drive configurations can be used in which, the injection wells are in a straight-line parallel to the production wells. [142] This type of pattern can be used if the reservoir permeability distribution and other geologic parameters support the configuration. Ultimately, the selection of pattern is based on the reservoir and fluid properties associated with the field, as well as on the reservoir's anticipated response to fluid injection. Reservoir simulation is performed to develop an optimized well pattern configuration and flooding approach that has the highest probability to maximize oil production and CO_2 utilization. [30]

[l] A 5-spot well pattern includes four injection wells position at the corners of a square-like configuration, with a production well at the center. Injected fluids (water, CO_2, steam, etc.) is injected through the four injection wells concurrently to displace the oil toward the central production well. [290] Well spacing may also take on 7- or 9-spot.

4.3 Technical and Economic Screening Factors and Considerations for CO_2 EOR

The fundamental challenge current CO_2 EOR operators must overcome and understand before initiating a project is how much incremental oil can be economically recovered. [36] To derive and answer to this challenge, it is important to consider the reservoir properties (described throughout Section 4.1), flood performance, operation costs, and estimated economics of the project.

Once a candidate CO_2 EOR reservoir meets the higher-level screening requirements outlined in Section 4.1, pilot testing on a small-scale could be performed to determine the likelihood of successful CO_2 EOR in the reservoir. Additionally, if existing data sets are sufficiently comprehensive, reservoir simulation could be carried out to estimate scaled-up CO_2 EOR operations across an entire oil field, which would help towards defining the optimum design flood type and HCPV injection volumes for maximum oil recovery. [30]

4.3.1 Prediction of CO_2 Flood Performance

The main purpose of conducting CO_2 flooding performance prediction is to estimate the oil-recovery efficiency and the volume of CO_2 utilized across possible operating scenarios. The recovery efficiency of the CO_2 flood is controlled by several factors including the mobility ratio (the ratio of the mobility of the displacing fluid divided by the mobility of the displaced fluid as outlined in Equation 4-8), gravity segregation between the phases with density differences, and by overall reservoir heterogeneity. [100] Scaling up CO_2 flood performance is commonly used as a cursory prediction method of an entire field. Current methods for analyzing reservoir performance include extensive numerical modeling based on detailed knowledge of the oil reservoir, streamtube models, as well as scaled physical models, and simulation. The later approach involves taking CO_2 flood performance from a similar reservoir as an analog and multiplying the performance by scaling variables. The analog reservoir, for instance, could be another reservoir under CO_2 flood with comparable properties as the reservoir of interest, or a pilot CO_2 flood results within in the reservoir of interest.

The reservoir simulation process, regardless of the specific approach utilized as described in the preceding paragraph, typically involves three main steps per Verma (2015) [30]:

1. Data input and initialization, where all the reservoir parameter inputs are collected and compiled for integration into the simulator. They are considered accurate and realistically represent the reservoir.
2. History-matching, where simulation results are compared with the historical production and pressure data for fields in question. The values of sensitive parameters can be adjusted to achieve the best-fit matches between the simulation results and historical injection, production, and pressure data.
3. Forecast, which includes running several scenarios of various injection designs, WAG ratios, and total HCPV injections to determine the optimum design of the CO_2 EOR flood that maximizes oil recovery (and does so the most cost-effectively).

Once the history matching step is completed, simulation can be used determine the optimum CO_2 injection scheme, forecast oil production, as well as estimate the volume of other fluids expected to be produced. The supporting site infrastructure needs and potential equipment sizing requirements (like the CO_2 recycle plant) can be inferred and utilized in a design based around maximizing the net-present value (NPV) over the duration of a planned flood. For example, a scenario described by Pariani et al. (1992) [143] suggested that initiating a CO_2 pattern flood with a low water to CO_2 ratio, and then increasing that ratio over time can improve both incremental oil recovery and overall cost effectiveness. The increasing ratio can improve sweep and helps slow CO_2 production and prevents it from exceeding the capacity of the CO_2 processing and recycle plant. Other approach scenarios (like those outlined in Exhibit 4-6) can be modeled as well in pursuit of the most profitable option based on the reservoir's/field's specific characteristics.

A specific and high-level analytical approach for estimating CO_2 flooding performance was presented by Shaw and Bachu (2002) [100] and is summarized below. Their approach was developed and implemented based on previous work conducted by Koval (1963), [144] Claridge (1972), [145] and Hawthorn (1960) [146] to account for both areal sweep, gravity-stabilization effects, and trapped-oil saturation. Bachu and Shaw indicate that this approach is suitable and can be applied for oil reservoir cases with limited information about each, such as government reserves databases as a source. The approach specifically calculates oil recovery for a series of assumed CO_2 and water slug sizes (in terms of HCPV) in a 5-spot WAG miscible flood. The method assumes the oil reservoir has no aquifer support, and could result in an overestimation of both oil production and CO_2 storage (only the oil production approach is presented in the equations below); [100] The following equation (Equation 4-11) is the Shaw and Bachu approach for estimating the fraction of oil produced from the miscible injection:

$$\left(\frac{N_P - V_{piBT}}{1 - N_P}\right) = \left(\frac{1.6}{K^{0.61}}\right)\left(\frac{F_i - V_{piBT}}{1 - V_{piBT}}\right)^{\left(\frac{1.28}{K^{0.26}}\right)}$$

Equation 4-11

Where:

- N_p = fraction of volume of oil produced from miscible flooding (volume/volume)
- V_{piBT} = fraction of pore volume of injected solvent (i.e., CO_2) at breakthrough (volume/volume)
- F_i = fraction of HCPV of solvent injected in a reservoir in a 5-spot pattern (volume/volume)
- K = Koval factor (decimal - defined below)

The actual fraction of pore volume of solvent injected at breakthrough (V_{piBT}) is based on the following equations:

$$V_{piBT} = E_{ABT} \times V_{pvdBT}$$

Equation 4-12

and

$$E_{ABT} = 1 + \frac{0.4M}{1+M}$$ *Equation 4-13*

and

$$V_{pvdBT} = \frac{1}{K}$$ *Equation 4-14*

Where:

V_{piBT}	= fraction of pore volume of solvent injected at breakthrough (volume/volume)
E_{ABT}	= areal sweep efficiency at breakthrough (decimal)
V_{pvdBT}	= invaded pore volume injected at breakthrough (decimal)
M	= mobility ratio (Equation 4-8); ratio of oil viscosity to solvent (CO_2) viscosity (fraction)
K	= Koval factor (decimal - defined in the equation below)

The Koval factor (K) presented as a variable in Equation 4-11 above is defined by the set of equations listed below. The Koval factor is 1 for cases with a homogeneous reservoir with oil and solvent (CO_2) of the same density and viscosity. For all other cases, which are more likely expected, K is greater than 1:

$$K = H \times F \times \left[0.78 + 0.22M^{1/4}\right]^4$$ *Equation 4-15*

and

$$log_{10}H = \left[\frac{V_{DP}}{(1-V_{DP})^{0.2}}\right]$$ *Equation 4-16*

and

$$F = 0.565log_{10}\left[Ck_VA\frac{\Delta\rho}{Q\mu_{CO2}}\right] + 0.87$$ *Equation 4-17*

Where:

K	= Koval factor
H	= reservoir heterogeneity factor (decimal - typically 1 for homogenous reservoirs)
F	= gravity override factor (decimal - 1 if no gravity is assumed)
M	= mobility ratio (Equation 4-8); ratio of oil viscosity to solvent (CO_2) viscosity (fraction)
V_{DP}	= Dykstra-Parsons coefficient of reservoir heterogeneity (decimal – typically 0.5 to 0.9 with an average around 0.7) [100] [147]
k_v	= vertical permeability (mD)
A	= pattern areal size (acres)
$\Delta\rho$	= density differential between oil and CO_2 (grams/cm^3)
Q	= injection rate (reservoir bbl/day)

μ_{CO2} = solvent (CO_2) viscosity (cP)
C = flood pattern constant (2.5271 for 5-spot, and 2.1257 for line drive)

As mentioned above, this type of approach presented by Shaw and Bachu provides a preliminary prediction of incremental oil production volumes based on the different HCPV of injected CO_2 when using constrained sets of reservoirs data. However, an approach like this enables the screening of potential reservoirs, which can help identify the most suitable for CO_2 flooding, prior to detailed and specific reservoir studies. [100] Overall, the approach developed by Shaw and Bachu emphasizes the importance of key parameters discussed in previous subsections within Section 4 on CO_2 EOR performance. For instance, it is evident from the equations above of the importance of attaining sufficient data for parameters like HCPV, reservoir net pay thickness, permeability, CO_2 and oil viscosities, reservoir areal extent, and insight on the extent of heterogeneity within the target reservoir in order to accurately infer about CO_2 EOR flood performance.

4.3.2 Scoping Economics

The next step in the technical screening process is to estimate the capital investment and incremental operating costs of processing the predicted incremental production rates based on reservoir simulation. Implementing a CO_2 EOR project is a capital-intensive undertaking that involves drilling new wells or reworking existing wells to serve as injectors or producers, installing a CO_2 recycle plant and corrosion resistant field production infrastructure, and laying CO_2 gathering and transportation pipelines. Generally, the single largest project cost is the purchase of CO_2, so operators strive to optimize the flood and reduce the demand for CO_2 injection wherever possible. [2]

After the CO_2 flood has been scoped to predict performance and operating cost, an assessment of the flood's potential economic feasibility can be determined. Only floods that would be deemed economically viable and profitable would progress towards field implementation. Detailed CO_2 project evaluation should proceed only after scoping economics indicate that CO_2 flooding maybe acceptable and profitable under a practical operating scenario—circumstances that are strongly driven by the expected price of oil. The economic parameters to consider are cumulative incremental cash flow and ratio of NPV to investment.

Oil prices significantly impact the economics of CO_2 EOR. In 2017, oil prices ranged between $42 to $54 per barrel—a dramatic reduction from a peak price of around $145 per barrel in 2008. [148] However, worth noting, oil field costs have decreased recently, [149] which improves the economic margin essential for justifying CO_2 EOR projects. [2] Both capital and operating costs for an EOR project can vary over a range, including the commodity price of CO_2. CO_2 is priced at pressure, pipeline quality, and accessibility, but tied to the price of oil. In addition to the high up-front capital costs of CO_2 supply/injection/recycling, there is a significant delay between the start of CO_2 injection/purchase and the onset of incremental oil production. Hence, the return on investment for CO_2 EOR tends to be low, with a gradual, long-term payout. Oil reservoirs with higher capital costs or a higher CO_2 utilization factor (i.e., volume of CO_2 injected per barrel of oil produced) may not achieve an economically justifiable return on investment without fiscal/tax incentives for storing CO_2. [2]

4.3.3 Well Design

Well design considerations for injection and production wells in a CO_2 EOR project share challenges expected for commercial-scale CO_2 storage in saline-bearing formations. Metallurgy, valve types, pressure ratings, and elastomers and seals in production and injection wells must all be compatible with a CO_2 flood. Changes from the secondary (waterflooding) to tertiary (CO_2 flooding and WAG) forces operators to modify wellhead equipment accordingly. In recent years, operators tend to make few or no upfront changes to wellhead components unless on an as-needed basis. [150] However, corrosion related to the presence of CO_2 and water, increased operating pressures, high salinity, and altered oil composition, can affect carbon steel wellhead components, and possibly cement, and therefore must be considered when evaluating well design and technology selection.

Proper cementation of the well bore is critical to the mechanical integrity of a well. The cement anchors the casing to the formation providing structural stability and providing a seal between the casing and the surrounding formation. In existing oilfields where re-completion of existing wellbores can occur, several best practices have been documented and are typically used as standard practice: [1]

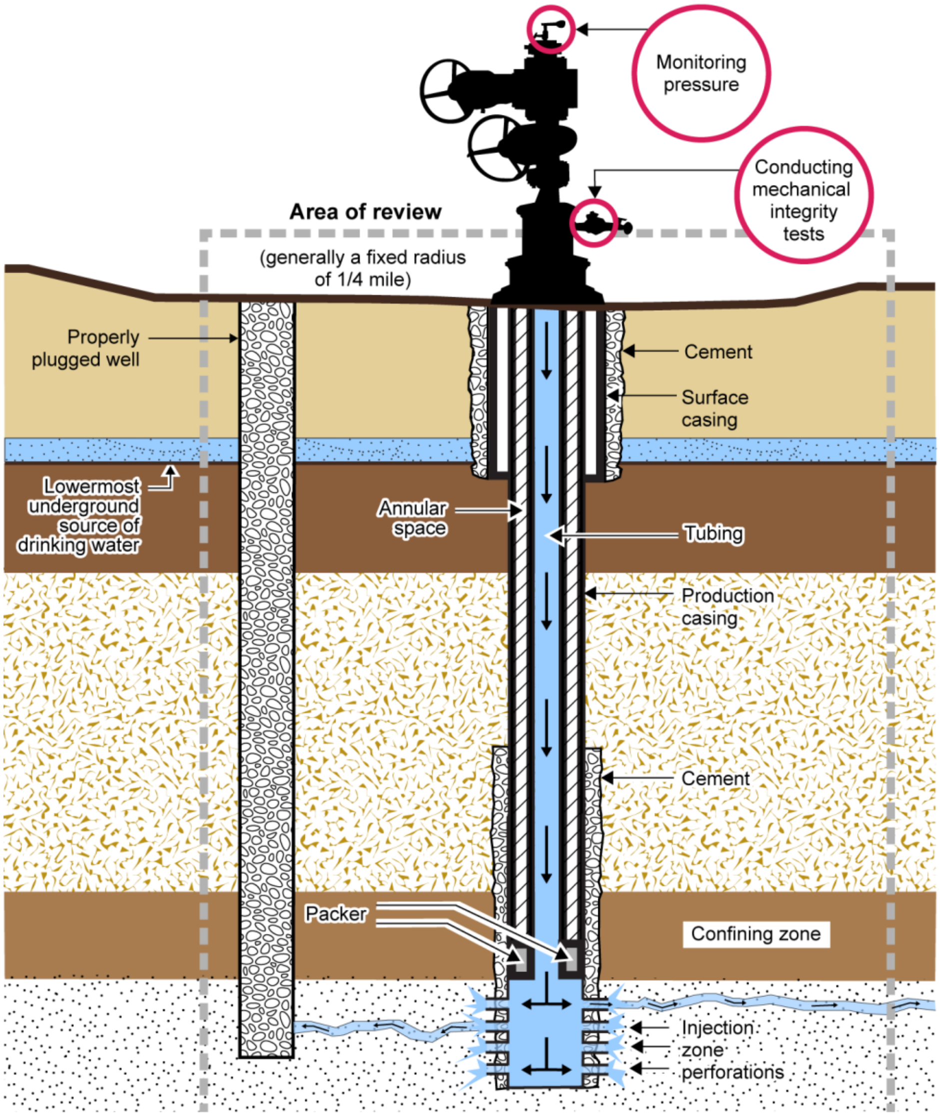
- Cement bond logs can be utilized to assess the integrity of wellbores regarding bonding between the casing and the adjoining formation.
- Wells that were plugged and abandoned can be reentered and re-drilled to remove the cement, plugs, etc.
- For those wells with cement bond logs that indicate potential leakage or inadequate bonding, a cement squeeze can be used to reestablish integrity.
- Post re-completion mechanical integrity testing (often required by regulation) can determine the hydraulic integrity of the re-completed well.

Most wells in CO_2 EOR service are cemented with standard Portland cements. While the chemical degradation of Portland cement by carbonic acid ($H_2O + CO_2 \leftrightarrow H_2CO_3$ [carbonic acid]) is well known, field experience suggests that the dynamics of this process may not necessarily be as problematic as laboratory data suggests. For instance, one study on conventional Portland-based well cement samples exposed to CO_2 for 30 years from a 52-year old SACROC well found limited evidence of cement degradation. [1] Parker et al. (2009) [151] have suggested that CO_2 WAG represents the worst-case for wells and related surface equipment, due to the long-term exposure to carbonic acid. Comparatively, CCS injection wells are expected to inject CO_2 in a dry state (similar to CO_2 EOR transport pipelines), inhibiting the formation of corrosive carbonic acid solutions within the injection well. Solutions to limiting the cement degradation caused by carbonic acid formation in the reservoir near these CCS injection wells usually involve the addition of materials like fly ash, silica flour, or other acid resistant materials—reducing the proportion of Portland cement in the total mixture. These specialty acid-resistant cements are available but have not been widely used in CO_2 EOR applications, mostly due to their higher costs, and adequate historical performance has been observed of standard Portland type oil well cements. [151] In general, conventional Portland-type oil well cements provide adequate performance in most CO_2 exposure situations.

CO_2 EOR injection wells may be either drilled as new wells or can be created by converting and re-completing existing wells to a CO_2 injection wells. [1] The primary objective in the construction of a UIC Class II injection well for CO_2 EOR is the protection of groundwater by assuring containment through a multilayer protection system. [152] Since these concerns are not as paramount during water injection, well design parameters can change between the primary or secondary recovery phases, and the tertiary recovery phase. For instance, added considerations for corrosion potential of produced and injected fluids must be accounted for in well design for a CO_2 EOR application. Additionally, in CO_2 EOR applications, injection wells are considered more susceptible to CO_2 WAG corrosion effects than production wells. This is due to a coating effect from the hydrocarbons present in the fluids of production wells (not present in injected fluids) helping to inhibit corrosion of production wells. Regardless, corrosion can still occur in production wells. [151]

For new well construction, the well is drilled to below the lowermost USDW and a steel surface casing is installed and cemented to surface that runs the entire length of the hole. The well is then drilled to the completion zone at total depth (TD) and production casing (typically carbon steel) [1] is run from the injection zone to the surface and set in cement from TD to several hundred feet above the injection zone. Wells ranging 10,000 ft or less in depth typically use carbon steel casing (J-55 and K-55 grades being common). In deeper and high-pressure reservoirs with high-temperature environments, higher strength grades may be used. [153] Injection tubing is placed inside the production casing and a packer is set above the injection zone to isolate the annulus, the area between the injection casing and injection tubing, from corrosive fluids. Exhibit 4-7 shows a schematic for Class II injection well construction.

Exhibit 4-7. UIC Class II injection well schematic with safeguards [154]



Source: U.S. Government Accountability Office

In CO_2 EOR applications, the WAG-related equipment costs can be much higher in injection wells compared to production wells due to higher pressure and higher corrosion potential. In Brownfields where current wells are used to develop access, well designs are limited by the existing completions. To prevent corrosion, operators employ several techniques to ensure the well components do not degrade due to exposure to CO_2 and water. For instance, squeezing acid resistant cements in zones adjacent to and above the CO_2 injection interval(s) that are susceptible to cement carbonation can occur. Cathodic protection of the casing string enables operators to employ both impressed and passive current techniques on the casing string to counteract naturally occurring galvanic corrosion. Additionally, following well completion, a biocide/corrosion inhibitor fluid is placed in the annulus of the well to further restrain any corrosive tendency. [1]

Wells are also affixed with monitoring equipment to detect variation from normal operation (Exhibit 4-7). For instance, the pressure of the fluid in the annulus can be monitored for any changes in the system that may indicate leakage. [152] Specific casing and cementing plans for each newly drilled well must be designed according to site-specific factors, like the depth to the injection zone, anticipated injection pressure, external pressure, internal pressure, axial loading, hole size, size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material), corrosiveness and temperature of formation fluids, and specific lithology of injection and confining intervals, as well as the type or grade of cement.

Federal (EPA) or state authorities regulate the construction of Class II wells, as summarized in Section 3.1.1. The specific federal construction requirements for Class II injection wells are detailed in 40 CFR 146.22 which specifies:

- Well must be cased and cemented to prevent fluid movement.
- Well logs and other well tests are required during the drilling and construction of new Class II wells.
- Properties of the injection formation need to be measured or calculated, including fluid pressure, estimated fracture pressure, and physical/chemical properties of the injection zone.

Well design details to meet these requirements are submitted during the permit application process, which is reviewed, and needs approved by the permitting authority (federal or state depending on primacy for Class II wells) before a well can become operational.

4.4 Production Operations, Implementation, Performance, and Monitoring

There are several operational aspects that need to be considered before and during implementation of CO_2 EOR in a suitable oil reservoir. While not entirely exclusive, some major items include: [30]

- Acquiring a CO_2 source (either anthropogenic or naturally-occurring) that can supply sufficient volumes of CO_2 over the expected life of the flood.
- Installation of the necessary surface equipment capable of extracting fluids from the subsurface and separating them for proper disposition or reuse. CO_2 can be recycled, recompressed, and reinjected as part of the CO_2 flood. Produced water requires proper management (either reuse in the WAG or disposed). Oil will be sent off for sale.
- Require installation, monitoring (metering), and maintenance of gathering and distribution lines for all fluids types.
- Implementation of effective monitoring and reservoir surveillance over the life of the CO_2 flood.

Once wells are constructed, and prior to tertiary injection operations, a variety of tests are run either as best practices or to meet regulatory requirements. For instance, a mechanical integrity test (i.e., MIT) where pressure within various well components is temporarily elevated, monitored, and recorded for a certain period and observed for any variation in pressure stability is required for all wells. Logging programs can show the condition of the casing and cement or diagnose indications of non-conforming fluid flow behind casing. The MIT and sometimes other types of well integrity tests are also required at regular periods during well operation and prior to abandonment of the well. [155] Both internal and external mechanical integrity is crucial for a successful CO_2 EOR flood operation. Internal integrity refers to the absence of leaks in the casing, tubing, or packer, which prevents contact between the injected CO_2 and the surrounding formations. Tests such as the standard annulus pressure test, the standard annulus-monitoring test, and the radioactive tracer survey are used for internal mechanical integrity. An external mechanical integrity test is intended to ensure that the injected CO_2 and other formation fluids (like brine) do not migrate upwards from the injection zone, which would demonstrate zonal isolation of the injected CO_2. Cement is the main component that prevents fluid movement by sealing the space between the casing and the geologic formation, as well as provides protection for the well casing from added stress and corrosion. Tests such as temperature and sonic logs, cement bond logs, ultrasonic logs, borax/neutron logs, and radioactive tracer surveys can help monitor for external integrity. [156]

Near-surface, surface, and atmospheric monitoring is another group of monitoring technologies that involves a range of established techniques for the detection and measurement of CO_2 and other gases that could have possibly migrated to groundwaters, the soil, or into the air. While helpful in determining if any leakage could be resulting from CO_2 injection, this type of monitoring is not required per 40 CFR 146.23 for operating, monitoring, and reporting requirements for UIC Class II wells at the federal level. Surface-flux monitoring is one way to monitor for leakage of CO_2 (or other gases) into the atmosphere over large-scales. Direct measurement techniques include covariance towers, flux accumulation chambers, and instruments such as a field-portable, high-resolution infrared gas analyzer. Year-round monitoring is needed to distinguish leakage from the highly variable natural biological CO_2 fluxes caused by microbial respiration and photosynthesis at the surface. These technology examples provide onshore application and are widely used. Seismic imaging can potentially be useful for monitoring the injection zone in time-lapse fashion. For instance, time-lapse seismic surveys of the subsurface prior to and during CO_2 injection is one approach CO_2 storage stakeholders are investigating as a means to track CO_2 plume propagation. [157] [158] It could also be applicable for CO_2 EOR. While not a requirement for Class II wells per the UIC Program, this type of monitoring could be helpful in optimizing CO_2 flood performance.

Seismic surveys, geo-modeling, and subsurface surveillance techniques have advanced over the years and have had a measurable impact on delineating previously uncharacterizable features of many reservoirs. Additionally, since the costs to acquire CO_2 are a substantial portion of the cost to operate CO_2 EOR, operators could take more interest in having more insight into the location of injection CO_2, as well as ensuring that it is contained and working within their oil reservoirs. [159] Passive seismic imaging has been used to track gas movement during CO_2 injection in the Weyburn Field, Saskatchewan, Canada. [160] In a case study, an array of 8 triaxial geophones was permanently deployed in an abandoned well, to monitor induced seismicity in the field associated with CO_2 injection in a well 50 meters away. Recorded events clustered in a discrete region extending from the injection well to a neighboring horizontal production well, demonstrating the applicability of imaging gas injection with passive seismic monitoring. K waves, which are low frequency and travel long distances, can also be used. Similar to light in fiber optic cables, K waves stay "trapped" in the reservoir. [161] The technique assesses late arrivals to determine slow lateral propagation using wave energy transfers through the liquids.

4.4.1 Area of Review

The AoR is an area surrounding an injection well described according to the criteria set forth in 40 CFR 146.06, or in some cases of an area permit, as the project area plus a circumscribing area of one quarter of a mile width. Essentially, an injection site area is represented by a circle with an exterior radius, or the lateral extent, which represents the area that could experience an event that could impact a USDW. The AoR provides the operator with an area that must be monitored to prevent fluids from entering a USDW. Additionally, analyses within the AoR are required to identify artificial penetrations, such as other wells, that might allow fluid to move out of the injection zone.

4.4.2 Produced Water Management

Large volumes of produced water and oil are returned to the surface during CO_2 EOR production—approximately 10 barrels of water for each barrel of crude oil. [162] These fluids, which contain high concentrations of TDS, sometimes naturally occurring radioactive minerals, oil and grease, and approximately 40 percent of the injected CO_2, require proper management. Inadequate treatment before discharge can be damaging to USDWs and the environment. Management technologies include recycle/reuse, and deep well disposal.

The first step to recycling and reuse involves the separation of the water and CO_2 phases from the hydrocarbon stream. The CO_2 can then be treated (dehydrated), compressed, and re-injected for subsequent EOR activities. [2] Produced water can be recycled for waterflooding, WAG, or reservoir pressure support. It can also be treated and used for agricultural or domestic use, as well as for possible surface discharge. Depending on the intended end-use for produced water, differing levels of treatment may be required. Disposal may take place via subsurface injection. UIC Class II wells are also used for the disposal of liquid wastes associated with oil and gas operations. Even with water treatment, some form of disposal will likely be required to manage solids and high-concentration brine streams produced from treatment. [163] Lastly, produced water waste streams will likely require some form of transportation, for either reuse or disposal.

4.5 Closure

Most site closure activities will take place once all injection has ceased. Site closure activities could include decommissioning surface equipment (associated with injection), plugging injection wells, restoring the site, and preparing and submitting site closure reports. In addition, the land could be reclaimed to a pre-development state or for other uses (like agriculture). [164]

[165] Site closure, as described here, relates specifically to the cessation of injection operations. Once a Class II well ceases operation, 40 CFR 146.10 requires the well must be plugged with cement to prevent the movement of fluids either between or into USDW. No post operation site monitoring is required.

5 CO_2 GEOLOGIC STORAGE: TECHNICAL DIGEST AND PROJECT PHASES

CO_2 geologic storage is the process of injecting CO_2 captured from an industrial (e.g., cement processing plant) or energy-related source (e.g., power plant) into deep subsurface rock formations for long-term storage (i.e., saline-bearing formations). [5] This section provides a brief, but comprehensive, overview of CO_2 storage in terms of the general concept, key technical considerations and requirements, and insight into successes (and where applicable, challenges) of field-based R&D and commercial-scale projects. The information in this section will provide a basis from which to compare CO_2 storage operations using Class VI wells with the analogous CO_2 EOR practices using Class II wells (outlined in Section 4). Outlining the technical considerations and operations for each practice is important towards fully understanding the major similarities and differences between CO_2 EOR and CO_2 storage operations.

5.1 CO_2 GEOLOGIC STORAGE TECHNICAL OVERVIEW

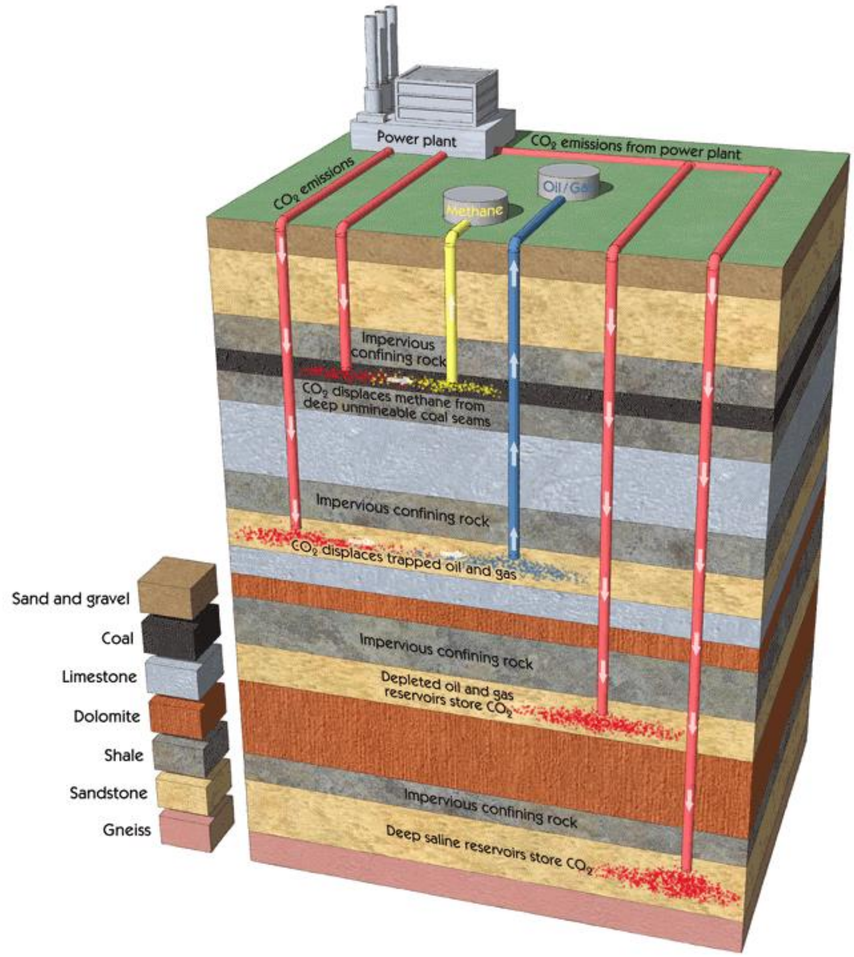
According to the Intergovernmental Panel on Climate Change, geologic storage of CO_2 currently represents the best and likely only short-to-medium term option for significantly reducing the CO_2 emitted into the atmosphere. [4] This is further supported in the International Energy Agency's (IEA) *Energy Technology Perspectives* studies, in which CCS is a vital component within a portfolio of low-carbon energy technologies needed to attain emission reduction trajectories in scenarios like 2DS.[m] [166] The practice of storing CO_2 underground could be applied immediately based on the experience to date from the oil and gas industry and from the deep disposal of liquid wastes. [4] The storage of CO_2 in geologic formations shares many comparable features to oil and gas accumulations in hydrocarbon reservoirs and CH_4 in coalbeds. The transportation, injection, and monitoring of CO_2 in the subsurface has been implemented for decades for EOR, while other industries, such as acid gas disposal, deep wastewater and hazardous waste injection, and natural gas storage, are analogous to geologic CO_2 storage and have been in successful operation for decades. [22] The worldwide experience with these types of industrial analogs demonstrates that the technology of bringing CO_2 to a geologic storage site and injecting it deep into the ground currently exists and can be easily applied. Although the technologies pertaining to each component of the CCS value chain (CO_2 capture, transport, and storage) are at various stages of maturity, and in some cases, they have been separately proved and deployed at commercial scales (like CO_2 pipelines, and injecting CO_2 into the subsurface for EOR applications), [167] fully-integrated CCS systems are still considered costly and not entirely matured. [168] [169] Continued research is needed to significantly improve the effectiveness of CO_2 storage-related technologies, reduce the cost of implementation, generate operational data, illustrate best practices, and provide for lessons learned. This type of information can be used to inform regulators and industry on the safety and permanence of CCS and help toward facilitating widespread commercial deployment. [17]

[m] The 2DS as described by IEA is based on technology implementation across all energy sectors that would achieve an 80 percent chance of limiting average global temperature increase to 2 degrees Celsius (°C) by the 2050 timeframe. [291]

Generally, five storage formation types, each having unique challenges and opportunities, have been considered candidates for carbon storage: 1) depleted oil and gas reservoirs, 2) unmineable coal seams, 3) saline formations, 4) organic-rich shales, and 5) basalt formations. However, long-term CO_2 storage using Class VI wells is most likely to occur in saline-bearing formations. CO_2 EOR using UIC Class II wells, as an analog to CO_2 storage in Class VI wells, occurs primarily in depleted oil and gas formations. CCS involves candidate storage site selection through screening and initial characterization followed by a more detailed site characterization utilizing seismic surveys, core analysis, and modeling. These efforts help ensure that candidate storage sites can safely store CO_2 for extended periods. MVA efforts focus on the development and deployment of technologies that can provide an accurate accounting of stored CO_2 and a high level of confidence that it will remain safely and permanently stored during and after the injection process. Risk assessments are conducted throughout the CCS process to identify and quantify the potential health and environmental risks associated with carbon storage and help identify appropriate measures to ensure that those risks remain low. [15] [170]

Identifying suitable geologic storage sites involves a methodical and careful analysis of both the technical and non-technical aspects of potential sites. Geologic storage of CO_2 is accomplished by injecting it deep enough (~2,600 ft or greater) to take advantage of its dense, supercritical phase, which maximizes use of available storage (see Exhibit 5-1—offshore storage not demonstrated in this example). Porous rock formations that hold, or (as in the case of depleted oil and gas reservoirs) have previously held, fluids such as natural gas, oil, or brines, are promising potential candidates for CO_2 storage. Large-scale injection of fluids into the deep subsurface for disposal of produced water from oil and gas operations, injection of water for a waterflood to repressurize a depleted oil reservoir, or injection of CO_2 to enhance oil production has occurred for many decades. On a smaller scale, injection disposal of hazardous and non-hazardous wastes has also occurred for many decades. The basic principles involved in such activities are well established and most countries have regulations governing them. In the United States, EPA's UIC Program is the primary governing body for underground fluid injection. Captured CO_2 stored through injection has, to date, been performed on a relatively small scale, but if it were to be used to significantly capture and manage a sizeable portion of emissions from existing stationary sources, the injection rates would have to be on a scale similar to water injection in many oil and gas operations. [4]

Exhibit 5-1. Conceptual diagram of captured CO_2 from a power plant being stored in diverse types of storage formations specific to an onshore setting [171]

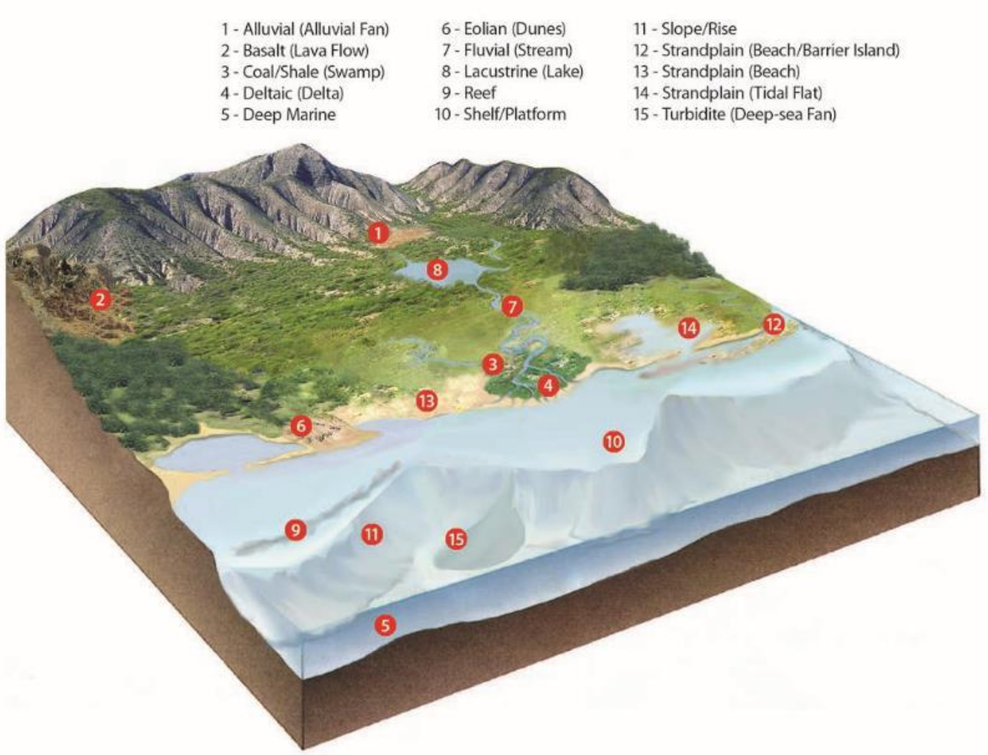


Source: Ohio Department of Natural Resources

Suitable storage formations can be in both onshore and offshore sedimentary basins (natural large-scale depressions in the earth's crust that are filled with sediments, i.e., sedimentary rocks). [4] Basins suitable for CO_2 storage have a thick accumulation of sediments with formations that can be porous and permeable (storage reservoir candidates) or tight (seal/caprock candidates), having almost no porosity and permeability. Each type of geologic formation presents different opportunities and challenges. For instance, within a given formation, there could be the presence of both high permeability and high porosity storage reservoir zones, as well as low permeability zones that can trap fluids (liquid or gas) within the storage reservoirs and prevent movement to overlying formations. Within the reservoir, the distribution of porosity and permeability is determined by constituent mineralogy (sand, carbonate, shale) reflecting depositional environments. The depositional environment (Exhibit 5-2) influences reservoir architecture, how injected fluids will move through the reservoir and be held in place. Certain geologic properties may be more favorable for long-term containment of liquids and gases within individual storage reservoirs. [14] In the IEA Greenhouse Gas R&D Programme document *Development of Storage Coefficients for CO_2 Storage in Deep Saline*

Formations Technical Study, depositional environments that represent the most common settings for sedimentary rock accumulation have been assessed based on their unique properties, which impact the behavior and, inevitably, the storage capacity of the given environment. [172]

Exhibit 5-2: Schematic of possible depositional environments [170]



For fluid flow in porous media, knowledge of how depositional environments formed, and directional tendencies are imposed by the depositional environment can influence how fluids flow within these systems today, and how CO_2 in geologic storage might flow in the future. The fluid(s) contained within the candidate storage formation are also of importance and can influence the approach toward the injection of CO_2.

5.2 GEOLOGIC STORAGE FORMATIONS

Optimal storage of CO_2 in the subsurface occurs when the injected CO_2 is in its supercritical phase. Supercritical CO_2 exists at temperatures more than 88 °F (31.1 °C) and pressures more than approximately 1,057 psi (72.9 atmospheres). At these temperatures and pressures, CO_2 has properties like those of both a gas (viscosity) and liquid (density). The main advantage of storing CO_2 in the supercritical state is to maximize utilization of available storage volume. [14] Temperature and fluid pressures are greater than the supercritical point of CO_2 in most places on Earth at depths below about 2,600 ft (800 meters). CO_2 injected at this depth or deeper will remain in the supercritical state. [17] Under these high pressure and temperature conditions, the density of CO_2 will range from 50 to 80 percent of the density of water depending on specific site conditions. [4] Injecting CO_2 in the supercritical phase is also a preferred approach for CO_2 EOR as supercritical CO_2 has properties that make it an effective solvent for many oils under miscible conditions (discussed in Section 4.1.1 above). [136]

Three of the most promising underground storage reservoir types include saline, depleted oil and gas reservoirs, and unmineable coal seams. Other potential storage reservoirs may be found in organic-rich shales and basalt formations. These types of storage reservoirs can be found throughout the world and have the resource potential to hold CO_2 emissions from large point sources into the distant future, with the largest potential storage capacity of these formations found in saline-bearing formations (particularly in the United States). [173] While there are indeed several possible formation types for storing CO_2, the subsections below focus on the overview and discussion of the advantages and challenges to storing CO_2 in saline-bearing formations. Class VI permits issued to date (such as the Illinois Basin Decatur Project [IBDP], the Illinois Industrial CCS Project [ICCS], and the canceled FutureGen 2.0 Project) have been for saline reservoirs. [174] [175]

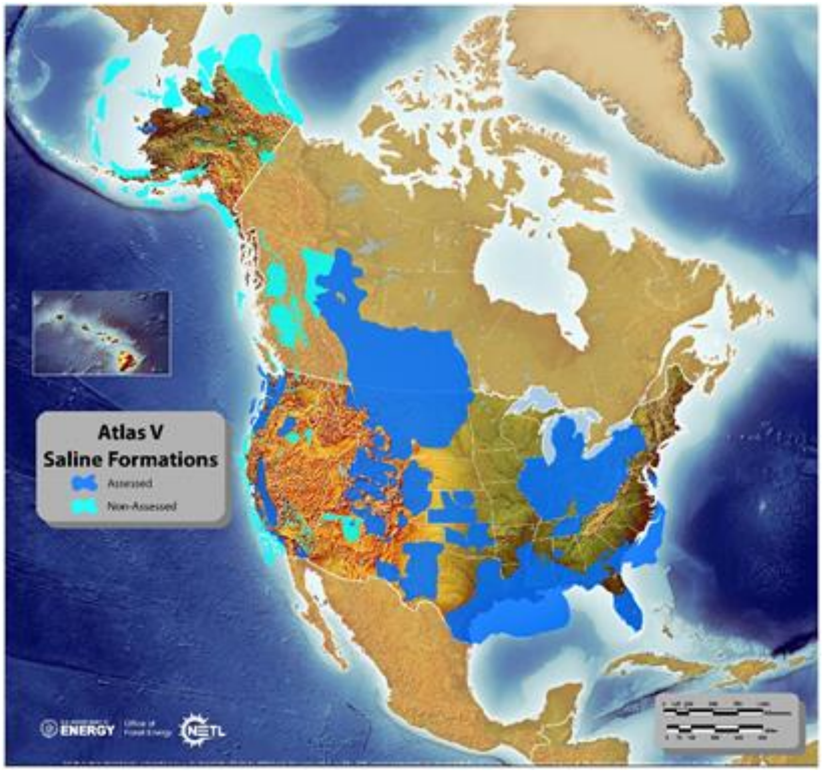
5.2.1 Saline Formations

Located both in the United States and globally, deep saline formations have the greatest potential to store anthropogenic CO_2 because of their large areal distribution and storage resource potential. These formations occur in both onshore and offshore sedimentary basins. [4] CO_2 storage resource estimates for saline formations in North America conducted by NETL and RCSPs range between 2,379 and 21,633 billion tonnes (Exhibit 5-3).[n] [14] These resource estimates for storage capacity (calculated at the formation, basin, and continent scales) are not always straightforward. Saline formation storage lacks the economic incentives of an EOR project; however, it could serve as buffer storage for EOR operations.

Formation waters contain appreciable amounts of salts that have either been leached from the surrounding rocks or from seawater that was trapped when the rock was formed. To protect USDWs, EPA has determined that the water or brine of a saline formation used for CO_2 storage must be greater than 10,000 parts per million (ppm) TDS—a measure of the amount of dissolved solids, mostly salts, in formation water. Most drinking water supply wells contain a few hundred parts per million or less of TDS. [5] The brine concentrations in saline formations typically considered for geologic storage of CO_2 make the fluids difficult to treat and render suitable for agriculture or human consumption.

[n] CO_2 resource assessments included in Section 5.2.1 are calculated from low (P_{10}) and high (P_{90}) efficiency factors. [14] The methodology for this approach is outlined in Appendix F: Overview of the United States Department of Energy Methodology for Estimating Geologic Storage Potential for Carbon Dioxide for saline-bearing formations.

Exhibit 5-3. Map display of saline formations in parts of North America that were assessed by NETL under the RCSP initiative [14]



Potential storage reservoirs require a confining zone (often referred to as a caprock or seal) that overlies the porous rock layer providing a primary trapping mechanism for the stored CO_2. Other, secondary trapping mechanisms within the reservoir include CO_2 dissolution into brine (solubility trapping), chemical reactions with the minerals and fluid to form solid carbonates (mineral trapping), or trapping of migrating buoyant CO_2 (residual trapping). A great deal of knowledge about certain saline formations exists because of prior oil industry experience in oil and gas exploration and production. However, that attained knowledge was ancillary as part of the pursuit of hydrocarbon resources. Also, there are a great many saline formations about which little is known. The potential for successfully storing CO_2 in saline formations is more uncertain than that in oil and gas reservoirs as saline reservoir management parameters are less well defined. However, saline formations are widespread with enormous storage resource potential. Recent CCS projects are proving the potential for reliable, long-term storage (discussed in Section 5.7). [4] [6]

5.3 Key Geologic Characteristics Common to Successful Underground CO_2 Storage

The oil industry has developed full-system approaches for safe and cost-effective injection of CO_2 into the subsurface for EOR applications. Over 40 years of industry experience indicate that CO_2 EOR projects have been successfully implemented that demonstrate CO_2 injection into the subsurface covering a range of depths, reservoir qualities, pressures, and temperatures. Additionally, pilot and commercial-scale CO_2 storage projects in saline formations as well as unmineable coal seams have also occurred. Several projects worldwide have implemented and validated, or are continuing to implement and validate, safe and effective CO_2 injection and storage operations for long-term subsurface CO_2 storage. [6] [15] [173] Safe, efficient, and reliable long-term storage of CO_2 requires knowledge and observance of key parameters and reservoir characteristics that, based on historical CO_2 EOR and CCS-demonstration projects, go into the design and construction of a successful project that can deliver an efficient and reliable result. From a technical perspective, a CO_2 storage site operator planning to inject into a saline-bearing formation using a Class VI well must ensure, at a minimum, that the candidate storage site: [176]

- Has the necessary capacity for storage
- Meets the conditions necessary for injectivity of CO_2 in the subsurface at the desired rate
- Has adequate depth to store CO_2 in a supercritical phase (typically greater than 2,600 ft)
- Provides for safe injection and storage such that CO_2 leakage is avoided, or, if it happens, it is minimized and benign
- Is constructed, operated, and monitored to assure safe operations
- Establishes non-endangerment for site to be decommissioned

Many of the requirements in the list above can be directly attributed to key geologic characteristics that are common to safe, efficient, and successful CO_2 storage operations; injectivity (rate at which CO_2 can be injected), capacity (volume of CO_2 the subsurface can hold), and containment (CO_2 retention in the subsurface). [177] [178] The key geologic characteristics that are foundational to these criteria are presented below.

- **Injectivity** is the measure of the ability of a formation or reservoir to accept fluids or gas. Units of injectivity can vary with the data source and include cubic meters/day/Pascal/meter or barrels/day/psi/ft. Injectivity is proportional to a formation's permeability (often expressed in mD). Injection is directly proportional to permeability, height or thickness of reservoir open to injection, and the bottom-hole and reservoir pressure differential. Horizontal wells expose more of the reservoir to the wellbore for injection providing for larger injection rates while maintaining safe injection pressures below fracture gradient. Injectivity can be estimated for a given site by several means, including data from past production history (especially for oil and gas fields), injection or leak-off tests, well pump/injection tests, conventional core analysis, and injectivity from analogous reservoir types. [164]
- **Capacity** is a measurement of the potential volume of a given formation for storage of a liquid or gas. Pore volume is a bulk term based on the product of formation thickness, area, and porosity. Estimates of pore volume can be derived from data generated through core analysis, wireline logs, or geophysical surveys; in some cases, three-dimensional (3-D) seismic surveys may be combined with existing well data to estimate the formation porosity. [179] [180] A second key parameter in estimating capacity is the CO_2 utilization factor, or the effective pore volume. [172] [181] This is the fraction of the

pore volume that would retain or store injected CO_2. Utilization factors, or storage coefficients, are a function of the fluid already present in the reservoir, and reservoir heterogeneity at all scales, ranging from pore-throat diameters to kilometer-scale connectivity, unit architecture, and residual phase (or capillary) trapping. [172] The utilization factor is also a function of the development strategy and injection well planning, such that capacity can be increased by more wells, through optimized well design, and/or placement of wells in the reservoir. [164]

One approach to estimating CO_2 storage capacity developed by the U.S. DOE is based on volumetric methods and considers in situ fluid distributions and fluid displacement processes. The U.S. DOE methodology is intended to produce high-level estimates of CO_2 storage resource potential in saline-bearing formations, depleted oil and gas reservoirs, and unmineable coal seams. This resource estimate is on a regional and national scale for the United States and Canada. Like oil and gas resource estimates, CO_2 storage estimates will be proved through site-specific characterization and operations. [181] A brief overview of the DOE methodology for saline formations is presented in Appendix F: Overview of the United States Department of Energy Methodology for Estimating Geologic Storage Potential for Carbon Dioxide. The U.S. Geological Survey (USGS) developed a probabilistic assessment methodology to evaluate geologic CO_2 storage that uses Monte Carlo analysis of all critical factors to express the assessed capacity as a range in P10, P50, and P90. The USGS methodology is for estimating the storage resource of an individual storage assessment unit and requires substantial unit-specific data to conduct the analysis. [182] There are several other documented CO_2 storage capacity estimation approaches in existence in addition to the USGS and U.S. DOE approaches. In 2011, IEA invited experts from the geological surveys of Australia, Canada, Germany, the Netherlands, the United Kingdom, and the United States to seminars to explore ways to improve the consistency of geologic storage resource estimates. As part of the IEA seminars, six CO_2 storage atlases which contained capacity estimation methodology for different countries/regions were reviewed. Findings from the review indicated that there were significant differences between the methods and their applications. For instance, the participants concluded that the methodologies were not all based on the same scientific assumptions, they all relied on acquiring differing amounts of data, and they would produce wide ranges of capacity estimates. [183] The report generated from the seminars outlined key considerations for estimating a storage resource and contrasted the approaches used from the different countries. Additionally, the report provided best practices and guidance that should be followed to conduct CO_2 storage resource assessments across geologic settings, regardless of the amount of available geologic data, moving forward. In many instances, the USGS methodology discussed above contained many of the IEA report's suggested guidance (probabilistic capability, subdivision of geologic units for assessment, and a strong go-by for efficiency factor use). [183] Conversely, the U.S. DOE methodology discussed above is deterministic in nature and intended for use on the regional and national scale. But, the development of the CO_2-Storage prospeCtive Resource Estimation Excel aNalysis tool by NETL enables implementation of the U.S. DOE methodology to account for geologic unit subdivision to the formation scale and enables probabilistic analysis capability; [184] [185] which enables better alignment of the U.S. DOE methodology to the IEA report's suggested guidance.

- **Containment** is essential for effectively storing large volumes of CO_2 in the subsurface. Since injected CO_2 is buoyant relative to other subsurface fluids (formation brine), gravitational (buoyancy) forces will drive CO_2 upward from the injection point to the top of the storage formation. A confining zone (also called a caprock, confining unit, or seal) is a geologic formation that overlies the reservoir formation preventing further migration. For a confining zone to be effective, it must 1) be laterally extensive and thick enough to counter the total buoyant forces of the accumulated CO_2 in the reservoir, 2) possess low vertical permeability, 3) have high capillary entry pressure, 4) possess sufficient thickness, and 5) be void of leakage conduits (either improperly sealed wellbores, extensive fracturing, or faulting). Marine and lacustrine shales and thick deposits of evaporites (like anhydrite/gypsum and salts) are common caprocks in a confining zone. Containment through this physical trapping contains very high fractions of CO_2 and acts immediately to limit vertical CO_2 migration. However, other trapping mechanisms (e.g., capillary trapping, dissolution trapping, and mineral trapping) can often work in combination to ensure that CO_2 remains in the storage reservoir. [164]

Not all the information necessary to assess these factors is typically readily available without investing in drilling, surveying, and sampling activities. Many of these parameters are identified during the initial screening and site-selection phases of a potential CCS project, and further validated through the site characterization phase (see Section 5.4 for details on these phases). Furthermore, the key parameters discussed above are consistent with those required for successful Class II well design and operations, which include 1) capacity, 2) injectivity, and 3) containment. Appendix G: Selected Characteristics of Carbon Capture and Storage Projects Worldwide provides a list of a selected group of ongoing or recently completed CCS projects that features each project's key geologic characteristics for a comparative analysis of successful and non-successful injections.

While these technical considerations are a must, a potential CCS operator must also consider whether the project is economically viable from a cost-effectiveness perspective, is acceptable to the public, and meets the necessary regulatory requirements for CO_2 injection.

5.4 Phases of a Geologic CO_2 Storage Project

CO_2 injection and storage projects can be complex undertakings. As mentioned in Section 5.3, a CO_2 saline storage site operator should ensure, at a minimum, that the candidate storage site 1) has the necessary capacity for storage; 2) meets the conditions necessary for injectivity to introduce CO_2 in the subsurface at the desired rate; 3) has adequate depth to contain CO_2 as a dense phase (typically greater than 2,600 ft); 4) provides for safe injection such that CO_2 leakage is prevented; 5) is safely constructed, operated, and monitored; and 6) is safely decommissioned. [176] There is a sequence of steps and actions for developing and implementing a CO_2 storage project that can be broadly divided into the following major CO_2 storage project phases:

- **Site screening and selection:** Involves evaluating regions and sub-regions that are potentially suitable for CO_2 geologic storage based on analyses of readily accessible data. CO_2 source-to-sink matching is also critical. Potential sites that meet the necessary screening criteria can be selected for further, detailed characterization
- **Site characterization:** Builds on screening of selected sites to develop a more detailed characterization and understanding of the subsurface to assess a potential site's suitability for storage as a function of containment, injectivity, and capacity
- **Permitting (injection):** Utilizes data from site characterization to build a CO_2 injection permit application. Once an injection permit is approved, injection wells are drilled, tested, and correlated with submitted geologic data; CO_2 injection authorized. MVA wells and equipment are also installed
- **Operations:** Begins pre-injection drilling; operational planning commences; active transportation and injection of CO_2 occurs; site monitoring is conducted
- **Closure of injection operations:** Involves the cessation of CO_2 injection; injection well(s) will be plugged, the associated equipment will be removed
- **PISC and site closure:** Includes monitoring of storage reservoir to assess stability of CO_2 plume and establish non-endangerment. Once non-endangerment is declared, site closure can be completed

Specific guidance for many of these phases are provided under 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. These regulations have been summarized in Exhibit 3-2 in Section 3.1.3. However, the exact approaches used and implemented for each phase could vary from project to project, and site to site. The following subsections describe each of the project phases in more detail.

5.4.1 Site Screening and Selection

The first step in any CO_2 saline storage project is to identify potential reservoirs amenable to the process. Aspects to be considered include reservoir depth, porosity, areal extent, thickness, permeability, and the state of reservoir seals. Like CO_2 EOR, these aspects are of critical importance to a given site's injectivity, capacity, and containment. For instance, UIC Class VI guidance pertaining to siting criteria indicates that Class VI wells must be sited in areas with a suitable geologic system, which includes (per 40 CFR 146.83):

- An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream
- Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s)

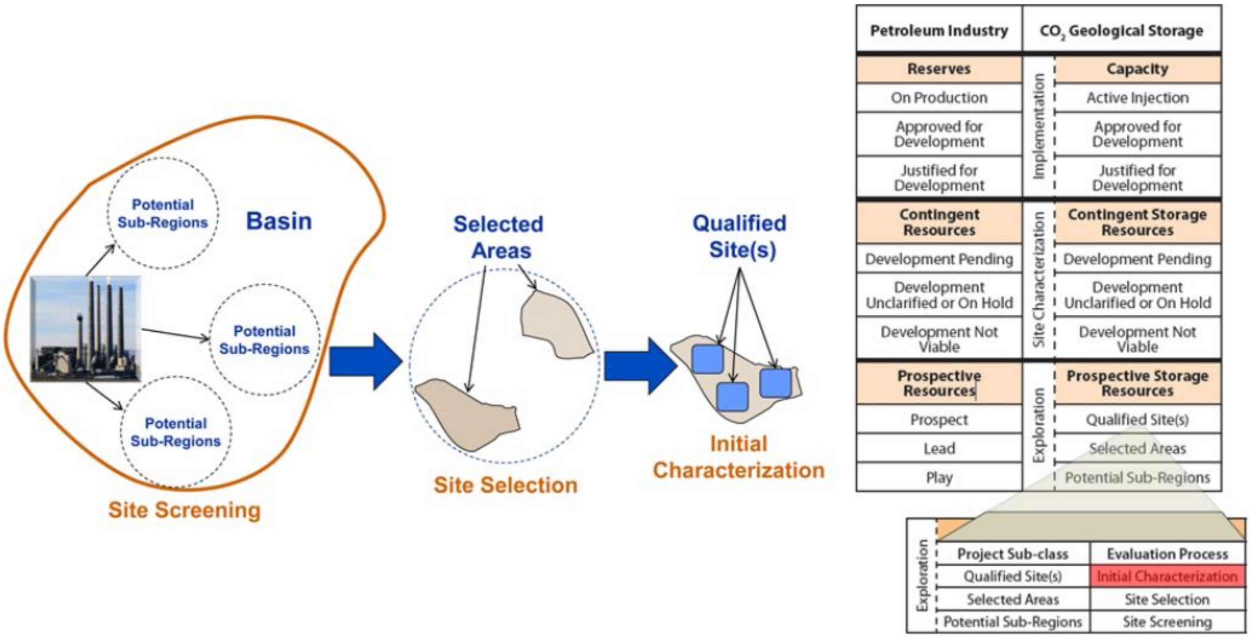
In addition, matching sources of CO_2 to potential storage sites—considering projections for future socio-economic development—is s also particularly important. [4] Therefore, the site screening phase involves the evaluation of regions and sub-regions that are potentially suitable for safe CO_2 injection, capacity, and retention. The analysis in this step relies on readily accessible information that can be obtained from public sources (e.g., data, reports, masters/doctorate thesis or professional papers, etc.) from state geological surveys, state departments of natural resources, groundwater management districts, academic research, previous EPA UIC injection well permits, and the U.S. National Carbon Sequestration Database and Geographic Information System (NATCARB) [186] Technical information to be collected from these sources during initial characterization of down-selected sites includes existing core sample data, well log data, available seismic surveys, records from existing or plugged and/or abandoned wells, and other available geologic data (some of which may have to be purchased from third-party vendors, which would be more prudent than acquiring new characterization data). [186] Adequate porosity and thickness (for storage capacity) and permeability (for injectivity) are critical components of a suitable storage site. It is also important to determine if the storage formation is capped by extensive confining unit(s) (such as shale, salt, or anhydrite beds) to ensure that CO_2, brine, or other fluids do not migrate to overlying, shallower rock units and, possibly, to the surface. [4]

A preliminary estimate of an AoR [187] could be developed during the initial characterization stage. The AoR is a region surrounding the geologic storage project where USDWs may be endangered due to the elevated pressure in the storage reservoir. It is delineated using computational modeling that accounts for the physical and chemical properties of the injected CO_2 stream and displaced fluids. The size of the AoR is a function of both the planned injection volumes and the target reservoir characteristics, and it can have a significant impact on the non-technical factors of a project, such as monitoring locations, property and pore space ownership, land use, and available infrastructure.

Other items to be addressed during the site screening phase is evaluation of surface access, as well as pore space ownership. From a surface access perspective, factors that should be considered include the location of geologic storage sites in relation to CO_2 emissions sources, competing land uses, impact on environmentally sensitive areas, terrain and topography, and availability of infrastructure. For CO_2 pipelines, surface and near-surface competition may come from other industries that require the same ROWs. This may include utility transmission lines, water pipelines, and oil and natural gas pipelines. There may also be roads, rivers, and railroads to traverse, requiring special easements or ROWs. In addition, surface competition for well sites may occur at CO_2 EOR sites, where well spacing may play a key role in injection and recovery rates. From a pore space ownership perspective, in the United States, the jurisdiction for pore space ownership resides with the states. However, the legal treatment of pore space at the state level varies significantly, and project developers should gain an early understanding of the state rules governing promising areas being considered in the site selection stage. [186]

Screened regions and sub-regions can then be ranked based on criteria established prior to initial screening, and the highest ranking selected areas can advance to the next evaluation stage (Exhibit 5-4). This process is analogous to the maturation of a petroleum project from "play" to "lead," and to "prospect." [186] Overall, the goal of the site screening and selection phase is to establish a down-selected list of potential qualified sites that may have the storage resource potential to accept and safely store the anticipated quantity of CO_2 at the injection rate needed for the storage project.

Exhibit 5-4. Graphical representation of a geologic storage project from site screening through selection of a qualified site for initial characterization. Petroleum-based and proposed CO_2 storage-based resource classification systems are included for perspective [188]



5.4.2 Site Characterization

Site characterization is one of the most important steps for ensuring the safety and integrity of a geologic CO_2 storage project as well as demonstrating that the site is capable of meeting required storage performance criteria outlined in Section 5.3. [4] Site characterization efforts are investigative processes in which the project operator acquires site-specific geological information to better understand (with supporting data) the geologic conditions that were identified during an early site screening phase. [15] Much of the site-specific data are collected, geologic and environmental baselines are established, and permit applications are developed during this phase. Permits could be required for certain site-characterization activities such as seismic reflection surveys or a stratigraphic test well. EPA has published several Class VI guidance documents intended to assist both UIC Program directors in implementing the Class VI program, and Class VI well owners or operators in complying with the Class VI regulations [189], including one specific to site characterization. [190] The types of site characterization information specified by the Class VI rule that must be provided with a Class VI well permit application include

- Maps and cross-sections of the AoR [40 CFR 146.82(a)(3)(i) and 146.82(a)(2)]; and the general vertical and lateral limits of all USDWs, water wells, and springs within the AoR, their positions relative to the injection zone(s), and the direction of water movement (where known) [40 CFR 146.82(a)(5)]

- Location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AoR, along with a determination that they will not interfere with containment [40 CFR 146.82(a)(3)(ii)]
- Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) and on lithology and facies changes [40 CFR 146.82(a)(3)(iii)]
- Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)]
- Information on the seismic history of the area, including the presence and depths of seismic sources, and a determination that the seismicity will not interfere with containment [40 CFR 146.82(a)(3)(v)]
- Geologic and topographic maps and cross-sections illustrating regional geology, hydrogeology, and the geologic structure of the local area [40 CFR 146.82(a)(3)(vi)]
- Baseline geochemical data on subsurface formations, including all USDWs in the AoR [40 CFR 146.82(a)(6)]
- Information on the compatibility of the CO_2 stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s) [40 CFR 146.82(c)(3)]
- Results of formation testing [40 CFR 146.82(c)(4)]
- All available logging and testing program data on the well [40 CFR 146.82(c)(7)]

The conceptual approach for site characterization and selection is a process in which a small number of candidate sites are identified based on readily available information and preferences. Then selected candidate sites are further investigated, including conducting site-specific risk assessments, to evaluate and rank them (Exhibit 5-4). As a site is characterized in further detail, the operator gradually begins to understand the distinctions of the site-specific geology. [164] Detailed site characterizations are conducted to finalize selection of the most suitable sites and prepare permit applications. The suitability of a site for storage is a function of its containment, injectivity, and capacity with specifics including 1) effectiveness of a confining zone in preventing upward migration of CO_2 and other fluids, 2) injectivity of the storage reservoir, and 3) volumetric capacity of the reservoir to hold injected CO_2. Similar to characterizing a new CO_2 EOR site, detailed site characterization tools may include both data collection (e.g., seismic and well logging, core analysis, and injectivity tests) and 3-D mathematical models of the selected injection and confining zone(s). [186] Much of the data collected at this point will necessarily be site specific, and data used for developing geological models will be used to simulate and predict the performance of the site (injection rates, CO_2 plume movement, pressure front estimation, refining the AoR estimate, etc.). [4] A critical goal of site characterization is to establish baselines for key geologic, geochemical, geomechanical, hydrologic, and flux parameters prior to CO_2 injection. These baseline values will be used later to support monitoring of a project providing reference points from which to identify changes resulting from CO_2 injection. [186] Site characterization may be easier to complete for areas for which significant pre-existing data is available (i.e., mature oil and gas fields). In areas for which very little pre-existing data about the subsurface are available (common for saline-bearing formations), site characterization could be a more complex process that may require more time and expense to complete. [164]

Successful site characterization is the most important step for ensuring the safe and economical operation of a CO_2 storage site that meets minimum UIC Class VI siting criteria specified in 40 CFR 146.83. [186] Other considerations when screening for and characterizing candidate storage sites include 1) extensively faulted and fractured sedimentary basins, or parts thereof, that may require careful characterization to determine if they would be good candidates for CO_2 storage and 2) the possible presence of fossil fuels and the exploration and production maturity of the basin. Mature sedimentary basins could be primary targets for CO_2 storage both because of their well-known characteristics and portions of the infrastructure needed for CO_2 transport and injection may already be in place. [4] Outreach and public engagement are also a critical component of a CO_2 storage project. [186] In some cases, site characterization may involve extensive field work to determine a site's suitability for a CO_2 storage project. This fieldwork might include conducting visual assessments of the community and seismic surveys, as well as drilling boreholes and test wells. If site characterization activities include these steps, then an outreach plan needs to be developed and implemented to educate the surrounding communities and stakeholders, as well as to build relationships that can be used to facilitate sharing of information during the lifetime of the project. [186]

Additionally, data acquired from site characterization are used to prepare five plans (AoR and Corrective Action Plan, Testing and Monitoring Plan, Injection Well Plugging Plan, PISC and Site Closure Plan, and Emergency and Remedial Response Plan) required for permitting a Class VI well. [164]

5.4.3 Permitting (Injection)

Permitting requirements diverge significantly depending on the end use of the CO_2 injection operation. For instance, CO_2 storage operations are required to inject under UIC Class VI well permits, and CO_2 injection for enhancing hydrocarbon recovery is mandated under UIC Class II well permits. Generally, for both types of well classes, the information gathered during site characterization is assembled into an injection permit application, a reservoir model, and the preliminary project design.

For UIC Class VI wells, the site operator must submit a UIC Class VI permit application (with the appropriate plans) to the applicable regulatory agency prior to installing and operating a well to inject CO_2. Each CO_2 injection well requires its own permit although several Class VI wells can have a common AoR. Once an injection permit is granted, an operator will drill, test, and complete the permitted injection well(s). New wireline logging, core(s), fluid samples, and wellbore seismic data acquired from the new injection well(s) are correlated with data from the submitted plans. If no major revisions in the plans are needed based on review of new data, then injection of CO_2 can be authorized. Major revisions would require re-opening the permitting process. Once injection begins, the site operator has 180 days to develop and submit the MRV plan for Subpart RR compliance. [191] Applying for a Class VI injection permit is a significant undertaking that is complex and time consuming. There can be a significant delay between the completion of site characterization and initiation of operational phases due to processing and review of injection permits. As one example, the ICCS Class VI permit process began with application submission in July 2011, but their Class VI permit was not awarded until December 2014. Injection of CO_2 did not begin until April 2017. [192] Class VI permits are issued for the operating life of the facility and PISC per 40 CFR 146.36.

Class VI operations must be able to provide financial responsibility for CO_2 storage operations. This is demonstrated during the permit application process. Financial responsibility requirements are designed to ensure that, should owners or operators fail to fulfill their obligations, funds are available to pay a third party to carry out required geologic storage activities related to closing and remediating geologic storage sites if needed, during injection or after wells are plugged, so that they do not endanger USDWs. These requirements are also designed to ensure that the private costs of geologic storage of CO_2 are not passed along to the public. [193] The financial responsibility instrument(s) that can be used as per 40 CFR 146.85 may include any of these qualifying instruments: 1) trust fund, 2) surety bond, 3) letter of credit, 4) insurance, 5) self-insurance, 6) escrow account, or 7) another instrument(s) satisfactory to EPA. The financial responsibility qualifying instrument(s) must be sufficient to cover the cost of the following components of the UIC Class VI rule:

- Corrective action (that meets the requirements of § 146.84)
- Injection well plugging (that meets the requirements of § 146.92)
- PISC and site closure (that meets the requirements of § 146.93)
- Emergency and remedial response (that meets the requirements of § 146.94

The permitting process for UIC Class II wells is less rigorous than for Class VI wells. Class II wells are ultimately overseen by state agencies where Class II primacy is granted. However, federal regulations indicate that Class II well permits, unlike Class VI well permits, can include area permits. These permits enable the permitting of multiple wells on an area basis, rather than for each well individually, provided that the permit is for injection wells in the same field, reservoir, or project.

5.4.4 Operations

The operations phase is the project phase in which active CO_2 transportation and injection occurs at the selected storage site. Information obtained during site screening and selection, as well as site characterization, and the engineering requirements dictated by the CO_2 source, provide a technical basis for operational planning. The preliminary activities of this phase can include operational planning, site preparation, drilling monitoring well(s) as needed, and facility construction. Some of this work may be done during the permitting phase when the injection wells are drilled and tested. During injection operations, activities include monitoring and collecting operational data per the approved plans. [164]

Monitoring is a major component of CO_2 injection operations. It is during the operational phase that the bulk of the MVA activities occurs, the most critical is tracking the movement of the underground CO_2 plume and pressure front to ensure safe operating conditions, detecting leaks, and ensuring that USDWs are not contaminated by brine or CO_2. [194] Plume monitoring will determine whether the injected CO_2 is behaving as predicted. If not, modifications to the operating procedure may be required. If a leak is detected, remedial action may be necessary. A detailed risk assessment and analysis performed early in the project should identify appropriate actions to mitigate various leak scenarios should a leak occur, either during operation or after project closure. Several mandatory monitoring requirements under EPA's UIC Program (see Section 3.1.3) dictate MVA approaches for projects and are normally established before an injection permit is issued.

Planning for operations will be different depending on the purpose of the selected site—if it is for geologic storage or for CO_2 EOR. An overview of the operations phase for CO_2 storage in saline formations is provided in the next subsection.

5.4.4.1 Saline Storage Operations

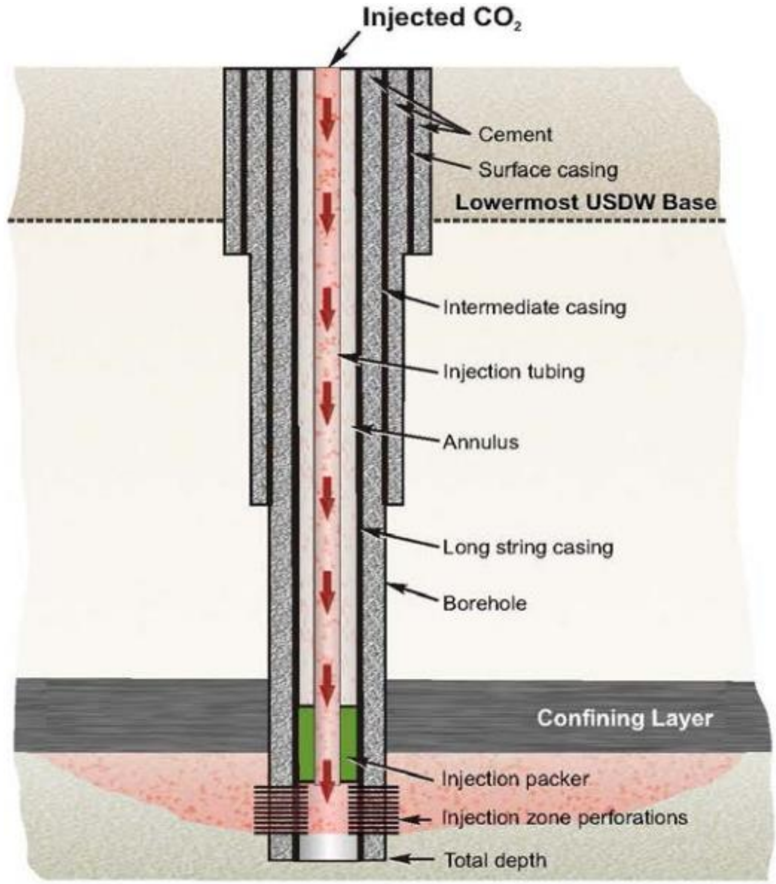
Storage of CO_2 in saline reservoirs is an attractive option for CCS operations. For instance, the storage resource potential for saline reservoirs is estimated to be substantial. [14] Additionally, saline storage capacity potential is much greater than that for depleted oil and gas reservoirs, and saline reservoirs are also widespread geographically, providing more opportunities for CO_2 storage from many emission sources. [14] The preservation of caprock integrity, storage permanence, and pressure management within the storage reservoir are key considerations for CO_2 storage in saline-bearing formations. [195] In addition, management of brine fluids in the reservoir could play a key role in saline storage operations due to possible pressure increase(s) within the formation during CO_2 injection. Brine extraction could reduce the formation pressure, but additional production wells and fluid handling at the surface will be needed (and either a follow-on water treatment or disposal option). Generally, the resultant pressure front within the saline storage reservoir extends much further than the CO_2 plume, creating an expanded area in which the risk to seal integrity (creating fractures or activating faults) and displacement of formation brine increases. To quantify the risk of CO_2 leakage, it is necessary to determine the extent of the CO_2 plume and pressure front and assess potential leakage pathways for CO_2 or brine. Monitoring the magnitude and location of pressure build-up in the reservoir is important for operators and regulators evaluating pressure induced risks. Additionally, CO_2 storage operations revolve around one-way injection of CO_2; this approach significantly differs from CO_2 EOR, in which periods of cyclical injection, production CO_2 recycle, and reinjection of CO_2 occurs.

Operators of Class VI wells are required to take diligent action and follow approved plans during the operational phase of a CO_2 storage project to ensure safe and effective operations. For instance, UIC Class VI regulations require operators to not exceed injection pressure of 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures. Only during permitted stimulation of the injection zone(s) can an operator exceed 90 percent of the fracture pressure. Other safeguards include performance standards for well construction to ensure that CO_2 cannot move between formations along the wellbore. For instance, all well materials must be compatible with fluids in which the materials may be expected to come into contact (e.g., CO_2, formation brines) and must meet or exceed standards developed for such materials by API, American Society for

Testing and Materials International, or other comparable standards deemed acceptable by EPA. Additional well construction requirements include the following (Exhibit 5-5 below is a schematic of a typical Class VI well [not to scale] and highlights the components as they are described in the bullets below):

- Filling the well annulus between the tubing and the long string casing with a non-corrosive fluid [40 CFR 146.88(c)]
- Surface casing must extend through the base of the lowermost USDW and be cemented to the surface using single or multiple strings of casing and cement [40 CFR 146.86(b)(2)]
- At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages [40 CFR 146.86(b)(3)]
- Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by API, American Society for Testing and Materials International, or other comparable standards acceptable by EPA [40 CFR 146.86(c)(1)]
- All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval [40 CFR 146.86(c)(2)]
- Install and use 1) continuous recording devices to monitor the injection pressure, the rate, volume and/or mass, and temperature of the CO_2 stream, the pressure on the annulus between the tubing and the long string casing, and annulus fluid volume [40 CFR 146.88(e)(1)]; 2) for onshore wells, alarms and automatic surface shut-off systems or, down-hole shut-off systems (e.g., automatic shut-off, check valves), or other mechanical devices that provide equivalent protection [40 CFR 146.88(e)(2)]; and 3) for offshore wells within State territorial waters, alarms and automatic down-hole shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit [40 CFR 146.88(e)(3)]

Exhibit 5-5. Schematic example of a UIC Class VI injection well featuring key well components and relation to USDWs, confining layer, and injection zone [11]



Source: U.S. EPA

Commercial-scale CO_2 injection projects are anticipated to operate for upwards of 30 to possibly 60 years—in some cases, even longer depending on the duration of PISC. [164] It is expected that many of the baseline project conditions may change dramatically over the project lifetime as a result of injection. Monitoring, analysis of collected data, and reservoir modeling are needed throughout a project's operational life to understand the impacts of injection. For CO_2 injection and storage using a Class VI well, the following operational phase monitoring and subsequent modeling is required:

- Tests of both continuous and periodic well mechanical integrity [40 CFR 146.89]
- Analysis of the CO_2 stream with sufficient frequency to yield data representative of its chemical and physical characteristics [40 CFR 146.90(a)]
- Installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added [40 CFR 146.90(b)]

- Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis [40 CFR 146.90(c)]
- Periodic monitoring of the groundwater quality and geochemical changes above the confining zone(s) [40 CFR 146.90(d)]
- Testing and monitoring to track the extent of the CO_2 plume and the presence or absence of elevated pressure by using: 1) direct methods in the injection zone(s) [40 CFR 146.90(g)(1)] and 2) indirect methods (like seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools) [40 CFR 146.90(g)(2)]
- Delineation of the AoR at a frequency no less than every five years during operation [40 CFR 146.84(b)(2)(i)]. This includes predicting the projected lateral and vertical migration of the CO_2 plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed period as determined by EPA. The model would be built on existing site characterization, monitoring, and operational data [40 CFR 146.84(c)(1)]

5.4.5 Closure of Injection Operations

Most site closure activities will take place once all injection has ceased. Site closure activities could include decommissioning surface equipment (associated with injection), plugging injection wells, restoring the site, and preparing and submitting site closure reports. Surface facilities not associated with PISC may be removed, including buildings, access roads and parking areas, sidewalks, underground electric and telecommunication facilities, and fencing. In addition, the land could be reclaimed to a pre-development state or for other uses (like agriculture). [164] [165] Site closure, as described here, relates specifically to the cessation of injection operations and preparation of the site for post-injection monitoring and site care. The closure requirements could vary depending on the specific UIC well class (Exhibit 3-2). For instance, for Class VI wells, regulatory requirements suggest that the injection well would be flushed, the bottom-hole reservoir pressure after injection determined, and a final external MIT performed. Additionally, monitoring wells must be plugged in a fashion that prohibits fluid movement from endangering USDWs.

5.4.6 Post-Injection Site Care and Site Closure

The PISC phase comprises preparing the CO_2 storage site for long-term monitoring per the approved plan leading to the decommissioning and closure of the site. In general, the PISC phase of a project is intended to ensure the safety of USDWs, that the stored CO_2 plume presents a non-endangerment. Monitoring and modeling as well as tracking the decrease in pressure of the CO_2 plume are critical to establish non-endangerment. [196] UIC regulations indicate that the owner or operator shall continue to conduct PISC monitoring for the duration of the permit-approved timeframe, 50 years (Exhibit 3-2). The operator can apply for the duration of PISC to be reduced upon application of the Class VI permit and again following cessation of injection operations prior to PISC. Even with a reduced period for PISC, non-endangerment can still be demonstrated. Once non-endangerment is established, the site can be closed. All wells used for monitoring are plugged, and surface monitoring equipment is removed. All well sites and surface equipment sites are reclaimed, and the permit is released.

5.5 THE COST TO IMPLEMENT CO_2 STORAGE

The potential costs of commercial-scale CCS are still not fully understood, particularly from a fully integrated (capture, transportation, and storage) perspective. [169] The challenge stems mainly from estimating storage costs, which is not a simple or straightforward process. [197] A typical storage project involves the time-intensive steps of site screening, site selection and characterization, permitting and construction, operations, and PISC and site closure. [198] Therefore, most CCS cost studies typically exclude, or assign a fixed constant for storage cost. [198] [199] However, such a simplistic approach ignores the large variation in storage cost due to differences in operational monitoring and reservoir quality. [197] [200]

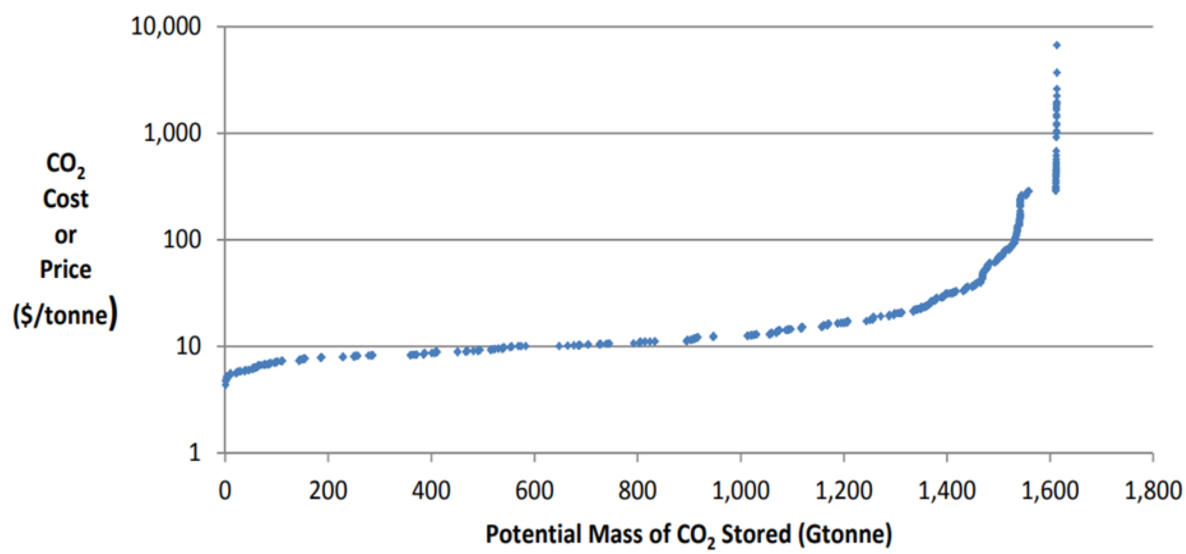
The geologic heterogeneity of storage formation characteristics is the major driver of site specific cost variability). [201] Reservoir depth, thickness, permeability, and porosity affect injectivity, storage capacity, and formation pressures, which, along with structural setting, impact the aerial extent of the CO_2 plume, one of the primary cost drivers of storage costs. [202] [203] A smaller plume footprint, particularly when physically constrained by dome or anticlinal structures, lowers cost by reducing the number of wells needed for monitoring or injection, permit requirements, and the need for surface access. [191] In general, the lowest storage costs, both for drilling and monitoring, will be associated with formations that have the highest storage capacity, even if those reservoirs are further away from a CO_2-generating source. [197] [201] [204] Typically, these are relatively thick, shallow (but still at a depth where CO_2 remains in a supercritical state) and highly permeable formations. [4]

The impact of regulation on cost, including monitoring requirements, liability and long-term management of CCS projects, remains uncertain. [199] EPA's UIC Program requires Class VI well owners or operators to demonstrate and maintain financial responsibility to cover the cost of corrective action, well plugging, emergency and remedial response, and PISC activities. [5] Since the PISC stages could last more than 50 years, the selection of a financial instrument and its associated parameters like pay-in period, tax rate, and administrative fee could have a drastic impact on total storage cost.

NETL developed a FE/NETL CO_2 Saline Storage Cost Model (Storage Cost Model), which is used to estimate the revenues and cost associated with implementing a saline storage project (does not estimate costs for CO_2 capture or transport). The model is built by utilizing scientific and engineering principles that are influenced by subsurface injection. It is based on ensuring compliance with the UIC Class VI regulations developed by EPA for constructing, operating, permitting, and closing injection wells used to place CO_2 underground for storage. The model contains geographical and geological data for 226 reservoirs across 48 states in the United States to simulate the CO_2 first-year break-even cost based on currently available technology. [191] Reservoir data is sourced from the NATCARB database. Storage reservoirs can be modeled under three structural settings: dome, anticline, and regional dip. With the baseline assumption

[191], injecting 3.2 million tonnes (Mt) of CO_2 for 30 years, the lowest CO_2 break-even price is $4.30/tonne and the highest is over $1,000/tonne in 2011 dollars (2011$), based on currently available technology. Exhibit 5-6 presents the cost-supply curve from the NETL baseline study. [191] The y-axis is the first-year break-even price of CO_2 ($/tonne) in 2011$. The x-axis is the cumulative potential CO_2 storage capacity for a given price (gigatonnes [Gt or Gtonne]). The cost curve represents the potential cumulative mass of CO_2 that can theoretically be stored in the 226 storage reservoirs under the corresponding per tonne price. The potential storage cost supply curve shows an upsloping to vertical trend on the right-hand side indicating poor quality, high cost storage reservoirs. [198] The left-hand side of the curve shows that approximately 550 Gt of potential storage capacity is available for under $10/tonne and approximately 1,350 Gt potential storage capacity is available for under $25/tonne. Both potential storage capacity numbers exceed the estimation by the Energy Information Administration that if 90 percent of all the CO_2 emitted from power plants and stationary industrial sources over the next 100 years were captured, the mass of captured CO_2 would be approximately 315 Gt. [205]

Exhibit 5-6. Cost supply curve for baseline case [191]

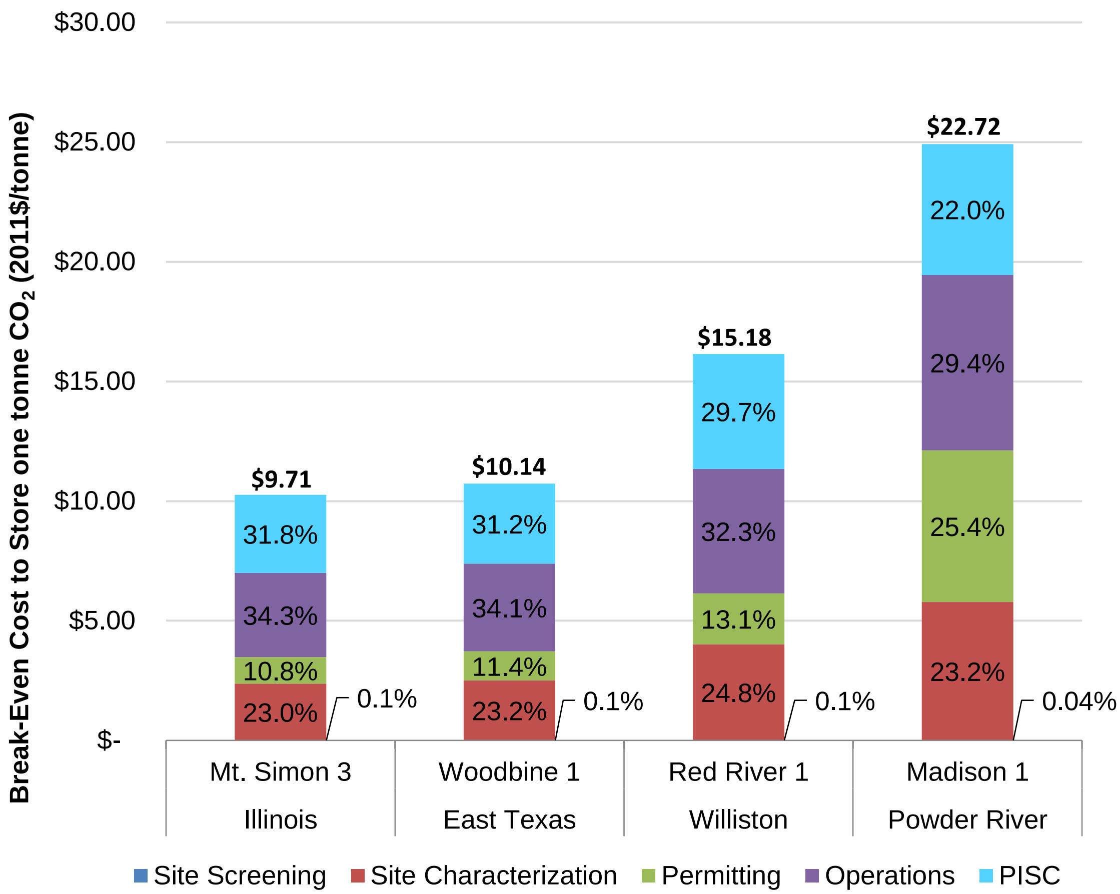


Another NETL study estimated the storage cost variability in four different basins: Illinois, East Texas, Williston, and Powder River, using region specific results from the Storage Cost Model. [202] The study established three scenarios to model a low-cost case, base case, and high-cost case to account for the variation in geologic characteristics of multiple formations and their reservoir subsets in each basin. The model parameters of trust fund growth rate, monitoring well spaces, PISC length, and project stage durations were changed between the three scenarios, but remained identical between basins. The results of this study, for example, show that the Mt. Simon reservoirs in the Illinois Basin are the low-cost providers with low, base, and high cost case estimates at $5.61/tonne, $9.71/tonne, and $18.99/tonne in 2011$, respectively.

Exhibit 5-7 shows the break out of storage costs (in 2011$/tonne) by project stage (site screening, site selection and characterization, permitting and construction, operations, and PISC) for one reservoir in each of the four basins. Cost breakouts presented were for the regional dip structural setting for each reservoir and the reservoir combination that provides

CO_2 storage resource potential at 25 Gt. Costs for site characterization, operations, and PISC (which are impacted by the size of the CO_2 plume) were similar for the Mt. Simon 3 reservoir in the Illinois Basin and the Woodbine 1 reservoir in the East Texas Basin, but increased for the Red River 1 reservoir in the Willison Basin and Madison 1 reservoir in the Powder River Basin due to an increasing plume size and number of monitoring wells required. The greatest overall cost contribution difference between reservoirs is related to permitting, which increases when more injection wells are needed to meet targeted injection rates (influenced strongly by permeability and reservoir thickness). For instance, permitting costs are the highest for the Madison 1 reservoir because of the relative need of more injection wells compared to the other reservoirs.

Exhibit 5-7. CO_2 break-even price to store one tonne of CO_2 by project stage for reservoirs at 25 Gt for base case (regional dip structure) [202]



As noted, estimating storage costs is not a straightforward process and is highly dependent on variations in reservoir geology. However, since CO_2 capture is fixed to the source, storage is an important CCS variable, and is required to achieve a minimum integrated CCS cost. Additionally, it has been shown that the unit cost of storage decreases with increasing mass of CO_2 stored. [204]

5.6 Comparison and Contrast of Geologic CO_2 Storage with CO_2 EOR Operations

The content presented in previous sections of this report show that CO_2 EOR production using UIC Class II wells is a quality analog that can be used to help address technical and policy-related questions concerning CO_2 geologic storage—more specifically focused on long-term CO_2 storage in saline-bearing formations using UIC Class VI wells. In the context of this report, analogs are identified as examples or case studies that help identify features that are likely to be effective for CO_2 storage and those that should be avoided. In addition, analogs help to compare the two different industries—in this case, CO_2 EOR operations and CO_2 geologic storage operations using UIC Class VI wells.

This section presents a side-by-side comparison of major synergistic features (such as governing regulations, formation types used, operational and monitoring practices, leakage risks, and other) between CO_2 EOR under UIC Class II wells as an analog to CO_2 storage using UIC Class VI wells. In general, CO_2 EOR is a vital component of U.S. oil production and has been in practice in the United States for over 40 years. As a result, there is considerable experience in injecting CO_2 into the subsurface. This experience has proved and will continue to prove valuable in developing future CCS projects in depleted oil and gas reservoirs, as well as saline-bearing formations. For instance, CO_2 EOR technology and equipment needs parallel those needed for geologic storage of CO_2 into saline-bearing formations, with similar surface infrastructure and wells, similar handling of supercritical CO_2, and comparable subsurface simulation and characterization tools (like well logs, seismic surveys, petrophysical analysis). [36]

There are several significant similarities between Class II and Class VI well classes; most obviously, they share the same regulating oversight body, EPA's UIC Program. UIC regulations ultimately are intended to assure that injection activities will not endanger USDWs (as per 40 CFR 144.12). Specific regulations (based on 40 CFR 144, 146, and 148, not necessarily accounting for all state-level or tribal region primacy variation and specifics) vary from well class to well class to ensure protection of USDWs based on the injection activity associated with a given well class; [76] however, there are substantial similarities and overlap for several requirements across both well types (Exhibit 3-2). From an operational standpoint, both practices include underground storage of a buoyant fluid (relative to the native fluid), the need for an adequately thick caprock (ideally with a secondary caprock above the primary seal to ensure long-term containment), enough pore space for sufficient storage capacity (in the case of EOR, pore space that enables ample HCPVs of residual oil), and sufficient permeability for effective injectivity. For both well classes, injection wells must be properly designed, installed, monitored, and maintained; and abandoned wells in and near the project area must be located and properly plugged. [4] Careful control of injection pressure and final reservoir pressure based on geomechanical properties is necessary under both well classes to avoid damage to the caprock. Most of these operational and geologic parameters can be properly identified through geologic characterization and selection of storage sites. [19]

While prominent similarities exist between the two well types, there are substantial differences between the two practices. One example is the differences in the overall intent of the two practices. While the physical state of the injected CO_2 is inherently the same between practices, the overall end goal is not. In EOR the objective is to maximize oil production while minimizing CO_2 usage, since CO_2 is typically purchased, and minimizing CO_2 usage minimizes costs. In CO_2 storage, on the other hand, the objective is to maximize CO_2 storage. [2] Secondly, the varying levels of commercial application and experience of each practice is drastically different. CO_2 EOR is a well commercialized industry, whereas CO_2 storage in saline-bearing formations is still a relatively new concept that has been undergoing pilot and early commercial-scale testing. Also, the robustness and maturity of the regulatory frameworks governing the two operations is substantially different even though both practices are regulated by EPA's UIC Program. As described in Section 3.1, UIC Class VI wells are bound to more rigorous requirements than UIC Class II wells.

Beyond its potential to augment U.S. oil production, CO_2 EOR also gets significant attention by CCS-related stakeholders because it inherently retains (i.e., stores or sequesters) CO_2 as part of the miscibility process and subsequent movement of CO_2 and miscible oil through the reservoir. For instance, many believe that CO_2 EOR reservoirs can provide early CCS targets since they have proven reservoir injectivity, provide known traps that have held hydrocarbons in place over geologic time-scales, likely have known capacity, enable management of CO_2 plumes in the subsurface, provide infrastructure, may offer additional stacked storage potential, are advantageous for monitoring because of available well infrastructure, are well characterized, and have extensive pre-injection data. [36] Furthermore, CO_2 EOR can add value by maximizing oil recovery while at the same time offering a bridge towards managing CO_2 emissions from anthropogenic sources. CO_2 EOR effectively reduces the cost of storing CO_2 with revenues from the sale of CO_2 to EOR operators. [2] While many experts look to geologic storage as one of the best management approaches for dealing with CO_2 emissions from anthropogenic sources, [2] [4] [17] CO_2 EOR could offer the critical first step. The CO_2 EOR industry is an industry with a proven track record of safely injecting CO_2 into geologic formations. However, most of the CO_2 used in EOR comes from naturally-occurring underground sources and does not represent a net reduction in CO_2 emissions. The integration of CCS with CO_2 EOR offers the potential to significantly alter this situation.

The similarities and differences are worth mentioning and have been compared in detail below. Exhibit 5-8 is a tabularized summary of the major synergistic features for both UIC well types for an easy side-by-side comparison.

Exhibit 5-8. Comparison between key items pertaining to CO_2 EOR using UIC Class II wells and CO_2 storage in saline-bearing formations using UIC Class VI wells

Item	EOR using CO_2 (UIC Class II Wells)	Saline CO_2 Storage (UIC Class VI Wells)
Purpose	Increase hydrocarbon recovery (tertiary) with the use of natural or anthropogenic CO_2 Reduce carbon emissions to atmosphere from anthropogenic CO_2 sources	Reduce CO_2 emissions into the atmosphere through injection of captured CO_2 into deep, confined rock formations for long-term storage
Technology Inception	Early-1970s	Mid-1990s Class VI well promulgated: 2010
Number of Active Fields or Projects	Approximately 136 active – United States only [43]	Three active projects in the United States
Active Well Count [95]	UIC Class II Recovery Wells – 143,587 UIC Class II Disposal Wells – 36,757 UIC Class II Wells noted as Other - 66	2
Formation Types	Depleted oil and gas reservoirs Residual oil zones	Saline-bearing formations
Reservoir Fluid Prior to Injection	Oil, gas, and water	Water greater than 10,000 TDS
Injected Fluid Phase	Supercritical CO_2	Supercritical CO_2
Injection Management	CO_2 injection, production, and recycle	One-way continuous CO_2 injection
Prominent Regulations	SDWA UIC Class II: ▪ 40 CFR 144 Subpart A ▪ 40 CFR 146 Subpart C Clean Air Act Subpart UU	SDWA UIC Class VI: ▪ 40 CFR 144 Subpart A ▪ 40 CFR 146 Subpart H Clean Air Act Subpart RR
Regional Prominence	Reference Exhibit B-4 for oil and gas reservoirs	Reference Exhibit 5-3
Potential National CO_2 Storage Capacity	Depleted oil and gas reservoirs, estimated: 186 – 232 billion tonnes	Saline-bearing formations, estimated: 2,379 – 21,633 billion tonnes
Injection Well Design Considerations	Cased and cemented to prevent movement of fluids into or between USDWs (based on state requirements where state primacy is established) Injection formation fluid pressure, estimated fracture pressure, and physical/chemical characteristics of the	Well materials compatible with fluids present in the subsurface Surface casing must extend through base of lowermost USDW and be cemented to the surface

Item	EOR using CO_2 (UIC Class II Wells)	Saline CO_2 Storage (UIC Class VI Wells)
	injection zone must be understood to inform proper well design Periodic observation of injection pressure, flow rate, cumulative injection volume Injection pressure limited to 80 percent of fracture pressure (for most states)	At least one long string casing with centralizers from surface to injection zone and cemented back to the surface Tubing and packer required to inject CO_2 Annulus between tubing and long string casing must be filled with a non-corrosive fluid Continuous recording devices needed to monitor pressures, flowrate, volume/mass, and CO_2 stream temperature Alarms and shut-off systems may be required Injection pressure limited to 90 percent of fracture pressure
Number of Injection Wells	Considerable number of wells (often pattern based [5-spot, 9-spot, etc.]) to maximize CO_2 sweep efficiency and hydrocarbon production	Injection well count tied to mass of captured CO_2 requiring storage injection. Spare injection capacity needed to allow well shut-in for maintenance
Prominent CO_2 Containment Mechanism	Capillary trapping within reservoir	Structural trapping, stratigraphic trapping
Leakage Risks	Wellbore failures Surface equipment leakage	Wellbore failures Caprock integrity – faults and fractures
Pressure Build-up Risks [36]	Pressure management (i.e., intentionally increasing reservoir pressure via CO_2 injection) a key option for CO_2 EOR	Potential reservoir pressure increases over large areas expected. Pressure management approaches (like extracted reservoir water) could be implemented
Commercial-scale Examples	Weyburn-Midale Project – Canada SACROC – West Texas Farnsworth Unit – West Texas West Hastings Unit – Texas Gulf Coast	IBDP – Illinois ICCS – Illinois FutureGen 2.0 – Illinois (canceled) Sumner County Kansas Small-scale Field Test – Kansas (canceled)

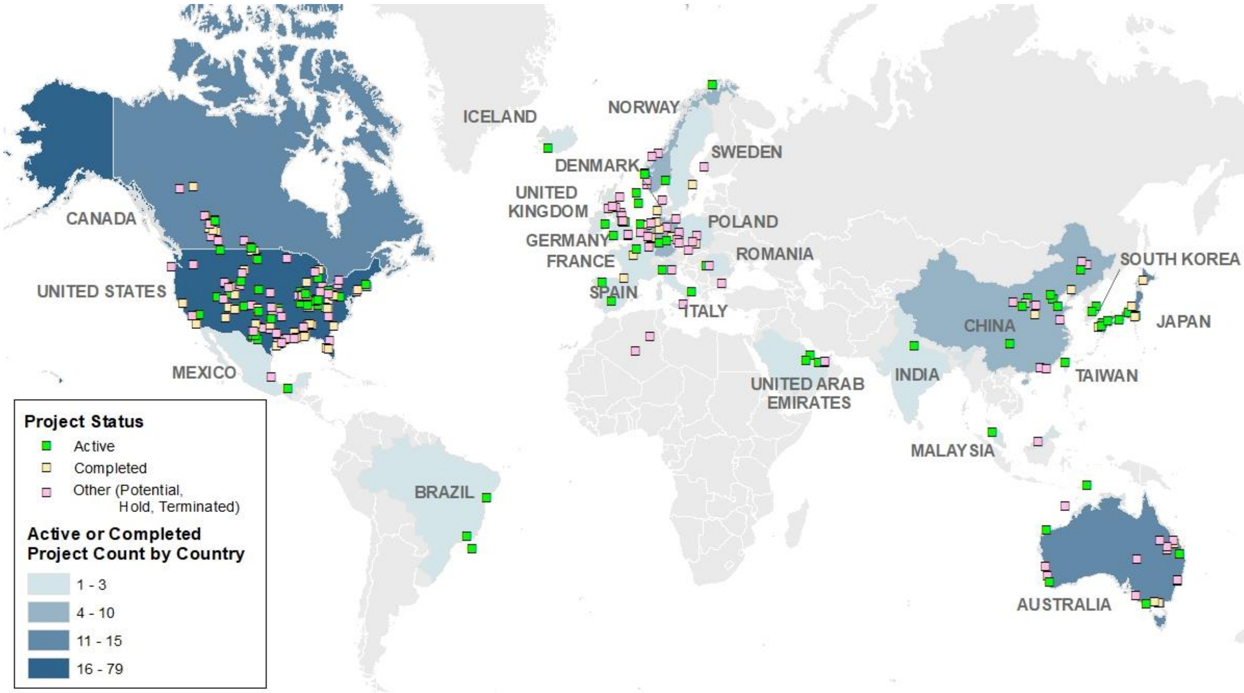
A case study that compares capacity between a real-world (on a mass basis) CO_2 EOR project and a potential CO_2 storage operation would be a useful way to comparatively evaluate the relative size of each operation. For instance, a simple approach can be used to estimate the amount or rate of CO_2 that could be stored to a comparable volume of CO_2 used at a commercial-scale CO_2 EOR project like SACROC.

Contek Solutions prepared a report titled *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology* for API in 2007. [1] This report indicated that the SACROC field has a CO_2 handling capacity (which is assumed to accommodate injection, recycle, and transport—not exclusive to injection only) of more than 0.6 billion cubic feet per day. Assuming the 0.6 billion cubic feet per day (219 billion cubic feet per year) handling volume, the SACROC field handles roughly 11.4 Mt/yr of CO_2 per year, which is a substantial mass of CO_2. This is roughly the annual rate of CO_2 injection needed to store the captured emissions from three 550-megawatt supercritical pulverized coal power plants. [54] From a comparative perspective, UIC Class VI permits for pilot studies like the FutureGen 2.0 project (which was canceled in 2016) was approved to inject 22 Mt of CO_2 over a 20-year project life (roughly 1.1 Mt/yr), [174] and ICCS was approved to inject 1 Mt/yr for five years. [175] However, commercial-CO_2 storage volumes are expected to be significantly higher than those proposed at FutureGen 2.0 and at ICCS.

5.7 Examples of Successful Demonstration of CCS Technology

As CCS technologies and research continue to advance, demonstration projects become critical for validating that CO_2 capture, transport, injection, and storage can be achieved safely and effectively. Successful demonstration and deployment of CCS technologies can contribute toward building confidence and reducing costs through new innovations and advances in capture, storage, and monitoring technology and protocols. In 2018, NETL had identified over 300 existing, planned, or recently-completed CCS-related projects (ranging from pilot testing to commercial-scale) across the globe (Exhibit 5-9). [6] The Global CCS Institute indicates that 37 CCS projects across the globe are of “large-scale;” 17 of which are currently in operation, while the others are under construction or in development. [7] CCS has and continues to be successfully demonstrated throughout the world. As R&D activities continue to advance CCS toward commercialization, demonstration projects that implement and validate safe and effective CO_2 injection and storage technologies become critically important. This section highlights several CCS-related projects supported by DOE in saline-bearing formations in the United States. Additionally, these projects are injecting, or are expected to inject, CO_2 into the subsurface under the UIC Class VI regulatory setting.

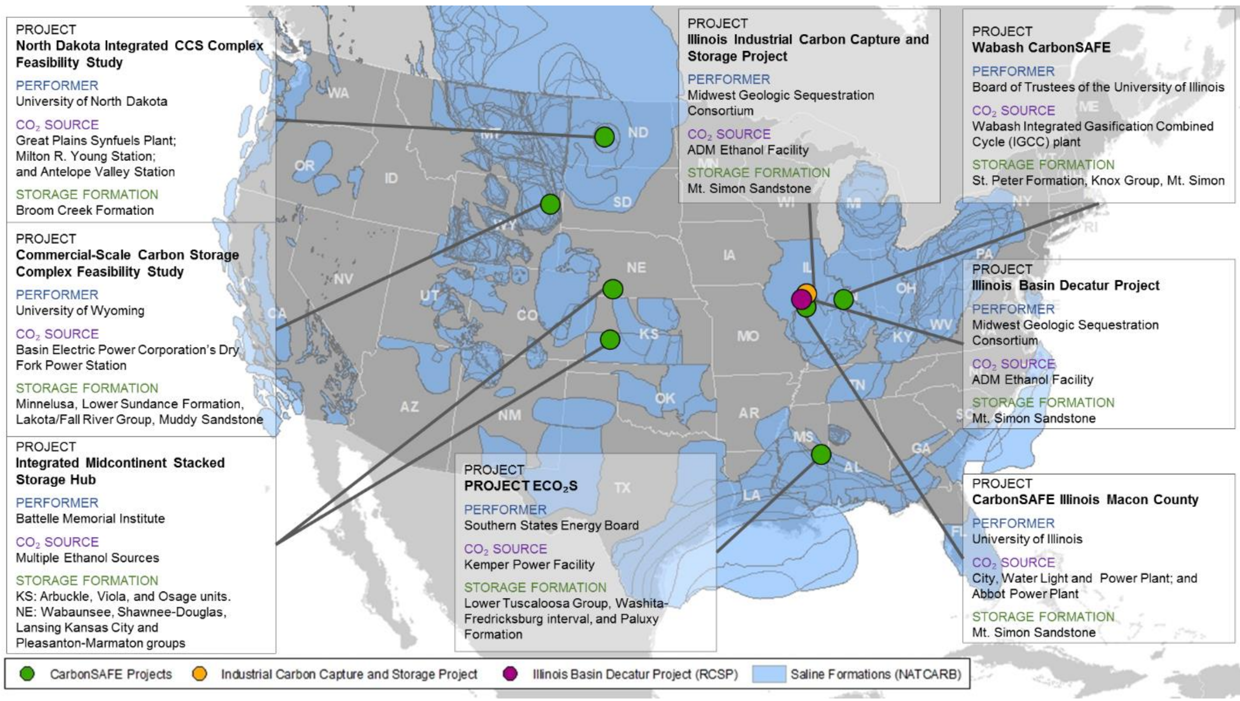
Exhibit 5-9. Map of active or recently completed CCS-related projects worldwide [6]



5.7.1 DOE-Supported Examples in the United States

DOE supports a portfolio of small- and large-scale CO_2 storage field projects with the goal of improving the effectiveness of CCS technology and reducing the cost of implementation in preparation for widespread commercial deployment. For example, the RCSP Initiative managed by NETL implements both small- and large-scale CO_2 storage field projects. They comprise of seven public/private partnerships, including more than 400 organizations, and spans 43 U.S. states and four Canadian provinces. [15] [173] [177] The RCSP Initiative is implemented in three phases: 1) Characterization Phase, 2) Validation Phase (small-scale field projects; 100,000 tonnes total for saline), and 3) Development Phase (large-scale field projects, greater than 1,000,000 tonnes). Field projects occur across different depositional environments and formation types and involve integrated system testing and validation of critical components, including geologic storage, simulation and risk assessment, and MVA technologies. [14] In addition, for over 25 years DOE's Major Demonstration Program has been demonstrating large-scale integration of clean coal technologies (including CCS) to facilitate their deployment in the commercial marketplace. This program is currently collaborating with industry in cost sharing arrangements that are demonstrating the next generation of technologies that can capture CO_2 emissions from industrial and power-generating sources and either store those emissions or beneficially reuse them. Projects in this area have typically progressed beyond the R&D stage to a scale that can be readily replicated and deployed into commercial practice within the industry. [206] The field projects supported by DOE enable 1) direct observations of the behavior of CO_2 in the subsurface, enabling improved confidence that CO_2 can be injected and stored safely; 2) demonstration of technologies that are inherently in first-of-a-kind projects; and 3) government and industry cooperation fostering environmentally and economically sustainable energy systems. [15] [17] [206] Examples of the more recent DOE-supported large-scale CO_2 capture and storage projects utilizing saline-bearing formations as storage options are highlighted in the subsequent subsections. Additionally, the emerging CarbonSAFE initiative is featured to emphasize the next wave of large-scale CO_2 storage investigation in saline-bearing formations (Exhibit 5-10). Overall, results obtained from these efforts will provide the foundation for validating that CCS technologies can be commercially deployed and monitored throughout the United States.

Exhibit 5-10. U.S. map featuring the locations and information pertaining to DOE-supported capture and storage projects, as well as proximity to saline-bearing formations attained from NATCARB [207]



5.7.1.1 Illinois Basin Decatur Project (IBDP)

The IBDP is located at the Archer Daniels Midland Company (ADM) industrial facility in Decatur, Illinois. The project began in 2007. The CO_2 source of the project is ADM's corn wet milling plant with ethanol production and is typically 99 percent+ pure. This project is a large-scale, saline reservoir storage test targeting 1 Mt of CO_2 injection over a three-year operation period. The project injected 1,000 tonnes per day between November 17, 2011 and November 26, 2014. A total of 999,215 tonnes of CO_2 was stored when injection ceased. [208] The IBDP injection well operated under a Class I non-hazardous well permit issued by the Illinois EPA (Region 5), but utilized injection well design and construction, as well as operational monitoring procedures that fulfilled the requirements of a UIC Class VI permit. Injection was completed under the Class I well permit issued by EPA. However, the IBDP team had agreed to apply for a Class VI permit, which was issued in February 2015. [192]

The CO_2 was injected into the Mt. Simon sandstone at a total depth of 7,236 ft. Mt. Simon thickness at the IBDP site is more than 1,500 ft. [209] Prior to CO_2 injection, baseline values of geophysical and geochemical properties were established as reference for monitoring each stage of the project to gauge reservoir response resulting from CO_2 injection. [208] This project demonstrated that the Mt. Simon is a viable and important resource for deep saline storage. It has favorable porosity and permeability [208] and is overlain by a thick seal, 500 ft of the Eau Claire.

The project began its ten-year PISC stage under the IBDP Class VI UIC permit. The project has an extensive MVA, and its assessment program focused on the project site and critical locations in the surrounding area to evaluate potential impacts of injection. The PISC MVA plan includes 3-D seismic, 3-D vertical seismic profile, soil flux and atmospheric monitoring, shallow groundwater monitoring, and deep subsurface monitoring and fluid sampling. [210] [211]

5.7.1.2 Illinois Industrial Carbon Capture and Storage Project (ICCS)

The ICCS expands the operations in the IBDP to a commercial scale. [208] This project aims at injecting 5 Mt of CO_2 over three years at 3,000 tonnes per day injection rate. CO_2 is also sourced from the ADM Decatur plant (same CO_2 source as the IBDP) and is sent via a 24-inch diameter, 1,500 ft long pipeline to a dehydration/compression facility, which has a design capacity up to 2,000 tonnes of CO_2 per day. The transport pipeline from the compression facility to the injection wellhead is an eight-inch diameter, one-mile long pipeline. The CO_2 is injected into the lower part of the Mt. Simon Formation at around 7,000 ft. ICCS submitted their Class VI permits in July 2011. EPA issued the Final Class VI permit for underground CO_2 injection in December 2014. The project began injecting CO_2 in April 2017. Since then, 310,000 tonnes of CO_2 has been stored in the Mt. Simon sandstone saline reservoir. [212] [213]

5.7.1.3 Carbon Storage Assurance Facility Enterprise (CarbonSAFE)

CarbonSAFE is an effort to develop integrated CCS storage complexes, constructed and permitted for operation in the 2025 timeframe. [214] This initiative has a series of sequential phases of development: Integrated CCS Pre-Feasibility, Storage Complex Feasibility, Site Characterization and Permitting, and Construction. [215] Although significant CCS technology advancements have been made in recent years, especially through DOE's RCSPs, key gaps in experience and knowledge must be addressed before CCS can be publicly considered as "business as usual" for CO_2 sources. Due to lack of immediate economic incentives, there is not much effort by the private sectors to identify and certify suitable storage formations capable of storing commercial-scale (50+ Mt) volumes of CO_2.

DOE released the funding opportunity announcements for Phase I (Integrated CCS Pre-Feasibility) and Phase II (Storage Complex Feasibility) seeking cost-shared projects that will determine the feasibility of developing onshore and/or offshore geologic storage complexes capable of cumulatively accepting commercial-scale volumes of CO_2. Six projects were selected under Phase II for more than $40 million. These projects are beyond the pre-screening maturity and will perform the initial characterization of a storage complex identified as having high potential and will help inform the characterization and permitting of a commercial-scale complex with at least one storage site—ultimately demonstrating the potential for safe and secure storage in time for the anticipated deployment of transformative carbon capture technologies in the 2025 time-frame. They will also establish the complex's feasibility for commercial storage (50+ Mt CO_2). The objectives of Phase II build upon the pre-feasibility work under CarbonSAFE that focuses on one or multiple specific reservoirs within the defined storage complex and comprises data collection; geologic analysis; identification of contractual and regulatory requirements and plans to satisfy them; subsurface modeling to support geologic characterization, risk assessment, and monitoring; and public outreach. The Phase II projects and a brief description of each is shown below: [214] [216]

- Southern States Energy Board (Norcross, Georgia) — The Southern States Energy Board will establish a commercial-scale CO_2 geologic storage complex (Project ECO2S) adjacent to the Mississippi Power Company Kemper County Energy Facility. The project will involve optimizing CO_2 storage efficiency, modeling the fate of injected CO_2, and establishing residual CO_2 saturations.
- University of North Dakota (Grand Forks, North Dakota) — The University of North Dakota will determine the feasibility of developing a commercial-scale CO_2 geologic storage complex in central North Dakota. The project objectives include evaluating two project study areas, each with ideal geologic storage complexes located adjacent to separate coal-fired facilities. One site near the Antelope Valley Station facility has readily available CO_2 and an existing CO_2 pipeline. A candidate site near the Milton R. Young Station facility is associated with a planned integrated CCS project with a timeline coincident with DOE's CarbonSAFE Program. Each site is bolstered by existing North Dakota pore space ownership and long-term liability laws.
- Board of Trustees of the University of Illinois (Champaign, Illinois) — The University of Illinois will establish the feasibility of a commercial-scale CO_2 geologic storage complex within the Mt. Simon (sandstone) Formation located in Macon County, Illinois, for industrial-sourced CO_2. City Water, Light and Power and the Abbott Power Plant will be evaluated as CO_2 sources. Project goals include addressing gaps in knowledge around developing large-scale geological storage complexes, improving storage capacity estimations for industry investment decision, providing input into best practices manuals from project findings, and validating the National Risk Assessment Partnership toolkits using field site data.
- Battelle Memorial Institute (Columbus, Ohio) — Battelle Memorial Institute will demonstrate the feasibility of stacked Paleozoic storage complexes at potential sites in southwest Nebraska and Kansas to safely, permanently, and economically store commercial-scale quantities of CO_2 leading to the development of a commercial-scale integrated stacked storage hub in the Midwest. The CO_2 storage hub will consist of multiple sources and storage sites by leveraging existing, proven technology for CO_2 capture and transport from ethanol sources.
- Board of Trustees of the University of Illinois (Urbana, Illinois) — The University of Illinois plans to establish the feasibility of developing a commercial-scale geological storage complex at the Quasar Syngas LLC's Wabash Integrated Gasification Combined Cycle

plant. The CO_2 will be produced from the production of ammonia at the integrated gasification combined cycle repurposed plant.

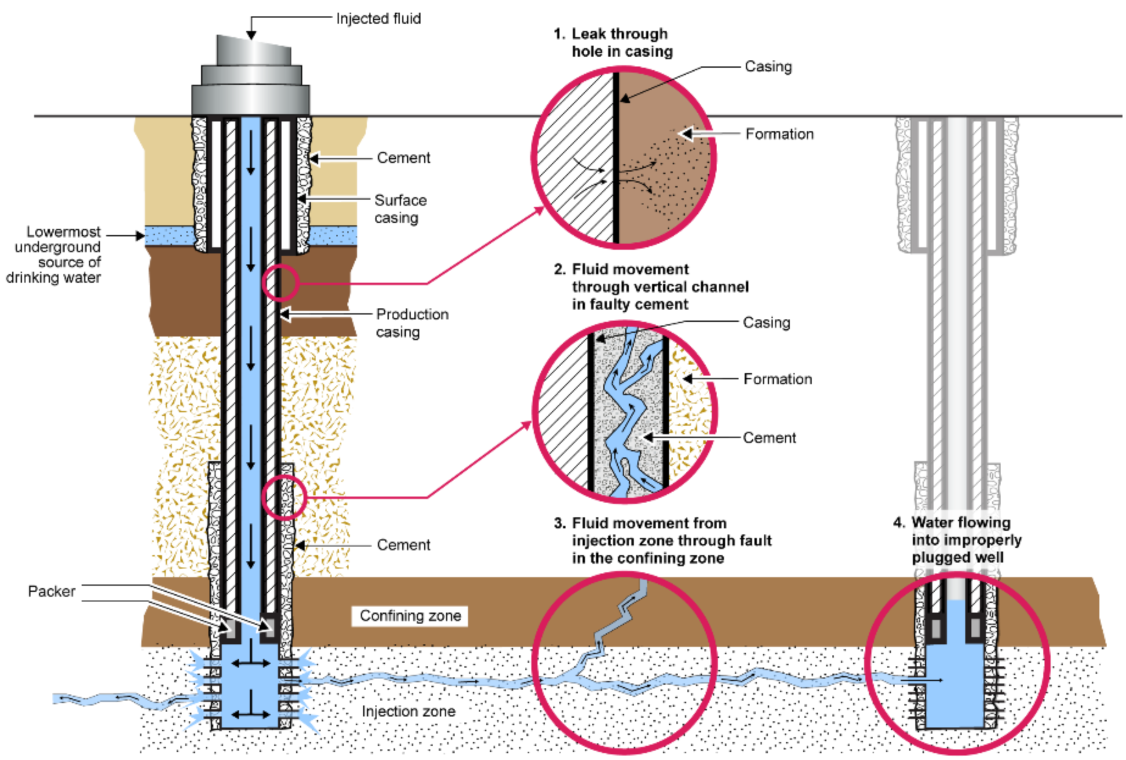
- University of Wyoming (Laramie, Wyoming) — The University of Wyoming aims to determine the feasibility of establishing a commercial-scale geological storage complex in Wyoming's Powder River Basin in the immediate vicinity of Basin Electric Power Cooperative's Dry Fork Power Station, which also houses the Wyoming Integrated Test Center (a CCS test facility). The project will include a transportation assessment of the existing CO_2 pipeline network and Wyoming Pipeline Corridor and an evaluation of suitable storage reservoirs within the immediate vicinity of the Dry Fork Power Station.

For the most part, these projects are assessing large-scale storage of CO_2 in saline bearing formations for the intent of long-term storage, which will eventually require injection under Class VI regulations. Therefore, these projects represent the next phase of CCS-related R&D on the commercial scale and should reduce the risk and cost of advanced CCS technologies, promoting sustainable use of the nation's fossil resources.

6 Class II Well Leakage Risk and Implications for Class VI Wells

Injected CO_2 as part of EOR operations can be trapped in the subsurface by permeability trapping, adsorption trapping, solubility trapping, or possibly mineralogical trapping where it is essentially stored and isolated from the atmosphere. [217] However, there are risks associated with injected CO_2 migrating away from the primary target reservoir. The combination of elevated subsurface pressure and the buoyancy forces of CO_2 relative to native fluids in place can cause the injected CO_2 to migrate laterally and upwards in the subsurface, potentially causing the injected CO_2 to reach the shallow subsurface and enter a USDW or leave the ground entirely to return to the atmosphere. [218] [219] There is also potential for the migration of native fluids (brine, oil, or gas) into other formations, including USDWs. EPA (but reported by the U.S. Government Accountability Office [154]) has identified major pathways of contamination, or ways in which fluids like CO_2 can escape the injection well or target reservoir and enter USDWs. Exhibit 6-1 shows four of the six different pathways. Another pathway that is not included in Exhibit 6-1 includes fluid movement from one part of a storage reservoir to another part that contains a drinking water source. [154]

Exhibit 6-1. Potential pathways of contamination of USDWs from UIC Class II disposal wells [154]



Source: U.S. Government Accountability Office

The leakage pathways included in Exhibit 6-1 that are most applicable to CO_2 EOR are described in further detail below:

- Fluid movement through a leakage conduit in the well's casing. The casing helps provide well stability, as well to isolate injection and/or producing intervals from other formations.
- Fluid movement between the casing and the wellbore. Such movement can occur when friction and resistance are created in the injection reservoir, and the fluid takes the path of least resistance back through conduits in the cement between the well casing and the wellbore.
- Fluid movement from an injection zone through the confining (i.e., caprock) layer.[o] When injected under pressure, fluids will travel away from the well in a lateral direction. The injection reservoir should be separated from overlying formations that contain drinking water by one or several low-permeability confining layers. However, any permeable or fractured areas in the confining layer can allow fluid movement from the injection zone into a formation that serves as a source of drinking water. This is of concern for CO_2, which is buoyant relative to native fluids (particularly brine) in the subsurface.
- Fluid movement through abandoned, orphaned, or even cemented wells that are not properly plugged. This type of fluid movement can occur when fluids injected into a formation move laterally through the formation and encounter a well that has not been properly plugged or a well that is operating but has not been properly completed. For instance, wells encountered may have potential leakage conduits through the cementing, annulus, or casing. Fluids injected under pressure will take the path of least resistance and can flow up conduits in wells and into USDWs, out of the wellbore and onto the land surface (for fluids like oil or brine), or into the atmosphere (for CO2 and natural gas). This is a significant risk in oil and gas fields where typically there are many existing wells in place.

Historically, leakage-related risks have been issues for concern in several types of injection projects, both in oil fields, for waste disposal via deep well injection, as well as for CO_2 geologic storage projects. [4] [32] [36] [39] [81] [186] Part of developing CO_2 EOR field projects safely and successfully requires that operators prepare wells for injection and production following diligent surveillance efforts to assess well integrity pre-injection. This may require work-over procedures on wells that may potentially fail to perform sufficiently (or pose a leakage risk) under elevated pressures. Site characterization efforts are also critical in determining leakage-related risks. Site characterization data (in the case of tertiary recovery, significant understanding of the subsurface should be known) should enable determination if the target reservoir and confining layers are suitable for CO_2 injection and will respond favorably under injection conditions. In the case of CO_2, corrosion issues may manifest in the presence of water; therefore, appropriate

[o] Oil and gas extraction-related activities have gained attention due to associated increases in induced seismic events, particularly in Oklahoma and Kansas. Class II injection for wastewater disposal is the primary cause of recent increases for those induced seismic events. The injection of CO_2 for the purpose of EOR has less potential to induce seismicity than disposal of wastewater (or hydraulic fracturing in shale formations) since reservoir pressure is typically maintained through the production oil (and subsequently CO_2 and water). However, disposal of excessive volumes of produced water, some of which could be derived from CO_2 EOR operations, into Class II disposal wells means that EOR can be indirectly connected to increases in induced seismicity in the United States. [32]

anti-corrosive measures may need to be in place. These are well-known approaches and best practices undertaken by operators of existing floods, [36] particularly because site operators have a strong incentive to protect CO_2 assets, as well as assure optimal operation of their CO_2 EOR floods.

Despite over 40 years of operating CO_2 EOR projects, substantial CO_2 leakage events have rarely been reported. [36] There have been no specific CO_2 monitoring and tracking requirements until recently (like Subparts RR and UU [220]) and, thus, no official mechanism for reporting leaks. In addition, little information is available on project post-closure status and CO_2 behavior in the subsurface post-injection. Therefore, unlike underground natural gas storage wells, there is not an extensive list of case studies for major leakage from CO_2 EOR wells. The following subsections discuss several studies in which researchers were actively looking for CO_2 leakage from CO_2 EOR projects.

6.1 Weyburn Oil Field, Saskatchewan, Canada

The Weyburn oil field, located in the Williston Basin in southeastern Saskatchewan, Canada, has produced over 356 million barrels of oil since its discovery in 1954. [221] Water-flooding was implemented to increase production in the mid-1960s, followed by the extensive use of horizontal drilling techniques beginning in the 1990s. In October 2000, Cenovus Energy Inc. (Cenovus) (formerly Pan Canadian, EnCana) began injecting large volumes of CO_2 into the Weyburn field to boost oil production. Cenovus is the operator and holds the largest share of the oil field. As of February 2017, the Weyburn project has injected approximately 30 Mt of CO_2, making it the largest CO_2 storage project in the world. [222]

The Kerr family, property owners near the Weyburn field, reportedly found accumulations of algae, unsightly sheens, apparent CO_2 degassing, and deceased animals in and around a pond on their property. [223] [224] [225] Fearing that their groundwater and soil had been contaminated by CO_2 leaking from the EOR project, they hired a geochemical soil consultant, Petro-Find Geochem, Ltd. (Petro-Find Geochem) to investigate by performing soil gas surveys on their property. The first survey conducted in the Summer of 2010. Petro-Find Geochem concluded that “clear” evidence that the provenance of the CO_2 was from the injection operations at the Weyburn field. [226] The findings of this first study were provided to Cenovus and the Saskatchewan Ministry of Energy Resources in January of 2011. Immediate criticism of the study’s findings led to a second Petro-Find study, this time conducted in the winter, beginning in February of 2011. [227]

In first survey, Petro-Find Geochem collected around 30 soil gas samples at a depth of about 3 ft and analyzed the samples for hydrocarbons and CO_2; some of the gas samples were additionally analyzed for the stable carbon isotopes ^{12}C and ^{13}C in CO_2. Samples of the water and mud containing the blue silvery sheen around the edges of the gravel pit were collected and analyzed for the presence of hydrocarbons. The soil gas samples showed high concentrations of CO_2 that averaged approximately 23,000 ppm over most of the property, with concentrations as high as 110,607 ppm. Petro-Find Geochem attributed the source of this soil gas anomaly to the CO_2 injected into the nearby Weyburn-Midale CO_2 EOR field based on the measured range of stable carbon isotope ratios of soil gas being between 21.6 and 22.9 percent, similar to the 20.4 ± 0.4

percent values of the CO_2 injected into the EOR reservoir. [226] However, the Petroleum Technology Research Centre (PTRC), which is responsible for the environmental monitoring of the CO_2 storage project at Weyburn, immediately published a science-based response refuting the allegations, stating that the isotopic signatures of the CO_2, claimed by Petro-Find Geochem to be anthropogenic CO_2 being injected into the reservoir, were in fact, occurring naturally in several locations near the Kerr farm. [228]

Following the allegations, three separately funded, and independently conducted investigations were launched. The first of these was undertaken by European scientists from various institutions who had completed ten years of near-surface monitoring at the nearby Weyburn-Midale CO_2 EOR field. [229] A second study was commissioned by the Weyburn field operators, Cenovus, and undertaken by three third parties external to Cenovus: TRIUM Environmental, Chemistry Matters, and TERA Environmental Consultants. Once completed, the TRIUM Environmental and Chemistry Matters site investigation was then independently reviewed by the PTRC. A third study was coordinated by the International Performance Assessment Centre for Geological Storage of CO_2 (IPAC-CO_2, a not-for-profit R&D organization founded in 2008.

The IPAC-CO_2 study [230] compared the stable carbon isotope and noble gas fingerprints of the Kerr groundwaters to those expected in water, which equilibrated with the atmosphere under local recharge conditions, the produced CO_2 obtained from production wells, and the CO_2 injected into the Weyburn and Midale oil fields. They found that the stable carbon isotope data did not constrain the origin of the dissolved CO_2 in the Kerr groundwaters. Due to low noble gas concentrations in the captured $CO_{2,}$ they were unable to completely rule out the presence of 20–34 percent contribution from injected CO_2 to the groundwaters surrounding the Kerr property. However, they did find that all the Kerr groundwater samples exhibited noble gas fingerprints that would be expected in a shallow groundwater in contact with the atmosphere, and hence there was no evidence for the addition of a deep radiogenic component or dilution from the addition of a gas phase low in atmospheric-derived noble gases. The IPAC-CO_2 study findings corroborate the two previous studies that indicate that elevated CO_2 concentrations found on the Kerr property were almost certainly of biological origin, and not migrated from the deep subsurface.

A review and testing of pipeline infrastructure and well construction and mechanical integrity found no leaks or potential migration pathways for CO_2 and indicated that all infrastructure was sound and operating properly. [230] Sediment, surface water, and groundwater sampling showed no or only trace amounts of hydrocarbons, which may have originated from multiple minor sources such as surface spills or from natural biologic processes. All samples met drinking water quality standards. [230] A sheen or film present in surface ponds, a well, and wetlands was sampled and found to be bacterial in origin— not consisting of hydrocarbons. [230]

All three studies concluded that CO_2 was not leaking from EOR-activities at Weyburn. Equally significant as the conclusion itself are the decisions made by the regulatory agencies to take these allegations seriously and investigate vigorously. Prompt independent investigations of the claims were conducted. The studies were peer reviewed by the PTRC and a panel of subject-matter experts. The peer reviewers found that the designs, methodologies, execution, results, interpretation, and conclusions of the studies were appropriate and reasonable.

Despite the conclusive evidence to the contrary, the Weyburn-Kerr Farm example is still commonly held as evidence of the danger of CO_2 injection and EOR in general. This incident is a lesson for future project developers. It reinforces the importance of site characterization, collection of baseline data, robust monitoring, and having in place a plan to address possible leakage.

6.2 SALT CREEK FIELD, WYOMING

Two different cases of leakage have been reported from the Salt Creek Field in Wyoming. One case of leakage was reported in 2012 when the field was owned and operated by Anadarko Petroleum Corporation, where CO_2 was suspected to have migrated to the surface and into a stream from inadequately plugged wells that were drilled very early in the 20th century. [36] The Wyoming Department of Environmental Quality ordered Anadarko to monitor the acidity of the stream until three consecutive tests indicated normal levels of pH. [231] In a separate incident in 2016, a leak from an abandoned well that comprised both natural gas and CO_2 resulted in the closure of a school in the town of Midwest, Wyoming. To remediate the leak, the new Salt Creek Field operator, Fleur-de-Lis, resealed and plugged the leaking well, and installed air monitoring and a new ventilation system at the school location. [232]

6.3 RANGELY OIL FIELD, WESTERN COLORADO

The Rangely oil field is one of the oldest and largest oil fields in the Rocky Mountain region, producing more than 800 million barrels of oil since the 1940s. [233] [234] It is in Northwestern Colorado within the Uinta and Piceance Basins. [235] Oil was first discovered in the field in the early 1900s; however, it was not until 1933 that oil was found in the Weber Sandstone, the principal reservoir in the field, which accounts for over 98 percent of the total field production. [233] Hydrocarbon gas injection for pressure support began in the 1950s, and waterflooding was utilized for secondary recovery in the late 1950s. [236] ChevronTexaco, the current owner/operator of the Rangely Weber Sand Unit, has been injecting CO_2 into this reservoir since 1986 to increase the volume of recoverable crude oil. In 2011, the Rangely oil field was producing about 11,000 barrels per day which, without CO_2 injection, production would be less than half that amount. [237]

The CO_2 is injected in WAG cycles and approximately 80 percent of the injected CO_2 returns to the surface with produced oil, natural gas, and water. The CO_2, natural gas, and water are all separated from the oil, and all three are re-injected back into the reservoir. The down-hole pressure is noted as 4,500 psi when water is being injected and 5,000 psi when the natural gas and CO_2 are being injected. The typical hydrostatic pressure in the field is approximately 3,000 psi. The CO_2 flooding process, in particular, over pressures the Weber Sandstone and therefore increases the potential for leakage. [217]

Chemical analyses of produced water showed TDS concentrations of 100,000 milligrams per liter in the Weber Formation prior to the start of water flooding in the 1950s. TDS concentration decreased to less than half this value due to the injection of fresher water from the beginning of waterflooding through 1986. Ten years after the commencement of CO_2 flooding, TDS, calcium and bicarbonate concentrations started to increase. Formation water pH decreased to a value of

4.14 from a value of approximately 7.0 in 1986, suggesting that much of the injected CO_2 was in the form of dissolved CO_2 in the formation water (in the form of carbonic acid). [217] [238] X-ray analyses of well scale samples were taken that did not show significant mineralization, further supporting that CO_2 dissolution had occurred. [238] CO_2 dissolved in formation water is susceptible to leakage in the field as there is probability for it to migrate, compared to CO_2 that is sequestered in mineral form or even trapped via capillary forces.

A geochemical study of atmospheric and soil gases was conducted across the Rangely oil field from 2000 through 2002 to assess whether deep sources of CH_4 and CO_2 could be detected at or near the surface. [219] Concentrations of CH_4 were measured in this study because methane remains gaseous within the subsurface, and therefore mobile, while the dissolved CO_2 may precipitate out of solution. Therefore, the CH_4 provides a good proxy for potential leakage. Detections of CO_2 and CH_4 fluxes to the atmosphere and in the soil gas suggest migration of deep sources of both gases from the subsurface. The rate of leakage to the atmosphere was estimated to be 170 tonnes CO_2 per year and 400 tonnes CH_4 per year based on direct flux measurements. [219] However, CO_2 leakage accounts for less than 0.01 percent of the total annual injected CO_2 volume (3.4 Mt/yr), which is within the goals set forth by DOE’s Carbon Storage Program of 99 percent CO_2 storage permanence. [17] [217] Leakage of deep sourced CO_2 and CH_4 did not appear to be related to a fault in the study area, but possibly from a variety of other reasons, including: [236]

- Seal failure due to reservoir over pressure
- Natural fluxes from shallow gas reservoirs
- Gas previously injected to maintain pressure support

6.4 SACROC Groundwater Study, West Texas

The SACROC oil field, located on the eastern edge of the Permian Basin of West Texas, represents North America’s seventh largest oil field with about 3 billion barrels of OOIP. It was the first CO_2 EOR project in North America and is currently one of the world’s largest CO_2 EOR fields. From 1972 through 2010, over 175 Mt of CO_2 has been injected, approximately half has been recovered and recycled. [239] [240]

NETL supported a research effort to perform a field-based groundwater study at the SACROC oil field from 2006 through 2010 to determine if CO_2 injection into the deep subsurface (5,000–6,000 ft depth) would degrade shallow drinking water resources (50–500 ft depth). [240] The SACROC oil field has thousands of active and abandoned wells and, thus, was thought to be a suitable candidate for such a study.

The study investigated groundwater of the Dockum aquifer, a fresh to brackish (< 5,000 milligrams per liter TDS) minor water source that supplies the local population, and is used for irrigation, farming, livestock management, and oil field operations. [241] Groundwater monitoring and water-level measurements were performed, and the results were compared with an online historical database from the Texas Water Development Board. There were generally limited historical groundwater measurements to use as a baseline against which to compare post injection water quality; therefore, sampling occurred both inside and outside the SACROC oil field within an approximately 1,000 square mile area. [240]

Specifically, anomalous pH and TDS values were not observed spatially or temporally. If an increase in CO_2 concentration had occurred within the aquifer, observed pH levels would likely decrease, resulting in possible increased mineral dissolution, and therefore, a subsequent overall increase in TDS. [190] Overall, the results found no significant differences between groundwater pH and TDS inside versus outside of SACROC. All samples were within normal regional variations with no obvious impacts to fresh groundwater due to interaction with large volumes of CO_2. The variation in chemistry throughout the region is most likely due to several factors, which include geologic heterogeneity, the lengthy history of oil and gas activity in the region, and groundwater wells completed in different stratigraphic intervals and mislabeled as being completed in the Dockum aquifer. [240] However, higher concentrations of chloride were detected in the water samples from within SACROC compared to outside the oilfield, suggesting mixing of the Dockum aquifer groundwater with fluid that contains a higher concentration of TDS. [240] [241] While mixing models predicted that the fresh water samples within SACROC would contain less than one percent produced fluid, it does not necessarily indicate proof of brine leakage. Any observed fluid mixing is believed to be most likely related to the lack of environmental awareness best practices prior to the mid-1970s. For instance, fluid mixing is believed in part due to the historic disposal of brine in unlined surface pits, as opposed to leakage from a compromised production or injection well, as no increase in CO_2 and subsequent decrease in pH was observed. [240] [242] Current well completion practices (like protective surface casing and extensive cathodic protection networks) make migration of fluids from the deep subsurface to the freshwater zone less likely. [240]

6.5 West Pearl Queen Field Test, Southeast New Mexico

The West Pearl Queen depleted gas field, though not an active EOR field, was chosen to be the first test field in the United States on the feasibility of storing CO_2 in depleted oil and gas reservoirs, and thus included in this report. The West Pearl Queen field is in southeastern New Mexico at the edge of the Permian Basin and has produced approximately 250 million barrels of oil since 1984. [243] [244] While oil production has steadily declined in the field, no secondary or tertiary methods have previously been applied to the field. Therefore, the field had not undergone CO_2 injection, making it an ideal test site for CO_2 storage research. [244]

Approximately 2,000 tonnes of CO_2 were injected at the site over a period of 50 days from December 2002 to February 2003. [243] After the injection was completed, the CO_2 could interact with the reservoir over a period of six months, after which the CO_2 was pumped out and vented to the atmosphere. To assess potential CO_2 migration, perfluorocarbon tracer gases (PFTs) were added as three 12-hour slugs at about one-week intervals during injection. Soil gas was monitored using capillary adsorbent tubes set at depths of 2–5 ft in the subsurface and were measured over a period ranging from days to months. PFTs were detected in soil gas at the monitoring sites 50 meters from the injection well within a few days of injection, and eventually extended out to 100 meters radially from the well. [245]

Atmospheric sampling was performed to evaluate any possibility of PFTs emanating from the ground to the atmosphere to monitor leakage. Atmospheric samples were collected at 50 meters and 300 meters downwind and 300 meters upwind from the injection well. PFTs were not detected above background levels during injection or during the period of shut-in. However, PFT was detected in the atmosphere following a period of venting at the injection well, including at the sample site located 300 meters upwind of injection well. [245] Intentional venting, however, is a rare event during EOR operations. [36] While no PFT was detected in the air with the exception during the venting period, soil gas sampling detected PFTs in the soil gas near the injection well, suggesting leakage associated with the wellbore. Specifically, elevated PFT concentrations around the wellbore appeared in a thin layer of sand that overlies a caliche layer that lies at approximately one-meter depth. Over time the caliche has undergone significant weathering, which most likely allowed for the formation of high permeability pathways. The leakage rate was estimated from soil measurements at approximately 0.0085 percent of the total CO_2 stored per year. Leakage was uniform over months of observation and continued for years. This suggests that the source of leakage is most likely not related to the wellbore over the long-term, but rather the reservoir is most likely the source of fugitive CO_2. Over pressurization was observed during injection that may have fractured the cement between the well casing and seal rock, creating a pathway for migration of CO_2 up the wellbore, and through the soil fractures caused by over pressure. [245]

6.6 Follow-up and Lessons Learned from Case Studies

Communication with the surrounding community is vital to allaying fears about leaks and their effects. Unfavorable public perception can be greatly reduced by clear, understandable, transparent dialogue with the residents and government officials within the region operations may impact the most. This was very well illustrated by the way the Weyburn field case was handled. Cenovus and IPAC-CO_2 took the allegations of leaks seriously, and both performed peer-reviewed studies to investigate the complaint. When the studies were completed and made public, the Natural Resources Defense Council commended the way the complaints were thoroughly and scientifically investigated. [246] The Weyburn incident also illustrates the importance of site characterization, collection of baseline data, robust monitoring, and having a plan in place to address possible leakage. In the end, because of the amount and quality of the data available, the studies concluded that CO_2 was not leaking.

In general, the public perception associated with CO_2 EOR is considered favorable. Hill et al. (2013) [36] have indicated that the public is familiar and comfortable with the process of oil production; therefore, there is often little resistance or opposition towards its implementation. One influencing factor for this trend could be related to the extent to which projects will be visible or entail significant changes to the physical appearance of a site. For example, in the case of EOR operations where minimal new infrastructure may be necessary compared to the existing infrastructure already in place from primary and secondary production. In other cases, like for geologic CO_2 storage project, there could be a need to install a significant volume of new infrastructure at the site. Public outreach programs can anticipate these future changes and help to build stakeholder awareness and expectations. [247]

7 CONCLUSIONS

It is important that regulators, the scientific community, and the public have confidence that CO_2 geologic storage can be safe and secure. To this regard, evidence in the form of industrial analogs like CO_2 EOR operations can be used to show that geological storage of CO_2 can indeed be carried out effectively and safely when best practices are implemented. Through this report, it is possible to see how CO_2 EOR industry provides case studies that enable identification of key features and considerations that are likely to be effective for CO_2 storage, as well as learning points from the small number leakage-related incidences that have occurred. The potential leakage risks associated with Class II EOR wells include injected CO_2 or native fluids migrating away from the produced reservoir and into USDWs or the atmosphere. However, despite over 40 years of operating CO_2 EOR projects, significant CO_2 leakage events have rarely been reported. [36] In cases where leakage was identified, it was caused by inadequately plugged wells of older vintages (e.g., Salt Creek Field in Wyoming), or as a result of an operational oversight, such as over-pressuring the reservoir and creating a leakage pathway by activating a fault (e.g., Rangely Field in Colorado). With careful adherence to the regulations, and implementation of best practices, leaks related to CO_2 EOR can be avoided. Additionally, unfavorable public perception to CO_2 EOR operations has been found to be greatly reduced by clear, understandable, transparent dialog with the residents and government officials within the region where operations may have an impact. Pre-injection baseline monitoring of surrounding ecosystems could also be a good best practice for future CO_2 storage sites. Acquiring this type of data enables evaluation for parameter changes which may indicate (or refute) leakage. The Weyburn project provided a compelling case for acquiring baseline data prior to initiating CO_2 injection for both CO_2 EOR and saline reservoir storage. Studying analogs to CO_2 storage helps to improve overall understanding of both the technical concept and its application—in this case, large-scale geological CO_2 storage in saline-bearing reservoirs involving millions of tonnes of CO_2. [19]

There are significant similarities that exist between CO_2 EOR operations using UIC Class II wells and CO_2 geologic storage (and essentially full-scale CCS) using UIC Class VI wells. Significant similarities noted in this report between the two practices include the injection of the same fluid (predominantly supercritical CO_2), the need for an adequately thick caprock to ensure long-term containment (ideally with a secondary caprock above the primary seal), and adequate porosity and permeability to enable effective storage capacity (in the case of EOR, pore space that enables ample HCPVs of residual oil) and injectivity, respectively. For both well types, injection wells must be properly designed, installed, monitored, and maintained. Any abandoned wells in the project AoR must be located and, if needed, properly plugged to prevent leakage pathways. [4] Careful control of injection pressure and final reservoir pressure based on geomechanical properties is necessary under both practices to avoid damage to the caprock. Generally, these types of parameters can be properly identified through site selection and geologic characterization of candidate storage sites. [19] Additionally, the operations for both practices are concerned with monitoring for leakage, both underground and at surface facilities. The regulations associated with the different well classes dictate more robust monitoring for CO_2 storage operations under UIC Class VI. From a regulatory perspective, both

Class II and Class VI wells are governed by EPA UIC regulations. Overall, UIC Class VI wells are bound to more rigorous requirements regarding well construction and site monitoring compared to Class II wells. The differences in requirements are to account for the unique considerations associated with CO_2 storage, including the long operational timeframes and greater volumes of CO_2 stored in the subsurface compared to UIC Class II wells used for CO_2 EOR purposes. [84] Currently, North Dakota is the only state that holds primacy over Class VI wells in addition to the other UIC well classes. [248]

While similarities exist between CO_2 EOR and saline-based geologic storage of CO_2, there are substantial differences between the two practices. For example, the primary objective of the two practices differs despite the common theme of injecting CO_2 into the subsurface. For CO_2 storage, the objective is to maximize storage of CO_2 from anthropogenic sources, while in EOR, the objective is to maximize oil production while minimizing CO_2 usage. [2] Additionally, the commercial application and experience with each practice is different. CO_2 EOR is a thoroughly commercialized industry that has undergone relatively safe and successful operations for over 40 years. On the other hand, CO_2 storage is a relatively new and emerging technology. Successful demonstration of injection and storage of CO_2 has occurred in early field testing projects, [6] [8] [17] but many believe continued research is needed to significantly improve the effectiveness of CO_2 storage-related technologies, reduce the cost of implementation, and generate data, best practices, and lessons learned in order to facilitate widespread commercial deployment into the future. [8] [9] CO_2 EOR operators have a long history of successful operations and have therefore developed an understanding of reservoir properties and performance for depleted oil and gas fields. For instance, CO_2 EOR operators deploy flooding in patterns (i.e., 5-spot, 9-spot, line drive, etc.) across an oil field which consist of multiple injection and production wells. Additionally, CO_2 EOR operations require extensive surface infrastructure and facilities for processes like fluid production and separation, and CO_2 recycle. This type of injection design is drastically different from the approaches implemented in previous CO_2 storage field projects, which have typically limited injection through one well (FutureGen 2.0 was an exception where four horizontal injection wells were planned to be used), no fluid production occurs (with the exception of geochemical sampling), but extensive monitoring networks may have been installed and active before, during, and after injection operations.

CCS-related R&D can benefit by drawing lessons from the history of other energy technologies and industries that were once considered risky and expensive early in their commercial development. Building CCS into a key component for managing and utilizing CO_2 from anthropogenic sources will require affordable and effective technologies (associated with clear policies that support widespread deployment), and development of lessons learned and best practices from examples of analog industries that have faced similar technical hurdles but have eventually attained commercial success. [9] Additionally, Rai et al. identified multiple non-technical factors that have facilitated commercial adoption of industries analogous to CO_2 storage that are worth noting. [9] Due to their importance, these are further explained in Appendix A: Overview of Rai et al., 2010. Through this report (and others like it pertaining to wastewater disposal using UIC Class I disposal wells [249] and underground natural gas storage [250]) critical findings from the experience of CO_2 EOR can be leveraged in the future, as well as be used to demonstrate that a level of understanding for how failures that resulted in leakage events have occurred (and were remediated) in past operations has been achieved, so that CO_2 storage best practices can be developed and implemented moving forward.

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APPENDIX A: OVERVIEW OF RAI ET AL., 2010

Rai et al. [9] identified that several successful technologies, including energy technologies, have faced challenges like those faced by carbon capture and storage (CCS). They analyzed the development of the United States (U.S.) nuclear-power industry, the U.S. sulfur dioxide-scrubber industry, and the global liquefied natural gas industry to draw lessons for the CCS industry from these energy analogs that, similar to CCS today, were risky and expensive early in their commercial development. This appendix captures key messages from the Rai et al. study.[p]

Rai et al. began their analyses by identifying the main obstacles to scaling and widespread deployment of CCS. The analyses highlight how each analogous industry overcame challenges similar to CCS and how each evolved with respect to technology innovation and demonstration, cost, technology diffusion, and business risk reduction. These challenges to CCS are:

- **Extremely high capital intensity of fully developed CCS projects**: Capital costs are projected to increase nearly 50 percent for coal power plants with CCS compared with the non-CCS option; however, early commercial projects may benefit from subsidies/grants. [251] In addition, high capital expenditures usually translate to an extended time horizon over which the project must generate positive cash flows to become commercially viable. Ensuring this type of income stream over extended durations can be difficult when employing new technologies with unproven track records. Therefore, the requirement of large capital investments in CCS projects presents a major hurdle.
- **Uncertain revenue stream owing to the lack of reliable and sufficiently high pricing for CO_2 abatement**: The lack of an inherent value of CO_2 (as opposed to nuclear power or liquefied natural gas) requires regulatory action (or financial incentives) to generate revenue streams for CCS projects. Currently, CCS can increase the cost of electricity upwards of 50 to 75 percent per megawatt hour generated. [54] Typically, the demand for high-cost electricity is prompted through policy incentives (like mandatory renewables portfolio standards as in many U.S. states) and feed-in-tariffs for electricity from renewable energy sources (like those in Germany). But no demand-pull schemes exist for CCS. Putting a price on carbon may still not generate enough incentive to attract the necessary scale of investments in CCS for widespread deployment. Therefore, most CCS projects in operation or with a high probability of successful development depend on other circumstances that do not apply at broad scale. These include special government policies (e.g., Norway's carbon tax, which incentivizes CO_2 storage) and the unique opportunity for enhanced oil recovery from mature fields when oil prices are high. CCS projects will remain risky undertakings until reliable systems become available that more broadly ensure cost recovery.
- **Uncertainties in regulation and technical performance**: There is extensive experience world-wide in capturing CO_2 in the chemicals and natural-gas processing industries. However, technology and operational experience is still lacking for CCS from power

[p] The study can be found at http://ilar.ucsd.edu/_files/publications/studies/2010_carbon-capture.pdf.

plants. The shortage of experience makes cost and performance predictions difficult, which also contributes to additional uncertainty pertaining to the long-term viability of investments in commercial-scale CCS. Uncertainty can also lead to over-regulation of CCS operations (in terms of capture as well as permitting requirements), requiring excessive monitoring and risk reduction and management options that drive up costs to implement.

- **Complex value chain that multiplies risks and uncertainties across the whole series of activities that together compose a viable CCS project:** Scale-up of CCS would require collective action of commercial entities that would make up each portion of the CCS value chain; each of which has very different risk profiles. For example, the U.S. power generation industry is dominated by risk-averse regulated utilities, whereas much of the knowledge about geologic CO_2 storage is typically held by oil companies that thrive on risk. The diversity in the risk profiles across the same value chain may be prohibitive towards investment, as the partners across the value chain may find it difficult to manage co-dependent commercial risk. CCS is not yet at the point in which the ability of the CCS industry to organize at scale in different regions and regulatory contexts has been fully tested, but relevant players do understand the complexity of the CCS value chain and the challenges with sorting out details and integrating at a commercial-scale.

Through analyzing the development of the analogous industries to CCS, Rai et al. arrived at three principal observations from which the analogous industries could achieve success:

- Government has had a decisive role in the development of analog industries. For instance, analog industries typically benefitted from government support for early research and development, as well as for deployment in niche markets. There are similar steps being taken today for CCS development both in the United States and internationally.
- Diffusion and penetration of these technologies beyond early demonstration and niche projects is facilitated by the credibility of incentives for industry to invest in commercial-scale projects. In the United States, the modified 45Q tax credit and updated corporate tax structures could provoke a business case for CCS. [252] [253]
- The "learning curve" theory, where experience with technologies inevitably reduces costs, does not necessarily hold. Real learning is driven by more than just technical potential; it can also be influenced by the institutional environment present and any incentives towards cutting costs or boosting performance. The U.S. nuclear power industry and global liquefied natural gas industry are noted examples where costs had increased with increasing capacity, contradicting the "learning curve" theory. Stakeholders in the CCS community must remain mindful that cost reduction is not automatic as more projects progress—it can be derailed especially by non-competitive markets, unanticipated shifts in regulation, and unexpected technological challenges. Risky and capital-intensive technologies may be particularly vulnerable to wider-spread commercialization without accompanying reductions in cost.

APPENDIX B: EXPANDED REVIEW OF CO_2 SOURCES IN THE UNITED STATES

Expanded Discussion of Naturally-Occurring Geologic CO_2

Naturally-occurring, geologic CO_2 systems are analogous to classic petroleum systems consisting of source rock, migration path, trap, and seal. The migration pathways, traps, and seals are largely identical to those found in methane deposits, and quite often the molecules are found coincidentally. The key difference in a CO_2 system is the source. Whereas hydrocarbons are almost exclusively created from the thermal maturation of rocks with a high content of organic matter, CO_2 can be created from multiple origins, including intrusive magmas, subduction zone magmatism, thermal alteration of carbonates, and other chemical processes including the biodegradation of hydrocarbons. [254]

By far, the most significant origin in terms of producing large trappable CO_2 deposits, particularly in North America, are ultramafic, mafic-alkaline, and felsic-alkaline intrusive magmas. CO_2 and water (H_2O) are two of the dominant gases in magmas, but all magmas do not provide the same proportions or conditions to allow formation of large CO_2 deposits. Calc-alkalic magmas, related to island arcs and subduction zones, have high concentrations of H_2O; trapping of CO_2 is a problem in arc settings because of the explosive eruption styles. Very different from subduction zone and island arc settings are intraplate settings where ultramafic or mafic-alkaline and felsic-alkaline magmas form. These magmas have high CO_2 content and are localized in relatively small sub-vertical plutons, plugs, diatremes, or breccias pipes spatially associated with crustal deformation that is optimal for the entrapment of focused CO_2 deposits. Magmas of this chemistry (ultramafic, mafic-alkaline, felsic-alkaline) carry the most CO_2 and are the likely sources of the giant CO_2 domes such as McElmo, Bravo, and Big Piney-LaBarge (BPLB). [254]

Most CO_2 deposits discovered to date have been the by-product of exploration efforts for hydrocarbons. An examination of public-domain literature in a survey by Enegis, LLC conducted for NETL [254] in 2012 identified 21 fields or structures (and documented critical geologic parameters like water saturation, initial gas formation volume factor, permeability, and porosity) containing geologic CO_2 resources. These sources are identified in Exhibit B-1 and summarized in detail, and their locations are shown in Exhibit B-2.

While several naturally-occurring CO_2 deposits have been discovered, they inherently vary in the overall volume of CO_2 accumulated, as well as in their geologic properties. Therefore, they are not expected to produce CO_2 equivalently. A methodology for evaluating the recoverability of CO_2 resources has been developed by Enegis, LLC [254] that is based on that developed for the assessment of unconventional natural gas resources. The method for this analysis is deterministic based on average geologic properties of reservoirs containing CO_2 accumulation, (analogous to P_{50} estimates for CO_2 storage capacity in saline-bearing formations). The methodology comprises three steps that make up a resources hierarchy:

1. **Gas-initially-in-place (GIIP)—**all the gas that exists in a given structure, reservoir, or formation prior to an extraction

2. **Technically recoverable resources (TRR)—**a subset of GIIP comprising that portion that can be recovered by technical means without explicit consideration of economics
3. **Economically recoverable resources (ERR)—**a subset of TRR that meets economic criteria for potential production and is amenable for development into reserves[q]

A spreadsheet analytical tool (built in Visual Basic for Applications Microsoft Excel platform), named the CO_2 Resources Evaluation Analytical Model (CREAM), was used as part of the 2012 NETL study [254] to develop CO_2 resource estimations based on the project dataset culled from the survey of public literature. CREAM is driven by input parameters for the GIIP containing equations and algorithms for estimating TRR and ERR. In this study, NETL assessed 21 discovered fields for GIIP, TRR, and ERR. Of the 21 fields examined, nine were currently producing CO_2. Of these producing operations, five have undergone significant expansions or are planning significant expansions in the near future and four were previously in operation and are currently inactive. The remaining eight fields have been discovered and not developed.

Results show that discovered GIIP resources are about 309 Tcf, of which about 167 Tcf are TRR (Exhibit B-1). Of this accessible resource, an estimated 19 Tcf have been produced and upwards of 97 Tcf may be able to be economically developed.

BPLB in the Greater Green River basin of Wyoming is the largest single discovered CO_2 resource in the United States with estimated GIIP of 173 Tcf, which is over 50 percent of the assessed resource base. The basinal portion of BPLB has an estimated remaining ERR of over 43 Tcf. BPLB has been developed for its methane production but is experiencing significant increases in the use of its CO_2 EOR. Kevin Dome, which is in Montana and straddles the Canadian border, is undeveloped and contains about 14 Tcf of ERR (U.S. portion only). Several other fields are available with greater than Tcf of remaining ERR.

Most if not all the subsurface accumulations of CO_2 in the United States were discovered unintentionally during exploration operations aimed at finding hydrocarbon resources. The science of exploration for CO_2 is immature compared to that of exploration for hydrocarbons and CO_2 has characteristics that make the search for it different. In general, CO_2 in the United States tends to originate from magmatic chimneys rather than from buried carbonate rocks. As such, accumulations tend to be structurally controlled and more aerially restricted than hydrocarbon accumulations.

An examination of public-domain literature based on the sourcing and tectonics for subsurface CO_2 systems conducted by Enegis, LLC [255] identified several leads in five different geographic regions of the U.S.; in which 63 Tcf of risked CO_2 initially in place and 42 Tcf of risked technically recoverable CO_2 resource (Exhibit B-3).

[q] Note that this analysis does not assess reserves in a Securities and Exchange Commission context.

Exhibit B-1. Discovered geologic CO_2 deposits and resource estimates in the U.S. Lower 48 [254]

CO_2 EOR System	Structure or Field	State	2013 Production (MMscf/d)	Rock Type*	Depth	Area	Pay	Por	Formation Volume Factor	Rec	Access	Gas Components (%)					Resource Estimates (Tcf)				
					1,000 ft	1,000 acres	ft	%	rcf/(1,000 scf)	%		CO_2	CH_4	N_2	He	H_2S	Gas Initially in Place	Technically Recoverable Resource	Gross Economically Recoverable Resource	Cumulative Production	Net Economically Recoverable Resource
Permian Basin	McElmo Dome	CO, UT	1,135	LS	8	202	95	12	2.6	70	65	98	-	2	0.01	-	30	14	12	7.2	4.4
	St. Johns	NM, AZ	-	SS	1.5	220	75	15	9	70	80	93	-	4	0.60	-	8.9	5.0	4.3	0.09	4.2
	Bravo Dome	NM	405	SS	2.6	700	125	20	16	65	90	97	-	-	0.02	-	23	14	5.4	2.9	2.5
	Doe Canyon	CO	105	LS	9	82	60	10	3.2	70	75	95	-	-	-	-	5.1	2.7	1.1	0.09	1.0
	Val Verde	TX	165	Dol	14	70	650	4	3.5	70	95	42	58	-	0.01	-	7.3	4.9	1.6	1.5	0.1
	Oakdale	CO	-	SS	6	3	250	19	3.5	65	80	72	28	-	0.03	-	1.2	0.6	0.5	0.0	0.5
	Sheep Mntn	CO	45	SS	5	12	145	20	3.9	65	80	97	1	-	0.03	-	3.1	1.6	1.4	1.3	0.1
	Lisbon	UT	-	LS	10	3	75	12	3.8	70	85	90	-	-	-	-	0.2	0.1	-	-	-
Rocky Mountain	BPLB Basinal	WY	108	SS, Dol	16	138	275	9	2.8	70	85	85	9	3	0.50	2.4	113	67	45	1.5	43.2
	BPLB Foreland	WY	107	SS, Dol	16	125	275	9	3.2	70	80	74	15	6	0.50	4.2	30	17	7.2	1.5	5.7
	BPLB Highland	WY	-	SS, Dol	18	388	275	9	3	70	30	81	11	4	0.50	3.0	30	6.4	3.2	-	3.2
	Madden	WY	35	Dol	24	80	175	15	3.8	70	95	20	67	-	-	12	3.8	2.5	-	0.08	-
Gulf Coast	Jackson Dome	MS	1,025	LS	16	90	185	13	2.8	70	95	90	5	-	-	5.0	24	16	11	1.8	8.9
Not Connected to a System	Escalante	UT	-	SS, LS	2.3	37	172	7	9.1	55	45	95	-	4	0.01	-	10	2.5	1.7	-	1.7
	Kevin Dome	MT	-	LS	3.6	261	67	9	5.3	75	95	88	-	12	-	-	14	10	1.1	-	1.1
	McCallum	CO	1	SS	5.5	15	100	20	3.5	70	90	92	-	-	0.11	-	2.8	1.8	1.5	0.9	0.6
	Gordon Creek	UT	-	LS	13	8	135	9	2.4	65	90	99	-	-	-	-	1.7	1.0	0.6	-	0.6
	Indian Creek	WV	0.1	SS	6.7	18	10	10	3.7	70	95	66	30	4	0.15	-	0.1	0.1	-	0.02	-
	Woodside	UT	-	SS	3.5	13	45	9	5.2	60	90	32	-	62	-	-	0.1	0.1	-	-	-
																	309	**167**	**97**	**19**	**78**

*LS = Limestone; SS = Sandstone; Dol = Dolomite

Exhibit B-2. Discovered CO_2 deposits in the U.S. Lower 48 [254]

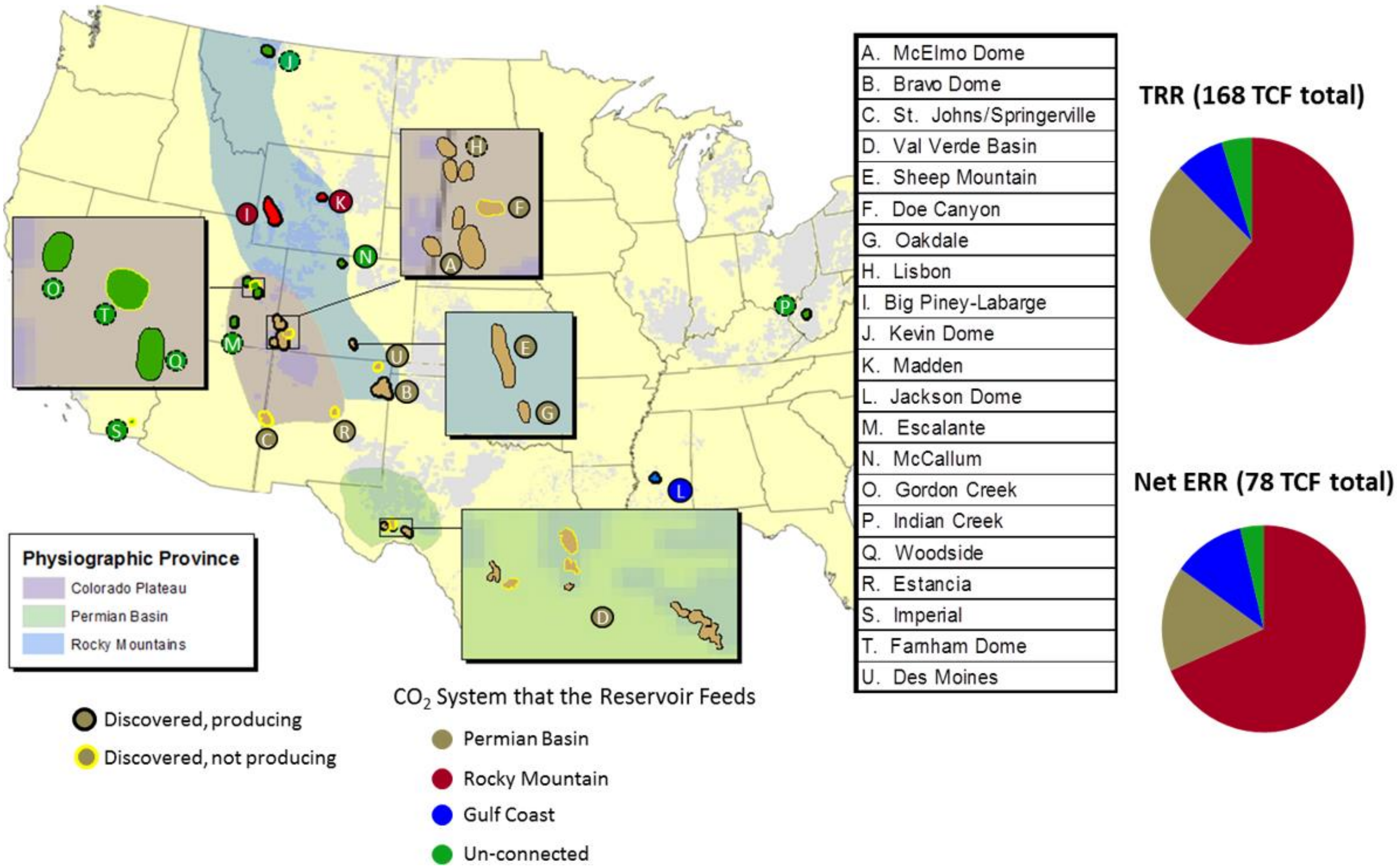
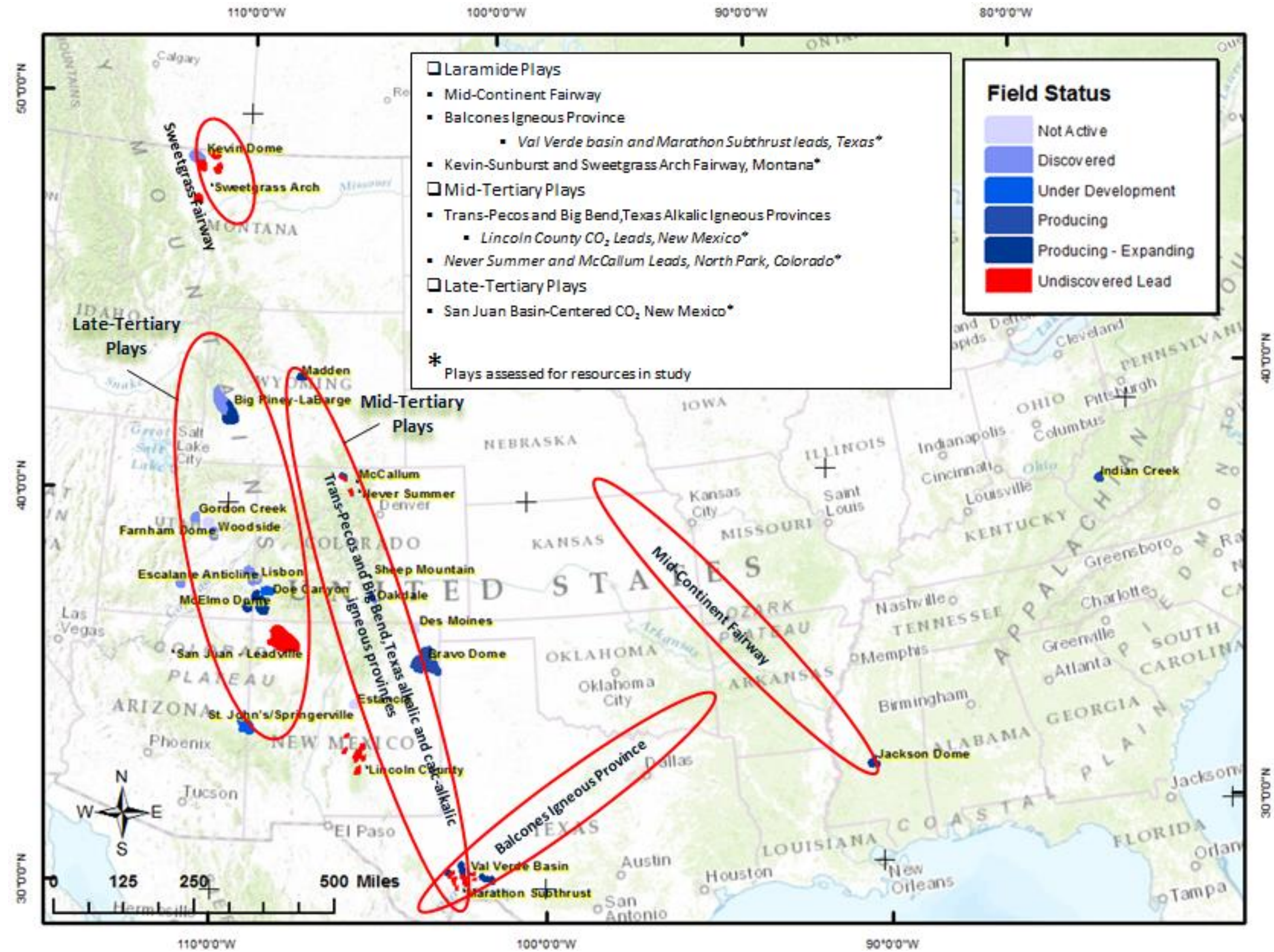


Exhibit B-3. Identified undiscovered CO_2 leads [255]



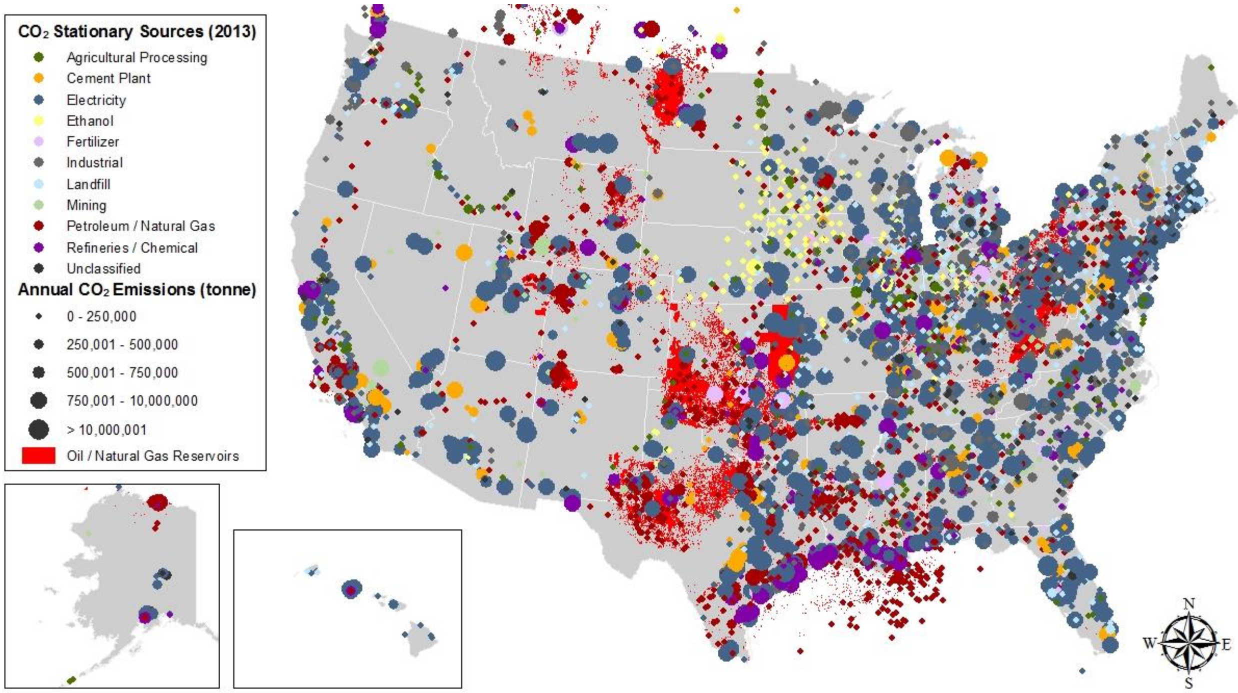
The NETL report *Volume II: Undiscovered Subsurface Sources of CO_2 in the Contiguous United States* contains description of the data compiled and the tectonic narratives for each of the leads. Key findings include [255]

- The San Juan is the largest lead at 22 Tcf CO_2 TRR (risked). Unlike other leads, it is an unconventional resource. The strata of interest in the San Juan are 13,500 feet below the surface, four to six thousand feet deeper than current hydrocarbon production wells. Data from a small number of penetrations at this depth reveals produced gas containing 90 percent CO_2.
- Mapping of composition data from several natural gas production wells in the Val Verde (sub-basin of the Permian Basin in Texas) region shows CO_2 concentrations trending higher for wells that are further south toward the Marathon Thrust zone. These data point to a magmatic chimney to the south. Two clusters of leads are identified, above and below the thrust plane (12,000 and 15,000 feet).
- The Sweetgrass Arch leads are in the same CO_2 system as Kevin Dome. The leads are areas where there is evidence of traps along the apparent migration pathway.
- Lincoln County, New Mexico, is the location of some of the most speculative of the leads. Well data with the elevated CO_2 concentrations and the presence of magma provide evidence of an emplacement of CO_2.
- The North Park, Colorado, area contains two leads, indicated by the producing McCallum field, which is a hanging-wall trap. One lead is an associated foot-wall trap. A second lead, located to the south, is co-tectonically associated with the McCallum backthrust.

Expanded Discussion on Anthropogenic Sources of CO_2

The National Carbon Sequestration Database and Geographic Information System (i.e., NATCARB) [256] and the Carbon Storage Atlas – 5th Edition [14], both developed by NETL, have documented the stationary sources of CO_2 emissions across the United States and parts of Canada. For instance, the 5th edition of the Carbon Storage Atlas documents 6,358 stationary CO_2 sources with total annual emissions of approximately 3,017 Mt (roughly 58,077 billion cubic feet of CO_2). [14] These data are shown in Exhibit B-4 and grouped into one of 11 source types. Additionally, Exhibit B-4 features the location of oil and gas reservoirs in relation to anthropogenic CO_2 sources.

Exhibit B-4. Location of CO_2 stationary sources relative to oil and natural gas reservoirs in the United States [256]



For perspective, in 2013, McElmo Dome and Jackson Dome each produced over 1 billion cubic feet per day (approximately 0.63 percent of the daily total CO_2 emissions reported by the 5th edition of the Carbon Storage Atlas). Typically, geologic sources are significantly more pure than post-combustion anthropogenic sources, requiring significantly less clean up and scrubbing. Non-post-combustion sources of CO_2, such as cement, ethanol production, and fertilizer plants, produce nearly-pure streams of CO_2, but simply do not produce enough CO_2 quantities individually to supply a large EOR operation. The opportunity for anthropogenic sources to supply CO_2 for EOR exists in areas that are isolated from geologic supply of natural CO_2 sources, particularly in areas where multiple anthropogenic sources can supply CO_2 to a common CO_2 pipeline. An example of this can be found in the Oklahoma EOR market (isolated from CO_2 supply from the Permian Basin system) where CO_2 from the Enid fertilizer plant and other isolated sources are feeding EOR fields is Oklahoma and the Texas panhandle. Expansion of this market with pipeline buildouts recently connected the Oklahoma system with the larger Permian Basin pipeline network.

A crucial point to take away from this appendix is that CO_2 exists as an abundant natural resource. However, several studies have indicated that a lack of a sufficient supply of CO_2 to could affect sustained CO_2 EOR growth, [46] and that considerable volumes of CO_2 will be required to meet potential next generation EOR. [36] [45] Anthropogenic sources provide a means to enable the expansion of future EOR markets. The most emergent opportunity for anthropogenic CO_2 use for EOR could be in areas that are isolated from existing, naturally-occurring CO_2-fed markets.

APPENDIX C: OVERVIEW OF THE FIVE STATES WITH THE MOST CLASS II WELLS

This appendix is for informational purposes only. It is not to be considered a complete listing of requirements or regulations but mentions examples of regulatory considerations specific to the states reviewed that have the greatest number of Class II wells. The well volume pertaining to each state discussed below can be referenced in Exhibit 3-4. [95]

California

California has the most Class II wells; roughly one third the Class II wells in the United States. California has over 54,000 Class II recovery wells, which is roughly 37 percent of all the recovery wells in the United States. [95] California currently has primacy for only Class II injection wells, which are regulated by the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR). Regulation for Class II was adopted from the federal requirements governing underground injection control (UIC) wells, Section 146.4 of Title 40 of the Code of Federal Regulations, are outlined in the California Code of Regulation, Title 14, Division 2, Chapter 4, and include the following:

- A geologic and injection plan must be submitted to DOGGR to receive a permit, which includes a representative electric log, a structural and isopach map, and a cross-section of the area at a minimum.
- For an AoR using a fixed radius of one-quarter mile, the chemistry of the injected and formation fluids, hydrogeology, population, groundwater use, and dependence and historical injection practices in the area must be taken into consideration.
- Plugged and abandoned wells within the AoR are required to have oil and gas bearing strata to be isolated.
- Injection wells must, in addition to cement above the oil and gas zones, have cement across the base of the freshwater interface that extends to at least 100 feet above the base of freshwater interface.

In 2011, California was noted as being out of compliance with SDWA requirements for Class II injection wells. [257] The noncompliance resulted from confusion between differing versions of the Memorandum of Agreement between California and EPA, which mistakenly listed 11 aquifers as exempt. [258] In 2011, EPA audited the DOGGR's Class II UIC primacy program and identified implementation deficiencies. In 2012, EPA conducted a review of aquifer exemptions that raised questions about the alignment of injection wells with EPA approved exemption. [257] DOGGR had been permitting injection into sub-3,000 ppm TDS aquifers, leading to more than 5,500 EOR wells being improperly permitted. [259]

In 2014, EPA increased its oversight efforts of California's UIC program, highlighting their concerns and requesting a specific plan and timeline for DOGGR to address the deficiencies in its program. [260] The State Water Resources Control Board and the DOGGR's March 2015 Corrective Action Plan included a schedule of required activities and deliverables, including target milestones, to track progress toward a compliance deadline of February 2017 for which injection into aquifers containing less than 10,000 parts per million TDS must cease. [261] EPA Region 9 has been working with the DOGGR and the State Water Resources Control Board to ensure California's UIC program is in full compliance with the SDWA. As of August 22, 2017, DOGGR's corrective review of underground injection well information is ongoing, with attention on wells that may have the highest risk to California aquifers. [262]

California has taken on development of statewide GHG emissions limits through the development of rules and regulations per California Assembly Bill 32. The state has recognized CCS as a key technology option to effectively manage CO_2 emissions from the state's power plants and industrial sources. As a result, the California Public Utilities Commission, California Energy Commission, and the California Air Resources Board created the California Carbon Capture and Storage Review Panel in February 2010. The review panel comprised experts from industry, trade groups, academia, and environmental organizations focused on identifying, discussing, and framing policies for addressing the role of CCS technology in meeting the state's energy needs, as well as support the development of a legal/regulatory framework for permitting proposed CCS projects. [263] In December 2010, the review panel issued recommendations [263] to guide the development of legislation and regulations regarding CCS in California. In April 2017, the California Air Resources Board issued a concept paper [264] for a regulatory program on CCS. This concept paper described the board's vision for what a draft quantification methodology and permanence protocol should contain, and what some of the requirements might be. After the release of this concept paper, the board plans to hold a workshop and collect feedback to continue development of the draft quantification methodologies and permanence protocol.

Texas

Texas has more nearly 30 percent of all U.S. Class II wells and ranks second. In 2009, the Texas Legislature passed Senate Bill SB 1387, which amended Water Code 27 to authorize the Railroad Commission of Texas to regulate the injection of fluids into reservoirs that are producing or may produce oil, or saline formations directly above or below such reservoirs. However, the Texas Administrative Code (TAC) specifically excludes EOR-related wells from permitting requirements that are imposed on other injection wells for geologic storage of CO_2. [265] TAC also states they have jurisdiction over the conversion of an injection well for any purpose to one that uses anthropogenic CO_2 for EOR operations or for geologic storage. Additionally, TAC specifies that conversion of an anthropogenic CO_2 injection well from use for EOR to one for geologic storage is not considered to be a change in the purpose of the well, and therefore, avoids the wells having to be re-permitted as a CO_2 injection well. [266]

The operator of an EOR project may propose to permit the EOR project as a CO_2 geologic storage facility simultaneously (Class VI UIC well). This does not preclude an EOR project operator from opting into a regulatory program that provides carbon credit for anthropogenic CO_2 stored through the EOR project. TAC Title 16, Part 1, Chapter 3, Rule §3.46 outlines the regulations for Fluid Injection into Productive Reservoirs, issuing permits only when injection will not endanger oil, gas, or geothermal resources, or cause the pollution of freshwater aquifers. State specific regulations for Class VI wells in Texas under Rule §3.46 are outlined below:

- Operators of wells within a half mile must be notified regardless of the status of the wells. The only wells that may be excluded are wells that have been permanently plugged and abandoned.
- A complete electric log of the proposed injection well is required. If an electric log is not available for the well, a log from a nearby well may be used.
- Wells converted from production to injection are reviewed on case-by-case basis, and if permitted require more frequent testing and monitoring. For example, testing frequencies may differ, like annual MITs and weekly tubing-casing annulus monitoring vs. 5-year MIT and monthly tubing-casing annulus monitoring if well is constructed to current standards.
- Six hundred feet of cement is required above the casing shoe, or shallowest productive interval. If the top of cement is based on volume calculations, at least 400 feet of cement is required above the productive zone.
- Fracture step rate test is required to measure the fracture pressure of a given formation to demonstrate that fracturing of the formations will not occur at the proposed injection pressure.
- Operators must set and cement surface casing below the base of usable quality groundwater as determined by the Texas Groundwater Advisory Unit.

Kansas

Kansas ranks third among U.S. states in the number of Class II wells, with about 9 percent of U.S. total. Kansas has UIC Class II primacy, which is administered by the Kansas Corporation Commission (KCC). Kansas has generally adopted the federal requirements governing UIC wells in 40 CFR 144 and 146; most of the exceptions to the federal regulations deal with Class III salt solution mining wells. The UIC program is regulated under Kansas Administrative Regulations 82-3-400 to 82-3-412. The KCC indicates that these regulations are tailored to protect USDWs from harm from improper injection. [267] Specific requirements include minimum surface casing requirements and minimum disposal well depths, which vary by county and are available through the KCC website. [268] Permitted well owners are required to demonstrate annually that they have the financial ability to cover the cost of closure. [269] Specific regulatory requirements implemented by the KCC are listed below: [267] [268]

- If an injection wells lies stratigraphically above the Wellington salt and the wellbore had penetrated through it the salt, then a cement plug of at least 50 feet in length, shall be placed in the borehole or casing below the injection zone and above the salt.
- Operators must report averages of injection pressures injection volumes monthly to assure that the well is operating within the authority of the permit.
- An annual report must be submitted that includes injection pressure or fluid level in the annulus for each of the 12 prior months.

- Class II wells must inject through tubing below a packer that had been placed above the uppermost perforation or open-hole interval and the annulus filled with hydrocarbon liquid or a corrosion-inhibiting fluid.
- Operator must notify any parties whose acreage lies partially or fully within a half mile-mile radius of the project boundaries.
- Each Class II injection well must undergo MIT testing; once initially prior to issue of the well permit, and afterwards, wells must pass an MIT at least once every 5 years.
- While not a regulatory requirement, the KCC reports that inspectors witness over 85 percent of MITs—substantially higher than the 25 percent requirement in federal guidelines.

Illinois

Illinois ranks fourth among U.S. states in the number of Class II wells, with about 5 percent of the U.S. total. Illinois holds primacy for UIC well Class I–Class V and maintains structural consistency with the federal regulations regarding UIC wells. The Illinois Oil and Gas Act (225 ILCS 725) regulates oil and gas operations under the Illinois Department of Natural Resources as outlined in Title 62, Chapter 1, Part 240. [270] The Illinois Administrative Code sets the application process, requirements for construction, operating and reporting, and requirements for plugging the wells under subparts C, G, and K, respectively. [271] Class II well requirements specific to EOR projects in Illinois include the following:

- Potable water wells may not be located within 200 feet, and no municipal water supply wells may be located within 2,500 feet of any proposed Class II UIC well.
- Fracture step rate test are required to accurately measure the fracture pressure of a given formation to demonstrate that fracturing of the formations will not occur at the proposed injection pressure. The maximum allowable injection pressure must be 10 percent less than the intersection safety implementation plan.
- Surface casing must be set to a depth of at least 100 feet, or 50 feet below the base of the fresh water, whichever is deeper. Casing is to be set in the presence of a Department representative.
- EOR wells must be produced through tubing and packer where the packer is set within 200 feet of the top of the producing interval and within the cemented portion of the production casing. There is a 24-hour notice to the Department prior to setting (or resetting) to allow for an inspector to be present.
- The construction requirement that the wellhead include a one-quarter-inch female fitting, with shut-off valve, to allow monitoring of the annulus. The same is required on the tubing to measure injection pressure.

Oklahoma

Oklahoma ranks fifth among U.S. states in the number of Class II wells, with about 5 percent of the U.S. total. The Oklahoma Corporation Commission's Division of Oil and Gas regulates CO_2

injection for storage in oil, gas, coal-bed methane, and mineral brine reservoirs; Class II wells are included in this group. CO_2 injection for storage in other reservoirs, such as deep saline formations, basalt reservoirs, and salt domes are regulated by the state's Department of Environmental Quality. [272] Permitting requirements applicable to CO_2 injection for geologic storage do not apply to the use of CO_2 in EOR until the well is converted from an existing enhanced recovery operation into a storage facility. [273] Title 165, Chapter 10, Subchapter 5, sections 1–15 of the Oklahoma Administrative code outlines underground injection regulations. Regulations for Class II wells used for enhanced recovery include the following:

- Operators must monitor and record the injection rate and surface injection pressure monthly.
- New or converted injection wells that are within a half mile of any public water supply well will not be approved without notice and hearing.
- Initial pressure tests must be witnessed by a representative of the Conservation Division.
- The wellhead must be constructed to include a one-quarter-inch female fitting, with shut-off valve to the tubing to measure injection pressure.

APPENDIX D: SUMMARY OF HIGH-PRODUCING CO_2 EOR PROJECTS IN THE UNITED STATES

The biennial Enhanced Oil Recovery Survey published in the *Oil & Gas Journal* demonstrates the prominence of miscible and immiscible CO_2 projects among recent EOR initiatives. [43] Exhibit D-1 below provides a summary of some of the highest-producing CO_2 EOR projects, as well as a compilation of relevant operational and geologic data. Projects featured below do not distinguish whether the CO_2 utilized is derived from an anthropogenic source or from natural CO_2 deposits.

Exhibit D-1. Summary of highly productive miscible and immiscible CO_2 EOR projects [43]

Operator	Field	State	Start Year	Number of Production Wells	Number of Injection Wells	Pay Zone	Porosity (%)	Permeability (mD)	Depth (ft)	Gravity API	Oil Saturated % Start	Oil Saturated % End	Enhanced Production (bbl/d)
CO_2 Miscible Projects													
Anadarko	Salt Creek Ph 1-8	WY	2004	321	239	Wall Creek 2 (Frontier)	18	75	1,900	37	39	24	9,000
Chevron	Rangely Weber Sand	CO	1986	378	262	Weber SS	12	10	6,000	35	38	29	8,500
Denbury Resources	Delhi	LA	2009	101	39	Tuscaloosa, Paluxy	30*	1000	3,500	42	N/A	N/A	5,920
Hess	Seminole Unit-Main Pay Zone	TX	1983	370	110	San Andres	12	1.3-123	5,300	35	84	N/A	8,150
Hess	Seminole Unit-Roz Stage1	TX	2007	44	29	San Andres	12	1.3-123	5,500	35	30	N/A	7,800
Kinder Morgan	SACROC	TX	1972	390	503	Canyon	4	19	6,700	39	78	39	28,300
Occidental	Salt Creek Ph 1-8	TX	1993	168	145	Canyon	20	12	6,300	39	89	15	6,950
Occidental	Wasson (Denver Unit)	TX	1983	1073	594	San Andres	12	8	5,200	33	51	31	24,441
Occidental	Wasson (ODC Unit)	TX	1984	329	321	San Andres	10	5	5,100	34	49	34	7,617
Occidental	Wasson (Willard Unit)	TX	1986	327	237	San Andres	9	2	5,100	32	56	41	6,567
CO_2 Immiscible Projects													
Denbury Resources	Eucutta	MS	2006	55	49	Eutaw	27	250	5,050	22	42	N/A	2,810
Denbury Resources	Tinsley	MS	2007	122	47	Woodruff	23	500	5,000	34	30	N/A	9,640
Denbury Resources	Heidelberg, West	MS	2008	122	47	Eutaw	28	300	4,800	22	37	N/A	6,430
Kinder Morgan	Yates	TX	2004	606	123	San Andres	17	175	1,400	30	75	54	15,000

*Listed as 0.3 in the 2014 Oil & Gas Journal Special Report: 2014 Worldwide EOR Survey and assumed to be 30 percent.

APPENDIX E: IMPORTANCE OF SWEEP AND DISPLACEMENT EFFICIENCY ON A POTENTIAL CO_2 EOR PROJECTS

Residual oil recovery efficiency (E_R) is critical in understanding the potential outcome of a CO_2 EOR endeavor. E_R is a measure of the potential effectiveness of an EOR process and consists of two components: 1) volumetric sweep efficiency, which is a measure of the reservoir contacted by injected fluid, (E_V); and 2) displacement efficiency (E_D), which is the fraction of moveable oil that has been recovered at the pore level from the swept zone (by either CO_2, waterflood, or other displacement process). [30] [274] Equation E-**1** below mathematically depicts the recovery efficiency concept.

$$E_R = E_D \times E_V$$ *Equation E-1*

Where:

E_D = displacement efficiency (decimal)
E_v = volumetric sweep efficiency (decimal)

Both E_V and E_D are dependent on site-specific geologic factors. For instance, displacement efficiency is a function of reservoir pressure and temperature, the composition of oil, CO_2/water slug size, mobility ratio, rock wettability, rock-pore geometry, and structure. Factors influencing volumetric sweep efficiency include well injection pattern (5-spot, 9-spot, etc.) naturally occurring fractures, the position of oil, gas, and water contacts, formation permeability and heterogeneity, fluid densities (between CO_2, water, and oil), mobility ratio, and overall flow rate. [30] [274]

Residual oil saturation and water saturation effect the overall recovery efficiency due to their direct impact on displacement efficiency. Equation E-2 provides further insight into the effects of different oil and water saturations on displacement efficiency, where any increase in water saturation (S_w), and subsequent decrease in residual oil saturation (S_{or}) leads to increased displacement efficiency. [30]

$$E_D = \frac{1 - S_{wi} - S_{or}}{1 - S_{wi}}$$ *Equation E-2*

Where:

S_{wi} = the initial or connate water saturation (decimal), where $1 - S_w$ is the volume of oil at the start of the flood S_{orw} = the residual oil saturation or unswept oil from waterflooding (decimal),

Volumetric efficiency, $E_{V,}$ is a product of both areal sweep efficiency (E_A) and vertical sweep efficiency (E_I), as shown in Equation E-3. [30] [274]

$$E_V = E_A \times E_I$$ *Equation E-3*

Where:

E_A = areal sweep efficiency (decimal)
E_I = vertical sweep efficiency (decimal)

The areal sweep efficiency is defined as the fraction of the pattern area from which reservoir fluid is displaced by the injected phase and is influenced by the dip angle and dip azimuth of the injection formation, presence of fractures, mobility ratio, injection pattern, and directional permeability. The vertical sweep efficiency is the ratio of the cumulative height of the vertical sections of the pay zone that are contacted by injection fluid to the total vertical pay-zone height and is subject to the density difference between the injected and resident fluid phases, mobility ratio, total volume of fluid injected, the vertical permeability of each zone, and the permeability contrast between different pay zones. [30] [274]

The relationships presented in this appendix provides insight into a few of the more critical reservoir parameters dictating the potential recovery of residual oil in place, agnostic from the displacement mechanism (e.g., miscible CO_2, immiscible CO_2, waterflooding, or another displacement approach). These parameters are accounted for by the E_I, E_A, E_D, and E_V terms described in the equations above for which they influence. Field operators must be able to optimize the variables defining these terms to successfully conduct an effective CO_2 EOR treatment.

APPENDIX F: OVERVIEW OF THE UNITED STATES DEPARTMENT OF ENERGY METHODOLOGY FOR ESTIMATING GEOLOGIC STORAGE POTENTIAL FOR CARBON DIOXIDE

The United States (U.S.) Department of Energy (DOE) methodology is intended for external users, such as the Regional Carbon Sequestration Partnerships, future project developers, and governmental entities, to produce high-level carbon dioxide (CO_2) resource assessments of potential CO_2 storage reservoirs in the United States and Canada at the regional and national scale; however, the methodology is general enough to be applied globally.[r] DOE's methodology was used to evaluate three types of storage formations: oil/gas reservoirs, saline formations, and unmineable coal seams. The saline formation methodology was assessed at the basin level and is the focus of this appendix. [181] The general methodology for saline-bearing formation capacity is provided below.

Saline formation CO_2 storage resource estimating:

The volumetric equation to calculate the CO_2 storage resource mass estimate (G_{CO2}) for geologic storage in saline formations is shown in Equation F-1:

$$G_{CO2} = A_t \times h_g \times \phi_{tot} \times \rho \times E_{saline} \qquad \textit{Equation F-1}$$

Where:

- A_t = area that defines the basin or region being assessed ($Length^2$)
- h_g = gross thickness of saline formation within A_t (Length)
- ϕ_{tot} = total porosity in volume defined by thickness ($Length^3/Length^3$)
- ρ = density of CO_2 evaluated at pressure and temperature at depth ($Mass/Length^3$)
- E_{saline} = CO_2 storage efficiency factor ($Length^3/Length^3$)

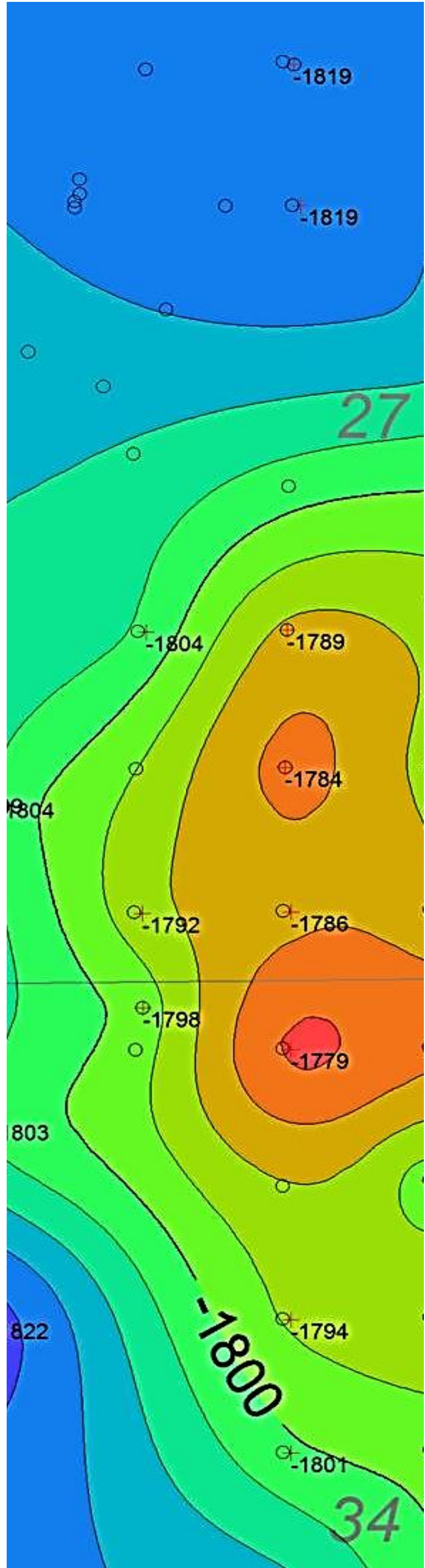
[r] The DOE methodology can be found at https://www.netl.doe.gov/File%20Library/Research/Carbon-Storage/Project-Portfolio/Goodman-Paper.pdf.

APPENDIX G: SELECTED CHARACTERISTICS OF CARBON CAPTURE AND STORAGE PROJECTS WORLDWIDE

Exhibit G-1 provides a list of ongoing or recently completed carbon capture and storage (CCS) projects in the United States (U.S.) and *internationally* focusing on saline storage projects. This list features key parameters (that pertain to critical criteria like injectivity, capacity, and containment) that all successful geologic CO_2 projects possess. This list supplies a comparative analysis of each project's geologic properties, depth, and injection volume.

Exhibit G-1. Worldwide CCS projects list

Project Name	Location	Storage Formation	Storage Formation Depth (Below ground surface)	Porosity (%)	Permeability (millidarcy)	CO_2 Injection Rate/Volume	Status	Reference
U.S.-Based CCS-Related Projects								
Midwest Geological Sequestration Consortium Illinois Basin Decatur Project	Decatur, Illinois, United States	Mount Simon Sandstone	5,545 feet	15-25	10-1,000	0.33 Mt/yr, 1 Mt total	Completed November 2014	[211] [275]
Southeast Regional Carbon Sequestration Partnership Cranfield Project	Natchez, Mississippi, United States	Lower Tuscaloosa Sandstone	8,500 feet	25	50-1,000	1.5 Mt/yr, 5.37 Mt total	Completed January 2015	[276]
Illinois Industrial Carbon Capture and Storage Project	Decatur, Illinois, United States	Mount Simon Sandstone	7,000 feet	20	26	1 Mt/yr	Active	[277]
Internationally-Based CCS-Related Projects								
Snøhvit CO_2 Storage Project	Barents Sea, Norway	Saline Tubasan Sandstone Formation	8,530 feet	10-16	130-890	0.7 Mt/yr	Active	[277] [278]
Sleipner Project	North Sea, Norway	Utsira Formation	2,297-3,281 feet	24-40	1,000-3,000	0.9 Mt/yr	Active	[277] [278]
Gorgon Storage Project	Onshore Barrow Island, Australia	Dupuy Formation	7,476 feet	22	25-100	3.4-4.0 Mt/yr	Active	[7] [279]
In Salah CCS Project	Algeria	Krechba Formation	5,900-6,230 feet	17	2.5-10	1-1.2 Mt/yr, 3.8 Mt total	Injection suspended in June 2011	[7] [277] [280]
Nagaoka	South Nagaoka, Japan	Pleistocene Haizume Formation	2,624-3,937 feet	22.5	6	40 tonnes/day, 0.01 Mt total	Completed in 2010	[280] [281]
Quest	Alberta, Canada	Basal Cambrian Sand	6,560 feet	16	20-500	1 Mt/yr	Active	[7] [282]
Aquistore	Saskatchewan, Canada	Deadwood and Black Island Formations	11,155 feet	11-17	100-1,000	1,600 tonnes/day	Active	[283] [284]



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