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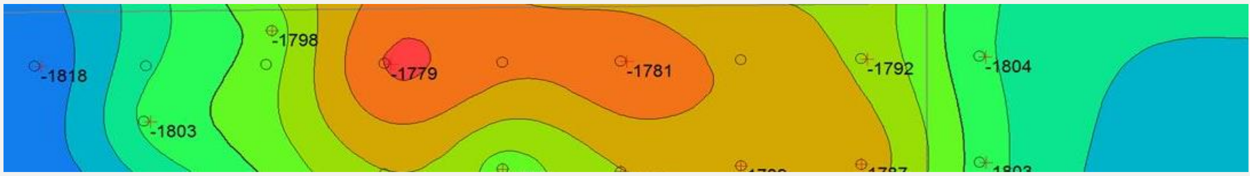

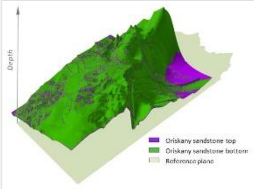

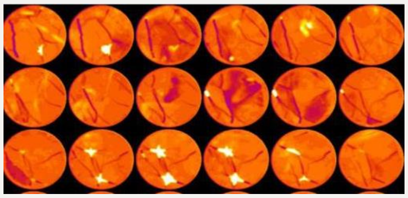

UIC Class I Injection Wells – Analog Studies to Geologic Storage of CO_2

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ACRONYMS AND ABBREVIATIONS

2-D	Two-dimension, two dimensional
3-D	Three-dimension, three dimensional
ADM	Archer Daniels Midland Company
AMA	Active monitoring area
AoR	Area of review
bbl	Barrel
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	Carbon capture and storage
CFR	Code of Federal Regulations
CO_2	Carbon dioxide
cP	Centipoise
CSC	California Specialty Cheese
D	Darcy
d	Day
DOE	Department of Energy
DWTR	Drinking water residuals
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
FE	Fossil energy
ft	Foot, feet
ft^3	Cubic feet
gal	Gallon, gallons
GAO	General Accounting Office
Gt, Gtonne	Gigatonnes
GHG	Greenhouse gas
HSWA	Hazardous and Solid Waste Amendments
IBDP	Illinois Basin-Decatur Project
ICCS	Illinois Industrial Carbon Capture and Storage Project
IEA	International Energy Agency
K.A.R.	Kansas Administrative Regulations
KDHE	Kansas Department of Health and Environment
l	Liter
LAC	Louisiana Administrative Code
lb	Pound
LDFA	Land Disposal Program Flexibility Act
LDR	Land disposal restrictions
LNG	Liquefied natural gas
mD	Millidarcy, millidarcys
MESA	Mission Execution and Strategic Analysis
mg	Milligram
mi	Mile, miles
MIT	Mechanical integrity test/testing
MMA	Maximum monitoring area
MMgal/d	Million gallons per day
MMI	Modified Mercalli intensity
MRV	Monitoring, reporting, and verification
Mt	Million tonnes
Mt/yr	Million tonnes per year
Mt.	Mount
MVA	Monitoring, verification, and accounting
NATCARB	National Carbon Sequestration Database and Geographic Information System
ND	Not developed
NETL	National Energy Technology Laboratory
NTW	National Technical Workgroup
PADER	Pennsylvania Department of Environmental Resources
PISC	Post-injection site care
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch absolute
R&D	Research and development
RCRA	Resource Conservation and Recovery Act
RCSP	Regional Carbon Sequestration Partnership
ROW	Right-of-way
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
TAC	Texas Administrative Code

TCEQ	Texas Commission on Environmental Quality
TDS	Total dissolved solids
tonne	Metric ton (1,000 kilograms)
TSDF	Treatment, storage, and disposal facility
U.S.	United States
UIC	Underground Injection Control
UIPC	Underground Injection Practices Council
USDW	Underground source of drinking water
USGS	United States Geological Survey
WAP	Waste analysis plan
yr	Year, years
ZEI	Zone of endangering influence
°C	Degrees Celsius
°F	Degrees Fahrenheit

EXECUTIVE SUMMARY

The purpose of this report is to compile a stand-alone body of knowledge regarding historical and current operations of subsurface waste disposal (i.e., deep well disposal of hazardous and non-hazardous waste) using the United States (U.S.) Environmental Protection Agency (EPA) Underground Injection Control (UIC) Class I injection wells, as well as document information pertaining to Class I well leakage that may have occurred as part of those operations, that may be directly or indirectly relevant to geologic carbon dioxide (CO_2) storage in saline-bearing formations. This is the second of three planned reports that evaluate analog industries of CO_2 storage (the first focuses on underground natural gas storage, and the third on CO_2 enhanced oil recovery [EOR]). UIC Class I wells are used to inject hazardous and non-hazardous wastes into deep geologic formations below the lowermost underground source of drinking water (USDW). Underground storage formations are selected that are porous and have relatively impermeable confining rock layers above and below injection intervals to prevent migration of the injected fluid outside of the intended injection zone. The technologies and equipment used to deploy waste disposal parallel those needed for geologic storage of CO_2 in saline-bearing formations (and essentially full-scale carbon capture and storage [CCS]). For instance, the two practices face similar technical grand challenges associated with using wells to safely and effectively inject waste or CO_2 into deep, porous geologic formations; but they do so under different UIC well classes, particularly Class I injection wells for waste disposal and Class VI injection wells for CO_2 storage. 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 injecting/disposing/storing waste or CO_2 in the subsurface safely and effectively. Therefore, deep well waste disposal 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.

Subsurface disposal via injection wells has become a popular method for organizations to dispose of liquid waste when other options are either not possible or excessively costly, and is considered to have fewer environmental impacts than surface disposal applications. [1] The basic practice involves using an injection well to place fluid underground into porous geologic formations. The widespread use of injection wells began in the U.S. in the 1930s to dispose of brine generated during oil production. By the 1950s, chemical companies began disposing of industrial wastes via deep injection wells; and as chemical manufacturing increased, so did the use of deep well injection. [2] Since then, the number of hazardous and non-hazardous waste injection wells (currently regulated as UIC Class I injection wells) have become even more widespread and increased to 817 (137 of which are hazardous) as noted in a 2017 well survey. [3] The U.S. EPA did not create the UIC Program Class I regulations until 1980 after broader adoption of subsurface waste disposal practices via deep well injection in tandem with several cases of well failures resulting in leakage (prominent examples include the Hammermill Paper Company's No. 1 well in Erie, PA in the 1960s, and the Velsicol Chemical Company well in Beaumont, TX in the 1970s) had occurred. Since the creation of the UIC Program and Class I wells, there have not been any reported cases of USDW contamination. Class I wells are specifically designed, constructed, and completed with the intent to prevent the movement of fluids that could result in the pollution of a USDW or leakage to the surface. [4] 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. [5] 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 waste disposal via deep well injection, 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 I 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 [6] Therefore, from a regulatory perspective, both Class I 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 deep well waste disposal operations in the United States provides a unique opportunity to examine injection well evolution and operations in order to: 1) gain insight and lessons learned associated with waste disposal; 2) draw parallels to the subsurface injection governing regulations associated for waste disposal 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 deep well waste disposal has demonstrated that large volumes of waste 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. [7] 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. [8] 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. [9] 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. [9] [10] 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., deep well waste disposal) 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, leakage mitigation strategies, etc.) between Class I waste injection well operations and CO_2 storage in saline-bearing formations using UIC Class VI wells. The findings suggest that Class I waste injection 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 I and Class VI wells share several risks related to the injection/disposal and injection/storage of waste and CO_2, respectively. Because of these shared risks, both types have comparable well design requirements and may utilize similar equipment, including pumps, wells, and monitoring equipment, despite injecting different fluids. [4] [11] [12] Site operators for both Class I and Class VI wells must ensure that geologic reservoirs utilized at injection sites have the necessary capacity for disposal or storage, have sufficient injectivity to introduce the waste or CO_2 into the formation at the desired rate, have sufficient confining 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 a 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. [13] 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). [14] 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.

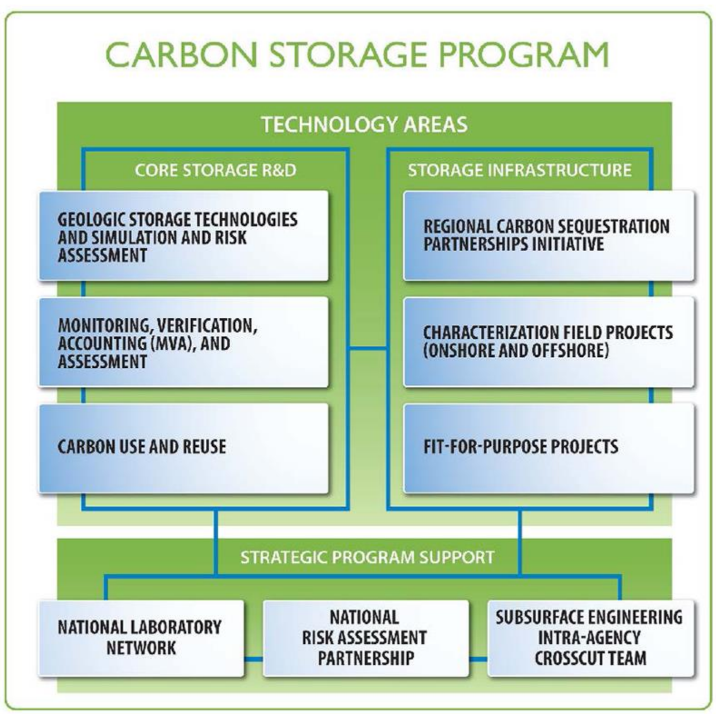
Suitable geologic storage formations can exist in both onshore and offshore settings, and each type of geologic formation presents different opportunities and challenges. [15] While the technologies required for CCS are at various stages of commercial readiness and only a few fully integrated projects 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. [16]

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). [15] 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. [15] 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. [17]

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. [15] [16] 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 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. [18]

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. [10] 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. [9] 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) [10] 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. [10] 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 [19] [20] 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 [5] and Rai et al. [10] 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 [21] 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); [20] 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 proven, and 3) informs relevant legislative and regulatory actions. [10] [20] 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 in 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. [21] 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 [22], 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. [23]

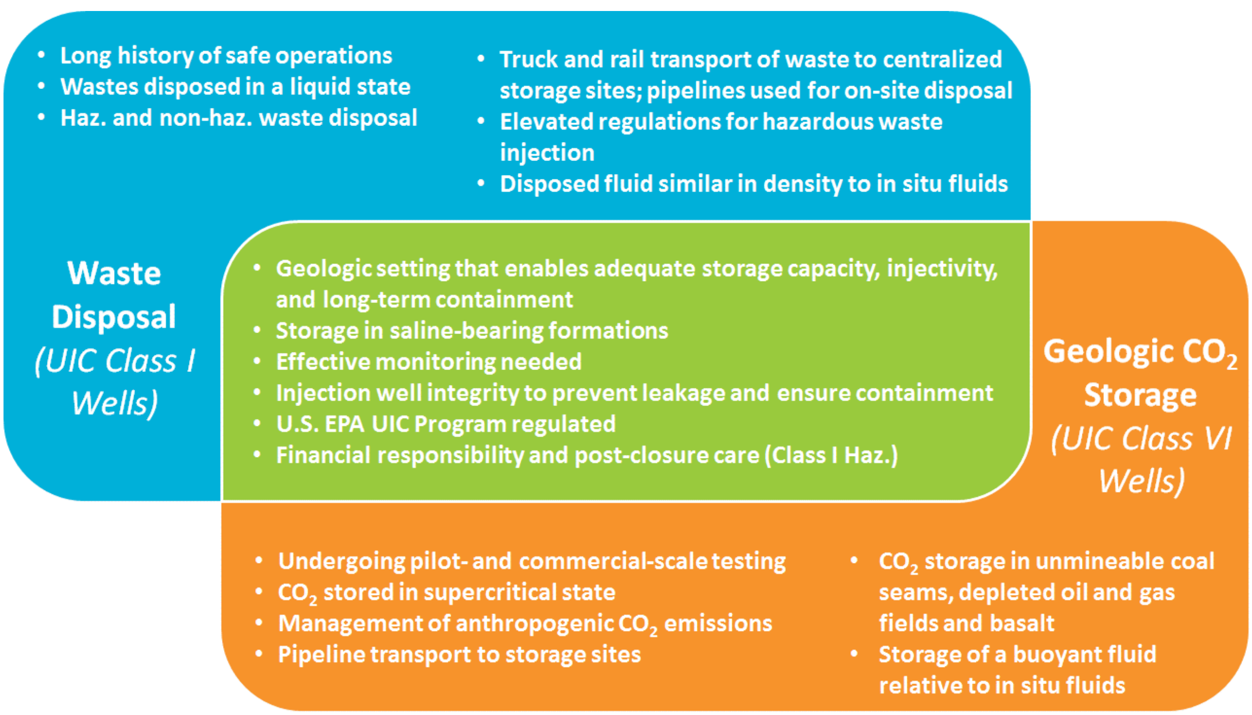
This report focuses on waste disposal via deep well injection and geologic CO_2 storage in saline-bearing formations; both individually and in relation to each other. Deep well disposal of hazardous and non-hazardous waste (regulated under U.S. EPA Underground Injection Control [UIC] Class I regulations) was chosen as an analog to long-term geologic CO_2 storage (regulated under EPA UIC Class VI regulations) because of the similar processes used in injecting either waste or CO_2 deep into the subsurface. Additionally, for both practices, similarities exist in terms of site selection and characterization criteria, as well as operational procedures, and the infrastructure needs. Additionally, the extensive operational history of deep well waste disposal 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 U.S. EPA UIC Class I injection well program operations, which may relate directly or indirectly to CO_2 geologic storage operations in saline-bearing reservoirs. The second objective is to document site screening and selection methods, site characterization, and operating procedures that may also be relevant to future CO_2 storage operations. Best practices and lessons learned from the history of Class I well operations, as well as deep well disposal prior to enactment of EPA's UIC Program, in the United States 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 overcame shared technical grand challenges (like those associated with identifying and ensuring injectivity, capacity, and containment throughout operations) and addressing 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 Class I well operations and historic deep well disposal practices prior to Class I regulations into a USDW, particularly hazardous waste. While relatively few, there have been noted historical cases of leakage associated with deep well disposal operations prior to creation of the UIC Program or Class I wells (examples documented and analyzed in Section 6). Understanding the remedial actions that worked (as well as those that may have not been successful) in response to any leakage events is also of importance. The last objective is to provide documentation of instances of public interaction concerning the development or operation of Class I sites to provide insights into issues that might potentially arise during the development of a Class VI CO_2 storage well.

Class I injection wells, applied in industries such as petroleum refining and metal production, are used to inject and dispose of hazardous and non-hazardous wastes into deep confined rock formations well below the lowermost USDWs. [24] The practice of deep well injection is considered inexpensive and requires little or no pretreatment of the waste; however, it poses a threat of leaking hazardous waste and eventually polluting subsurface water supplies. [25] In 1980, the U.S. EPA promulgated the UIC regulations to ensure proper construction and operation of injection wells for disposal of liquid hazardous and non-hazardous waste. Since establishment of the UIC regulations, which require implementation of stringent siting, construction, operation, and testing requirements for injection wells, only four significant cases of injectate migration occurred from hazardous injection well operations; none of which affected drinking water sources in the long-term. Injection of hazardous and non-hazardous waste into Class I injection wells since 1980 has been, and continues to be, a low-risk method of liquid waste management that has proved to be safe and effective. [26] A 2017 inventory for the United States showed 817 Class I wells of which 137 were classified as hazardous. Most of these hazardous wells were in Texas (57 percent of all hazardous wells) and Louisiana (14 percent of all hazardous wells). [3]

As mentioned in the preceding text, deep well disposal operations are very analogous to CO_2 storage operations in saline aquifers. Specifically, there are several similarities between Class I and Class VI wells including the types of injection wells and surface equipment used for injection and regulations regarding well integrity, monitoring of leakage, well siting, financial responsibility, and post-closure care. On the other hand, 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 deep well waste disposal using UIC Class I wells and geologic CO_2 storage using Class VI wells



While several similarities and overlap between deep well waste disposal and CO_2 storage in saline reservoirs exist, there are major differences, which include varying levels of commercial application and experience of each practice, the types and physical state of the injected fluids, the relative volume of injected material, and the specific UIC well class and robustness of governing regulations (Class I hazardous wells have additional and more stringent regulatory requirements than non-hazardous wells and could provide the best analog to the highly-stringent UIC Class VI wells specific to geologic storage of CO_2). The similarities and differences between these two practices are further compared in the sections below. The critical findings from the experience of waste disposal 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 deep well waste disposal operations has been achieved, so that CO_2 storage best practices can be developed and implemented.

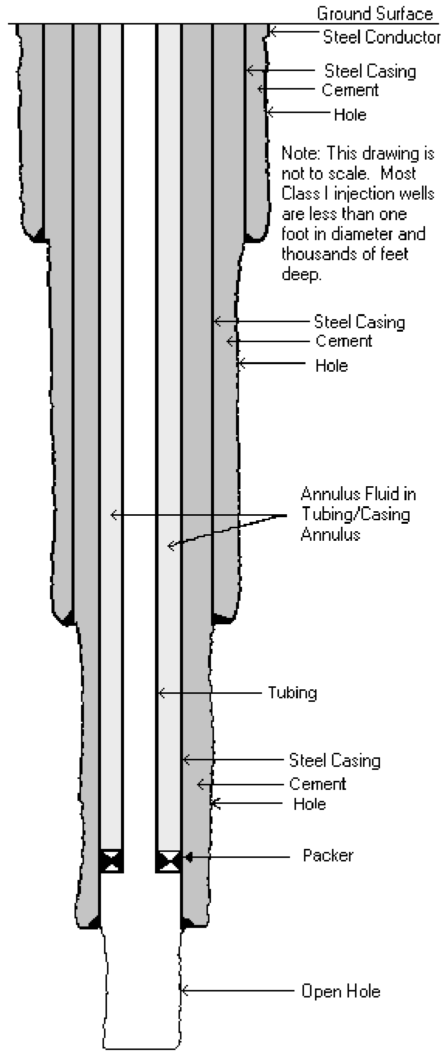
2 SUBSURFACE WASTE DISPOSAL HISTORY AND OVERVIEW

Subsurface liquid waste disposal via deep well injection involves the injection of liquid waste material into isolated geologic strata through a well, which, in turn, permanently isolates the disposed fluids from the biosphere. [26] Subsurface injection of liquid waste is used as a disposal method throughout most of the United States. It is used particularly when other liquid waste management approaches (such as treatment prior to surface discharge) are either not possible or too costly. [1] EPA has indicated that waste disposal wells have been an effective management option injected upwards of approximately 11 percent of the nation's fluid waste. [27] The effective management of liquid waste could become more challenging in the future if quantities increase due to continuing urban, agricultural, and industrial growth, as well as if additional types of hazardous wastes are generated. [1] Subsurface disposal via deep well injection may provide the best direct and effective means for managing liquid waste especially if volumes increase. The challenge to this approach is that favorable geologic and hydrogeologic conditions must be available to engage in such an undertaking. There is a long history of subsurface liquid waste disposal practices using wells in the United States, which provides insight into lessons learned associated with the evolution of operations, emergence and progression of governing regulations related to subsurface injection, and best practices for overcoming critical technical challenges. This section introduces the history of subsurface liquid waste injection wells for the purposes of waste disposal, as well as an introduction and overview of the emergence of UIC Class I well regulations for disposal of hazardous and non-hazardous waste.

2.1 SUBSURFACE INJECTION FUNDAMENTALS

Subsurface injection involves forcing liquid through a wellbore into an underground rock formation that is generally filled with water and has substantial pore space. Injection zones are typically brine-saturated formations or non-freshwater zones. Subsurface injection may utilize gravity injection where the hydrostatic weight of the injected fluid displaces the in-situ formation fluid, or if the hydrostatic weight of the injected fluid is not great enough, then pressurized injection involving pumps is used to add the necessary force to drive in situ water out of the pore space. [1] In the United States (following the establishment of the UIC Program in 1974), newer disposal wells that inject wastes are designed, constructed, and completed with the intent to prevent the movement of fluids that could result in the pollution of a USDW. [4] Since enactment of initial UIC regulations in 1980, wells tend to contain common design features critical to safe and effective injection (Exhibit 2-1). They are typically lined with a casing and cement to the desired injection depths to prevent the collapse of the well, and prevent outflow of the injected liquid, as well as to provide maximum protection of USDWs and fresh groundwater resources. The innermost layer of the well, the injection tubing, guides injected waste from the surface to the injection zone. The annular space between the tubing and the long string casing, which is typically sealed at the bottom by a packer and at the top by the wellhead, isolates the casing from injected waste and creates a fluid-tight seal. The packer is a mechanical device set directly above the injection zone that isolates the outside of the tubing from the inside of the long string casing. [28]

Exhibit 2-1. Example schematic of an open-hole injection well featuring key well components [29]



Source: U.S. EPA

The characteristics of the receiving formation (i.e., injection zone) determine the appropriate well completion assembly. For instance, wells constructed in unconsolidated sand and gravel-type strata may be equipped with a perforated casing or screen at the end of the casing to facilitate fluid injection without the risk of borehole cave-ins. Wells constructed in consolidated rock with minimal risk of cave in, like sandstones and limestone, can be designed with an unlined borehole injection interval below the casing, known as an open-hole completion. [1]

For subsurface waste injection to be successfully and safely operated, candidate injection sites and the surrounding subsurface region must contain several hydrogeologic characteristics, including: [1]

- Formation attributes, particularly favorable geometry and hydraulic properties like permeability, within the injection zone that enable fluid injection at a suitable rate and at pressures that will not induce fracturing

- A sufficiently extensive injection formation to accommodate the total waste volume
- Possession of confining zones above and below the injection interval to prevent fluid movement to other formations
- Liquid waste chemistry that is compatible with the chemical composition of the native rocks and water to prevent reactions that can damage confining zones or the well components (like cement and casing)
- Conduits for potential leakage (like improperly abandoned wells or transmissive faults and fractures) are absent from the injected liquid plume area

The geologic considerations mentioned in the bullets above are critical to successful liquid waste disposal operations and offer final safeguards against the movement of injected wastewaters to a potential USDW. Typically, extensive pre-siting geological tests confirm that the injection zone is of sufficient quality to accommodate waste disposal prior to well installation. [28]

2.2 HISTORICAL PERSPECTIVE OF DEEP WELL WASTE DISPOSAL

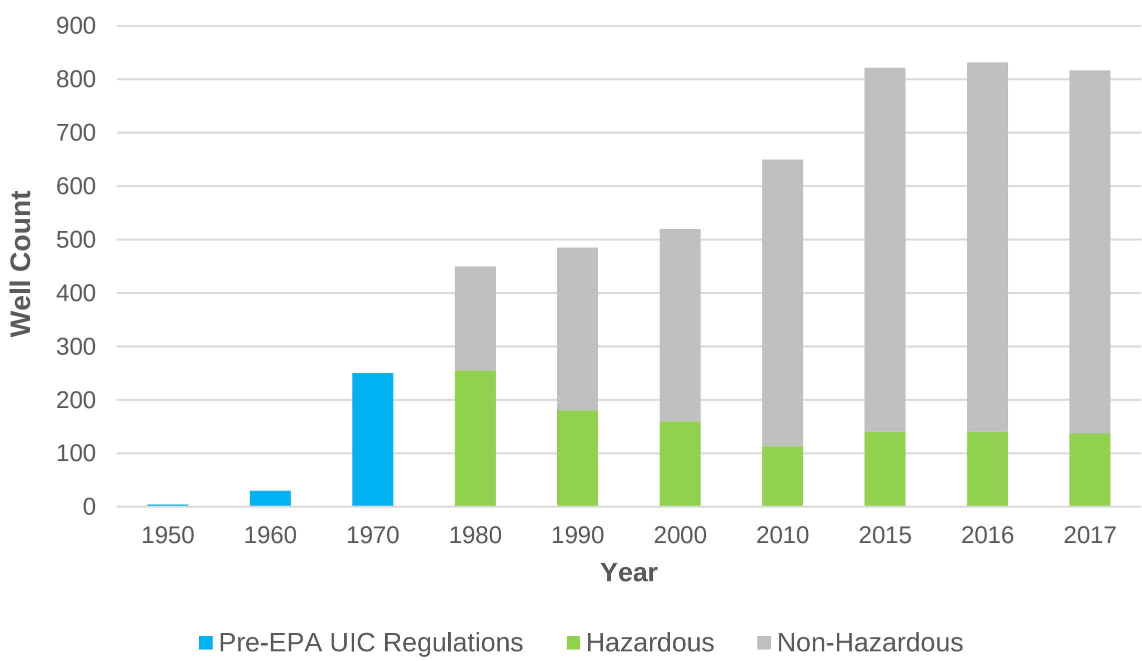
The disposal of liquids into the subsurface began during the 1930s when oil and gas companies would inject brine (high salinity water) produced during gas and/or oil extraction back into depleted reservoirs. Most of the early injection wells were oil production wells converted for wastewater disposal. [28] Prior to subsurface disposal, produced brine was discharged directly into surface water, like streams and rivers. In general, subsurface disposal wells were deep in nature, and since the injection zones were depleted reservoirs that had trapped natural gas and oil over extended periods, waste containment was likely to be achieved. However, attempts at shallower industrial waste injection (one such example occurred in an 800-foot (ft)-deep sand formation) in the mid-1930s were quickly stopped as injected fluid found its way back to the surface through other wells that had penetrated the injection zone. [30]

The deep subsurface waste disposal concept was later applied to liquid industrial wastes in the early 1950s. The first deep industrial injection well was drilled by DuPont in Texas in 1949, followed by injection operations the following year. [26] Restrictions were placed on the disposal of wastes into surface waters or onto land after the enactment of federal and state environmental laws, which resulted in an increase in the use of underground injection for the disposal of liquids. [31] Subsurface disposal became popular among companies looking to dispose of liquid waste when other options were either not possible or too cost prohibitive. [1] In addition to the cost benefits, subsurface injection was considered less environmentally impactful compared to surface disposal, which has a significantly greater potential to damage freshwater resources. Subsurface injection was quickly adopted by other industries—including chemical and manufacturing—aiming to lower costs associated with waste disposal. In the 1950s, four injection wells were reported in the United States; by the early 1960s, there were 30 reported injection wells. [26] Despite the increase in subsurface waste disposal activity, regulations (typically a state responsibility during this time) were not being implemented at the same pace. Additionally, the practice of subsurface injection of waste was not well understood by many state and local governmental officials responsible for developing these types of waste disposal regulations. [26] By the early 1970s, the number of injection wells had reached nearly 250, [32] a substantially larger jump from the count in the 1960s. As indicated by Exhibit 2-2, subsurface waste disposal operations have continually increased through 2016. The spike in subsurface injection activity from the 1960s through the 1970s, and subsequent avoidance of surface waste treatment requirements, attracted the attention of the U.S. EPA. Furthermore, noted cases of well failures associated with subsurface waste disposal had occurred, including:

- In the late 1960s (associated with corrosion of well casing at Hammermill Paper Company's No. 1 well in Erie, PA)
- In the early/mid 1970s (associated with casing leaks in a Velsicol Chemical Company well in Beaumont, TX) [26] [28]

In 1974, EPA issued a policy statement that was a direct response to concerns about underground injection practices. EPA stated that underground injection could not occur "without strict control and clear demonstration that such wastes will not interfere with present or potential use of subsurface water supplies, contaminate interconnected surface waters or otherwise damage the environment." Also in 1974, U.S. Congress enacted the Safe Drinking Water Act (SDWA), which required EPA to set requirements for protecting USDWs, as well as standards for maximum contaminant levels in drinking water. The SDWA has been amended several times since enactment.

Exhibit 2-2 Number of disposal wells active at the start of each decade* [3] [26] [33] [34] [35]



*While not the start of a new decade, wells documented in years 2015, 2016, and 2017 are to provide additional reference points for disposal well trends. Wells post-1980 include UIC Class I hazardous and non-hazardous wells only.

The SDWA addressed issues from a national perspective and included all forms of injection wells at the time. Additionally, the SDWA established requirements and provisions for the UIC regulations. There are several sections of the SDWA that are specific to subsurface injection and they are listed in Appendix B: Relevant Safe Drinking Water Act Underground Injection Control Requirements. EPA and state agencies conducted detailed reviews of subsurface injection operations ongoing during the 1970s. Findings and lessons learned from these reviews were incorporated into the final UIC regulatory requirements. These regulations were ultimately implemented to protect current and potential drinking water sources with less than 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) (i.e., USDW). [26] EPA promulgated the UIC regulations in 1980 based on the idea that properly constructed and operated injection wells are a safe mechanism for disposing of liquid waste. The 1980 UIC regulations categorized injection wells into five classes (further described in Section 3) and established technical requirements for siting, construction, operation, and closure of injection wells.

Exhibit 2-3 provides a timeline of key events in the operational and regulatory history associated with subsurface liquid waste disposal.

Exhibit 2-3 Timeline of critical events associated with underground fluid disposal [26] [36]

Year	Event
1930	Petroleum industry begins injecting brine into subsurface
1935	Dow Chemical Company injects brine into shallow industrial well
1949	DuPont drills the first deep industrial injection well
1961	Texas becomes first state to enact injection regulations
1968	Casing corrosion at Hammermill Paper Company's No. 1 well resulting in pulping liquor to flow into Lake Erie and onto land
1970	EPA implements the Subsurface Emplacement Policy aimed at protecting the subsurface environment from pollution associated with improper injection well design and prohibit ill-sited wells
1972	The Federal Water Pollution Control Act Amendments are enacted*
1974	The SDWA established giving EPA authority to oversee underground injection to protect USDWs
1974-75	Velsicol Chemical Company noted that wastewater had leaked to USDWs from one of their injection wells designed without tubing
1976	Resource Conservation and Recovery Act passed into law
1980	First U.S. EPA UIC regulations promulgated
1982-84	State primacy programs; U.S. EPA directs implementation
1984	Hazardous and Solid Waste Amendments with Land Disposal Ban
1985	Report to Congress on Injection of Hazardous Waste
1988	EPA No-Migration Exemption Regulations
1989	EPA Office of Solid Waste and Emergency Response Comparative Risk Project
1991	Report to Congress on restrictions of deep injection of hazardous waste
1993	EPA issues report analyzing trends of non-hazardous and hazardous Class I mechanical integrity failures in selected states occurring in the 1988 to 1991 timeframe [37]
1996	Land Disposal Program Flexibility Act
1998	EPA issues second report analyzing trends of non-hazardous and hazardous Class I mechanical integrity failures in selected states occurring between 1993 and 1998 [38]
2001	Report to Congress on Land Disposal Program – Study of the Risks Associated Underground Injection Wells

*Oil and gas-related liquid wastes were exempt from federal control because they were not classified as pollutants under the 1972 amendments. [26]

Since establishment of the UIC regulations in 1980, only four significant cases of injectate migration occurred due to hazardous well operations; none of which affected drinking water sources following aquifer remediation efforts. [28] This is believed to be attributed to the stringent siting, construction, operation, and testing requirements for Class I hazardous and non-hazardous wells. EPA has indicated in the 2001 *Study of the Risks Associated with Class I Underground Injection Wells* that the few instances of contamination associated with subsurface waste disposal via deep well injection prior to 1980 would not have occurred had the 1980 regulations been in place. Injection of hazardous and non-hazardous waste into Class I injection wells since 1980 has been, and continues to be, a low-risk method of liquid waste management that has proved to be safe and effective. [26]

The UIC Program initially consisted of five, which would later be adjusted to six, well classes. Each well class has its own regulations and requirements along with a specific fluid type that should be injected. Class I injection wells, which is the focus of this report, are used to inject hazardous and non-hazardous fluids into deep formations below the lowermost USDW. The following sections describe the Class I injection well and provide an overview of typical target zones, national inventory, and the potential risks.

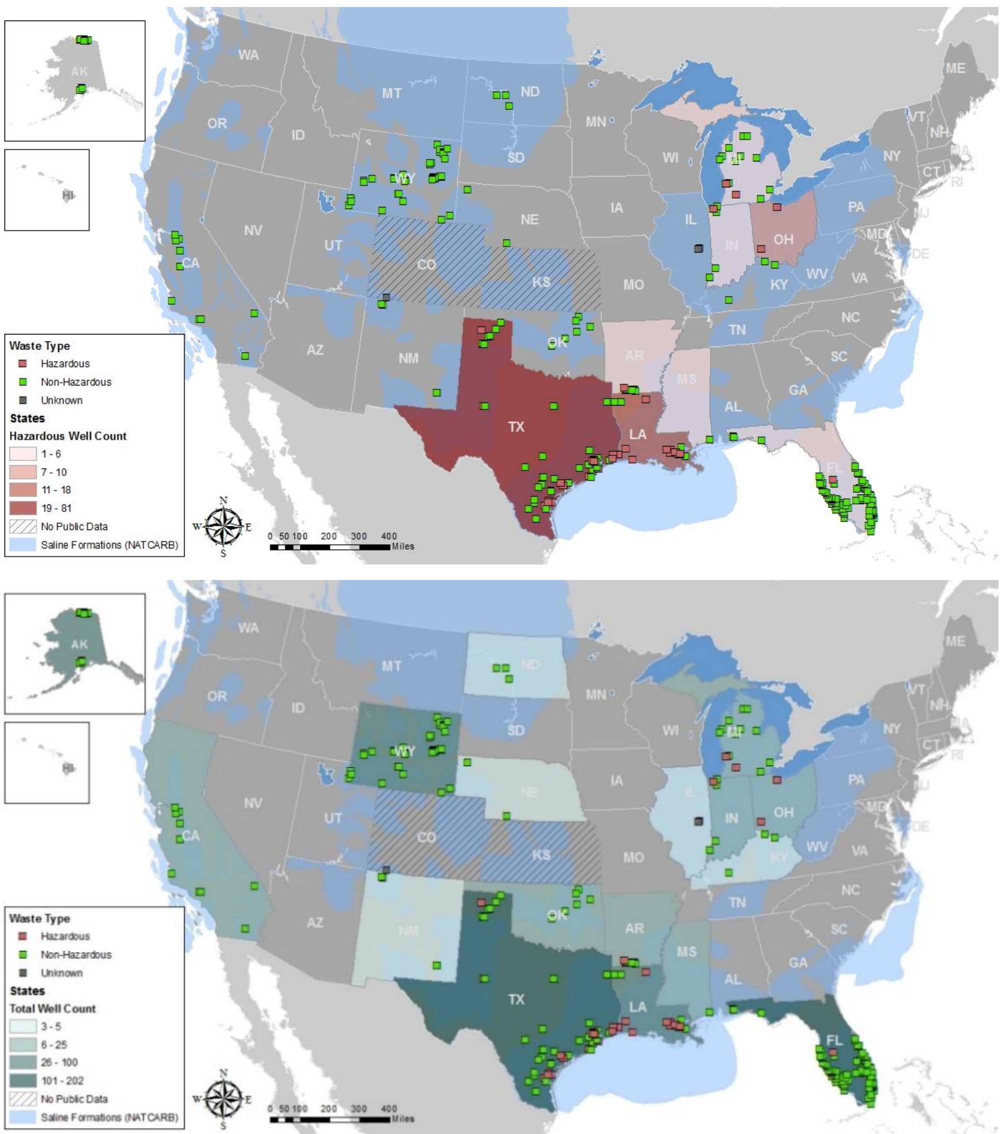
2.3 UIC CLASS I INJECTION WELL INTRODUCTION

As previously mentioned, the purpose of Class I injection wells is to inject industrial fluids or municipal wastewater beneath the lowermost USDW; Class I injection wells are designated as hazardous or non-hazardous depending on the type of fluid injected. The U.S. EPA's siting, construction, operating, testing, monitoring, and closure requirements for Class I injection wells are intended to provide multiple safeguards against well leakage or the movement of injected fluids into USDWs. Fluids injected into Class I wells have historically been associated with industries that produce chemical and metal products, as well as refine petroleum. Sources indicate that historic injection volumes for Class I wells have ranged less than one to over 19 million gallons per day (MMgal/d). [28] [39] According to the U.S. EPA, target injection zones for Class I wells are typically brine-saturated formations (i.e., saline-bearing formations) [28] and can range anywhere from around 1,700 ft to over 10,000 ft below the ground surface. [24] There are four subcategories that can be used to further describe Class I wells according to the U.S. EPA based on the characteristic of fluid injected: [24]

- **Hazardous waste disposal wells**: These wells inject waste deemed as hazardous under the Resource Conservation and Recovery Act (RCRA) and are governed by more rigorous regulations concerning well construction, operation, and monitoring than non-hazardous Class I wells. Most Class I hazardous waste wells are located at industrial facilities and dispose of waste generated onsite. Much of the waste is pretreated to remove suspended solids or adjust the pH prior to injection.
- **Non-hazardous industrial waste disposal wells**: These wells are for non-hazardous waste generated from a variety of diverse sources.
- **Municipal wastewater disposal wells**: These wells are located exclusively in Florida and are used to dispose treated municipal sewage effluent. According to the Florida Department of Environmental Protection, there are approximately 150 active municipal wastewater disposal wells in Florida. [40]
- **Radioactive waste disposal wells**: These wells inject waste that contains radioactive material. There are currently no radioactive waste disposal wells operating in the United States.

According to a 2017 well inventory, there are approximately 817 Class I wells (137 of which are hazardous) across the United States, [3] translating to less than one percent of the total active UIC well count across all well classes. Approximately 17 percent of Class I wells reported are hazardous waste disposal wells with most of those located in Texas and Louisiana. The location of active Class I wells in the United States and the respective fluid they inject (hazardous or non-hazardous) is presented in Exhibit 2-4. Data compiled from the regulating agencies with primacy for Class I wells (state or federal level) was used to generate Exhibit 2-4. Data sources are provided in Appendix C: State and Federal Agencies Tracking Underground Injection Control Class I Well Data. Due to the disparity across regulating bodies for reporting requirements, level of public data availability, accuracy, and vintage, this list is not expected to be fully inclusive of all Class I wells, but merely to provide a compilation and visual representation of well locations and types on a state-by-state basis.

Exhibit 2-4. Maps of active UIC Class I wells across the United States highlighting hazardous Class I well counts by state (top) and total Class I well count by state (bottom)



As indicated in Exhibit 2-4, most of the Class I wells are located along the Gulf Coast, near the Great Lakes, and in Florida. Based on review of the data used to generate Exhibit 2-4, it appears that most large industrial facilities use one or more Class I wells (both for hazardous and non-hazardous waste) to inject their waste onsite. However, there are also dedicated disposal facilities that serve as centralized commercial injectors, accepting waste for disposal from several difference sources. Additionally, dedicated hazardous waste management facilities are commercial facilities that receive hazardous wastes for treatment, storage, or disposal (often referred to as TSDFs). [41] EPA tracks all facilities that managed hazardous waste commercially, of which six serve as commercial deep well disposal facilities, as shown in Exhibit 2-5. [42]

Exhibit 2-5 Examples of hazardous waste management facilities utilizing Class I wells

Facility	State	EPA ID	Number of Wells*
Vickery Environmental Inc.	Ohio	OHD020273819	4
Cornerstone Chemical Company	Louisiana	LAD008175390	5
TM Deer Park Services	Texas	TXD000719518	3
Veolia ES Technical Solutions	Texas	TXD000838896	2
TM Corpus Christi Services	Texas	TXR000001016	1
Vopak Logistics Services USA Deer Park	Texas	TXD097673149	2

*Data acquired from disparate sources (i.e., overseeing regulating bodies) for Class I wells (state or Federal level) used to generate the map in Exhibit 2-4, as well as to estimate the number of wells for this column in Exhibit 2-5.

From 2019 through 2039, EPA estimates the need for 3.3 million tons per year (over 791 MMgal/yr assuming waste density of 8.34 pounds per gallon [lb/gal]) of required capacity for deep well underground injection of hazardous wastes specific for TSDFs.[a] [42] The facilities listed in Exhibit 2-5 compose the basis for projected capacity for EPA's 2014 national capacity assessment specific to commercial hazardous waste management capacity.

UIC regulation require Class I wells to have multiple concentric layers of casing and cement with continuous monitoring systems. Additionally, the injection zones must be deeper than USDWs with multiple separation layers of impermeable rock. Regardless, there are still concerns related to the disposed fluid possibly contaminating USDWs. The main risks associated with Class I wells include leaks in the injection well casing, excessive injection pressure resulting in formational and confining layer damage, the presence of improperly abandoned wells, leakage in well components such as packers and cement, and well component corrosion. To better understand these risks, their potential impacts (should they occur), and probability of happening, several studies related to Class I well risks have been published by both EPA and industry. In the mid-1980s, the Underground Injection Practices Council (UIPC) (presently known as the Ground Water Protection Council), and the U.S. General Accounting Office (GAO) (which was renamed the "Government Accountability Office" in 2004) conducted studies that described past Class I

[a] Section 104(c)(9) of the Comprehensive Environmental Response Compensation, and Liability Act, or Superfund law, requires that prior to EPA providing funding for any remedial actions, a state must assure the availability of hazardous waste treatment or disposal facilities that have adequate capacity to manage the hazardous waste expected to be generated within the state over 20 years. [42]

well malfunctions in the United States and discussed how current Class I regulations would minimize the possibility of failures. The UIPC study provided data on the operation and performance characteristics of Class I injection wells, which included case histories of Class I well sites or facilities with reported histories of operational problems. The study identified malfunctions at 26 facilities, involving 43 wells, suggesting an overall well malfunction rate of approximately 9 percent of the 500 Class I wells reported to exist at the time. Only six wells, or two percent of all Class I wells, experienced malfunctions resulting in leakage into a USDW. [43] [44]The GAO study (1987) focused on Class I failures that resulted in aquifer contamination. GAO reviewed the cause of each incident to determine whether the contamination would have happened if the 1980 UIC regulations were in place at the time. The study reported only two cases of drinking water contamination from Class I wells, one case of suspected contamination, and eight documented cases of non-drinking water aquifer contamination. For both studies, aquifer restoration efforts were conducted at the facilities where a USDW or non-drinking water aquifer was contaminated. Remedial activities associated with aquifer restoration included installation of monitoring wells, groundwater recovery systems, and excavation of contaminated soils. [28]

While there are potential risks associated with subsurface injection, Class I wells have a long history of being relatively safe. A study conducted by the EPA Office of Solid Waste and Emergency Response found that Class I wells are the safest way to dispose of liquid waste in an environmentally sound manner. [45] In another example, a 1998 study conducted by the Chemical Manufacturer's Association estimated the risk of waste containment loss for Class I hazardous injection wells and found that the probability of leakage to USDWs to be less than one in a million if the injection well meets EPA's minimum design and operating requirements. [46] The success of regulating Class I hazardous wells provides an illustrative analog for underground CO_2 storage. Specific details regarding the construction, monitoring, and operation of a Class I well (including evaluation of site geology) is provided in the subsequent sections. Section 3 further describes the specific regulations pertaining to the UIC Program, which is the regulatory body overseeing both Class I and Class VI wells; Section 4 discusses the methods and techniques used to select, characterize, and operate Class I wells based on UIC regulations.

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. For both waste injection/disposal and CO_2 injection/storage, 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. [47] Additionally, both disposal/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 I injection wells for waste disposal and Class VI injection wells for CO_2 storage. Federal regulations pertaining to Class I and VI wells and an overview of state-specific UIC Class I regulations is also 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 SDWA of 1974 establishes requirements and provisions for the UIC Program to protect public health by preventing injection wells from contaminating USDWs[b] from infiltration of brine or any injected fluid. [47] 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.

[b] 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 mg/l TDS; and (b) Which is not an exempted aquifer." [48]

Exhibit 3-1. Federal UIC-related regulations and pertaining parts within the CFR [47]

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. [2] 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. [48] 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 Waste Disposal Using UIC Class I Wells

As introduced in Section 2, Class I wells are used to inject hazardous and non-hazardous wastes into deep, confined rock formations, typically drilled thousands of feet below the lowermost USDW. Industries that commonly use Class I injection wells include petroleum refining, metal production, chemical production, commercial disposal, and municipal wastewater disposal among others. [24] [28] Injected wastes vary significantly based on the process from which they originate. Some of the most common wastes disposed via Class I wells as reported by EPA include manufacturing process wastewater, mining wastes, municipal effluent, and cooling tower and pollution control scrubber blowdown. [28] Regulations pertaining to UIC Class I wells encompass Part 144, Part 146, and Part 148 of the CFR. The relevant parts relating to the technical requirements (e.g., operations, monitoring, and financial responsibility) of UIC Class I wells include:

- 40 CFR 144 Subpart A – General Provisions (§§ 144.1 – 144.8)
- 40 CFR 144 Subpart B – General Program Requirements (§§ 144.14)
- 40 CFR 144 Subpart C – Authorization of Underground Injection by Rule (§§ 144.21, §§ 144.25 – 144.28)
- 40 CFR 144 Subpart F – Financial Responsibility: Class I Hazardous Waste Injection Wells (§§ 144.60 – 144.70)
- 40 CFR 146 Subpart A – General Provisions (§§146.1 – 146.10)
- 40 CFR 146 Subpart B – Criteria and Standards Applicable to Class I Wells (§§ 146.11 – 146.16)
- 40 CFR 146 Subpart G – Criteria and Standards Applicable to Class I Hazardous Waste Injection Wells (§§ 146.61 – 146.73)
- 40 CFR 148 Subparts A, B, and C – Hazardous Waste Injection Restrictions (§§ 148.1 – 148.24)

Class I wells are classified as hazardous or non-hazardous, depending on the characteristics of the injected waste;[c] however, wells could be further subdivided based on the specific use of each well as defined in Section 2.3. Class I non-hazardous wells currently make up approximately 83 percent (680 wells) of the total 817 active Class I wells according to EPA's 2017 inventory. [3] Class I hazardous wells currently make up approximately 17 percent (137 wells) of the total 817 active Class I wells and inject hazardous waste as defined by the RCRA. [3] Construction, permitting, operating, and monitoring requirements are more stringent for Class I hazardous waste disposal wells than for other Class I injection well categories that encompass non-hazardous wells.

RCRA is the primary law governing the disposal of solid and hazardous waste in the United States. Congress passed RCRA in October 1976 to address the increasing problems the nation

[c] Definitions for hazardous waste can be found in 40 CFR 262.

faced from the growing volume of municipal and industrial waste. RCRA is an amendment to the Solid Waste Disposal Act of 1965 and sets national goals for:

- Protecting human health and the environment from the potential hazards of waste disposal
- Conserving energy and natural resources
- Reducing the amount of waste generated
- Ensuring that wastes are managed in an environmentally-sound manner

To achieve these goals, RCRA established three distinct, yet interrelated, programs, including: 1) the solid waste program, under RCRA Subtitle D, which encourages states to develop comprehensive plans to manage non-hazardous industrial solid waste and municipal solid waste, sets criteria for municipal solid waste landfills and other solid waste disposal facilities, and prohibits the open dumping of solid waste; 2) the hazardous waste program, under RCRA Subtitle C, which establishes a system for controlling hazardous waste from the time it is generated until its ultimate disposal — in effect, from "cradle to grave"; and 3) the underground storage tank program, under RCRA Subtitle I, which regulates underground storage tanks containing hazardous substances and petroleum products. The binding provisions within RCRA have important ramifications relative to the disposal of hazardous waste via Class I wells. The following subsection provides an overview of RCRA's impact on Class I hazardous well operations.

3.1.1.1 Resource Conservation and Recovery Act Overview

Since its enactment in 1975, RCRA has been amended several times. The Hazardous and Solid Waste Amendments (HSWA), passed in 1984, were considered the most notable change to RCRA. They consist of several items including more stringent hazardous waste management standards, hazardous waste land disposal restrictions, corrective action releases, and addition of the underground storage tank program. [49] EPA amended the UIC regulations in 1988 to address the HSWA. Operators of Class I wells are exempt from the ban if they demonstrate that the hazardous constituents of the wastewater will not migrate from the disposal site for 10,000 years or will not migrate from the disposal site while the wastewater remains hazardous (which could be less than 10,000 years). This demonstration is known as a "no-migration" petition. Site-specific modeling of wastewater migration provides a foundation for a no-migration demonstration that hazardous wastewaters will remain in the injection zone for as long as they remain hazardous. A long-term analysis using simulation modeling is the only way to infer about the fate of the injected fluids. [28]

The land disposal restrictions (LDR) program was created as part of HSWA to RCRA to ensure that untreated hazardous wastes are prohibited from land disposal unless proper treatment has occurred. Hazardous wastes can occur in different forms, including solid, liquid, contained gas, or sludge, and may be generated from several types of sources. [50] Generators of hazardous waste and facilities that treat, store, or dispose of hazardous waste must ensure proper treatment/management before disposal; three options may be considered:

1. Disposal - requires waste-specific treatment standards (e.g., standard and alternative treatments and variances) to be met before a waste can be land disposed
2. Dilution - assures wastes are properly treated and not simply diluted (i.e., addition of soil or water)
3. Storage - prevents indefinite storage of untreated hazardous wastes for reasons other than the accumulation of quantities necessary for effective treatment or disposal [51] [52]

The Land Disposal Program Flexibility Act (LDFA) amended RCRA in 1996 by mandating several notable changes including those to the RCRA LDR program and the non-hazardous landfill groundwater monitoring program. The LDFA exempts from land disposal restrictions (other than requirements pertaining to applicable specific treatment methods declared by EPA under the SDWA) of solid waste identified as hazardous solely based on one or more characteristics if such waste:

1. Is treated in a treatment system that subsequently discharges to waters of the United States pursuant to a permit issued under the Federal Water Pollution Control Act (Clean Water Act), undergoes pretreatment for purposes of compliance with toxic and pretreatment effluent standards of such Act, or is treated in a zero-discharge system that EPA determines to be involving Clean Water Act-equivalent treatment
2. No longer exhibits such characteristic prior to land disposal
3. Has met any applicable specific method of treatment promulgated by EPA, including those specified in the rule proclaimed by EPA in June 1990, prior to management in a land-based unit as part of a treatment system specified in clause 1 above
4. Would not generate toxic gases, vapors, or fumes due to the presence of cyanide at the point of generation when exposed to pH conditions of a specified range [53]

Per the LDFA, Class I wells disposing of waste that does not exhibit a hazardous characteristic, including corrosivity, reactivity, ignitability, or toxicity, at disposal, [54] are exempted from the provisions of the land disposal restrictions under the RCRA LDR program. Therefore, Class I well operators would not have to identify and treat underlying hazardous constituents prior to injection if they are no longer present. [28] Regulations promulgated by EPA for RCRA are published in CFR Title 40, which pertains to the protection of the environment, parts 239-282 and are listed in Appendix D: Resource Conservation and Recovery Act Regulations.

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, discussed in a separate analog report *CO_2 Leakage During EOR Operations – Analog Studies to Geologic Storage of CO_2*. [55] 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. [56] This new Class VI well classification contains conditions 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. [6] 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. [57] 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 greenhouse gas (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. [58] 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. [59] 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. [58] 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. [59]

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 I and Class VI Wells

Hazardous and non-hazardous waste disposal using UIC Class I wells 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. This section presents a side-by-side comparison of key components within the regulations for Class I and Class VI wells. The technical operational criteria (for instance, siting and characterization, well construction, area of review [AoR], etc.) vary for either Class I 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, B, G, and H, as well as 40 CFR 144 Subpart F for well types most directly applicable to fluid disposal. 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 wastewater or CO_2) into the subsurface. [47] From a Class I perspective, the additional requirements for hazardous wells relative to non-hazardous is highlighted under the Class I column in Exhibit 3-2. Class VI requirements vary, in some regard, to Class I requirements given the relative buoyancy, mobility, and potential corrosivity of CO_2.

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

Requirement	Class I	Class VI
Siting and Characterization	▪ Confirm fluids will be injected into formation that is below the lowermost formation containing, within one-quarter mile of the well, a USDW by completing geologic studies of injection and confining zones to demonstrate: ○ Receiving formations are sufficiently permeable, porous, and thick enough to receive fluids at proposed injection rate without requiring excessive pressure ○ Formations are large enough to prevent pressure build up and injected fluid would not reach aquifer recharge areas ○ There is a low-permeability confining zone to prevent vertical fluid migration of injection fluids	▪ 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

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

Requirement	Class I	Class VI
	○ Injected fluids are compatible with well materials and rock and fluid in injection zone ○ Area is geologically stable ○ Injection zone has no economic value ▪ Complete wireline log runs and tests to inform well construction compatibility with the subsurface **Additional requirements for Hazardous Waste Wells:** ▪ Confirm fluids will be injected into formation that is below the lowermost formation containing, within one-quarter mile of the well, a USDW by completing structural studies to demonstrate: ○ Injection and confining zones are free of vertically transmissive fissures or faults ○ Low seismicity and probability of earthquakes ○ Proposed injection will not induce earthquakes	locations; determining injection zone porosity, identifying any faults, and assessing seismic history of area
Area of Review (AoR)	▪ Determine AoR by using mathematical model, such as modified Theis equation, to calculate zone of engendering influence or fixed radius of at least one-quarter mile ▪ Identify and address any improperly completed or abandoned wells through corrective action within AoR **Additional requirements for Hazardous Waste Wells:** ▪ Make radius minimum of two miles (mi) ▪ Demonstrate fluids will remain in the injection zone while they are hazardous by no-migration petition ▪ Conduct modeling to show either the waste will remain in the injection zone for 10,000 years or it will be rendered non-hazardous before migration	▪ 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 ▪ Delineate the AoR over the project lifetime (at least every five years)

Requirement	Class I	Class VI
Well Construction	▪ Require well to be cased and cemented to prevent movement of fluids into or between USDWs. The casing and cement used in the construction of new wells must be designed for the life expectancy of the well ▪ Confirm annulus between tubing and long string of casings is filled with a fluid approved by the UIC Program ▪ Inject through tubing and packer, packer set immediately above injection zone, annulus between tubing and casing filled with fluid approved by Director ▪ Ensure engineering designs are approved by regulatory agency ▪ Perform tests during drilling to ensure no vertical migration of fluid **Additional requirements for Hazardous Waste Wells:** ▪ Receive UIC Program approval of casing, cement, tubing, and packer prior to construction ▪ Verify and implement detailed requirements for tubing and packer with direction of Director ▪ Set surface string casing below lowest USDW and cement back to surface ▪ Set long string (inner) casing to injection zone and cement back to surface	▪ 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 ensure it does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs during injection ▪ Complete quarterly reporting on injection and pressures, injected fluids, and monitoring of USDWs within the AoR **Additional requirements for Hazardous Waste Wells:** ▪ Utilize automatic alarms and shutdown devices ▪ Notify permitting authority within 24 hours if problem occurs	▪ 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 **Additional requirements for Hazardous Waste Wells:** ▪ Conduct internal MIT yearly ▪ Test cement at base of well annually	▪ 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

Requirement	Class I	Class VI
		▪ Run casing inspection log to determine presence or absence of corrosion in long string casing, if required
Monitoring	▪ Monitor and record annulus pressure, containment in injection zone, and characteristics of injected fluid and watch for fluid movement into USDWs within AoR ▪ Perform continuous monitoring for pressure changes in the first aquifer overlying the confining zone, the use of indirect, geophysical techniques to determine the position of the waste front, periodic monitoring of the groundwater quality in the first aquifer overlying the injection zone, and/or periodic monitoring of the groundwater quality in the lowermost USDW if the Director requires based on site-specific assessment of the potential for fluid movement from the well or injection zone **Additional requirements for Hazardous Waste Wells:** ▪ Comply with explicit procedures for reporting and correcting problems due to lack of mechanical integrity ▪ Develop and follow a waste analysis plan ▪ Analyze wastewaters as specified in the plan	▪ 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 the CO_2 stream; pressure on the annulus between the tubing and the 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 the groundwater quality and geochemical changes above confining zone(s) or additional identified zones ▪ 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	▪ Plug well with cement, tag well, test plugs, and submit plugging and abandonment report ▪ Ensure abandoned well is in state of static equilibrium **Additional requirements for Hazardous Waste Wells:** ▪ Conduct pressure fall off and MITs ▪ Continue groundwater monitoring until injection zone pressure cannot influence USDW ▪ Flush well with non-reactive fluid ▪ Plug well by either Balance Method, Dump Bailer Method, Two-Plug Method, or other alternative approach approved by the Director ▪ Tag each plug used appropriately and test for seal and stability before closure is completed ▪ Inform authorities about the well, its location, and zone of influence	▪ Provide 60-day notice in writing before plugging ▪ Ensure compliance with approved 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

Requirement	Class I	Class VI
Proof of Containment and Post-Injection Site Care (PISC)	▪ No specific regulations in 40 CFR 146 Subpart B **Additional requirements for Hazardous Waste Wells:** ▪ Adhere to site-specific post-closure plan, which includes the pressure in the injection zone before injection began, the anticipated pressure in the injection zone at the time of closure, the predicted time until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the base of the lowermost USDW, predicted position of the waste front at closure, the status of any cleanups required, and the estimated cost of proposed post-closure care ▪ Continue to conduct any required groundwater monitoring required until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the base of the lowermost USDW	▪ 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 B **Additional requirements for Hazardous Waste Wells:** ▪ Provide notice of intent to close within 60 days prior to well closure ▪ Develop closure plan with well plugging approach ▪ Provide post-closure report 60 days after closure	▪ 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 well **Additional requirements for Hazardous Waste Wells:** ▪ Demonstrate and maintain financial responsibility that meets estimate cost of post-closure plan by using instrument(s) such as trust fund, surety bond, letter of credit, financial test, insurance, or corporate guarantee ▪ Confirm available funds are no less than the amount identified in § 146.72(a)(4)(vi)	▪ 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

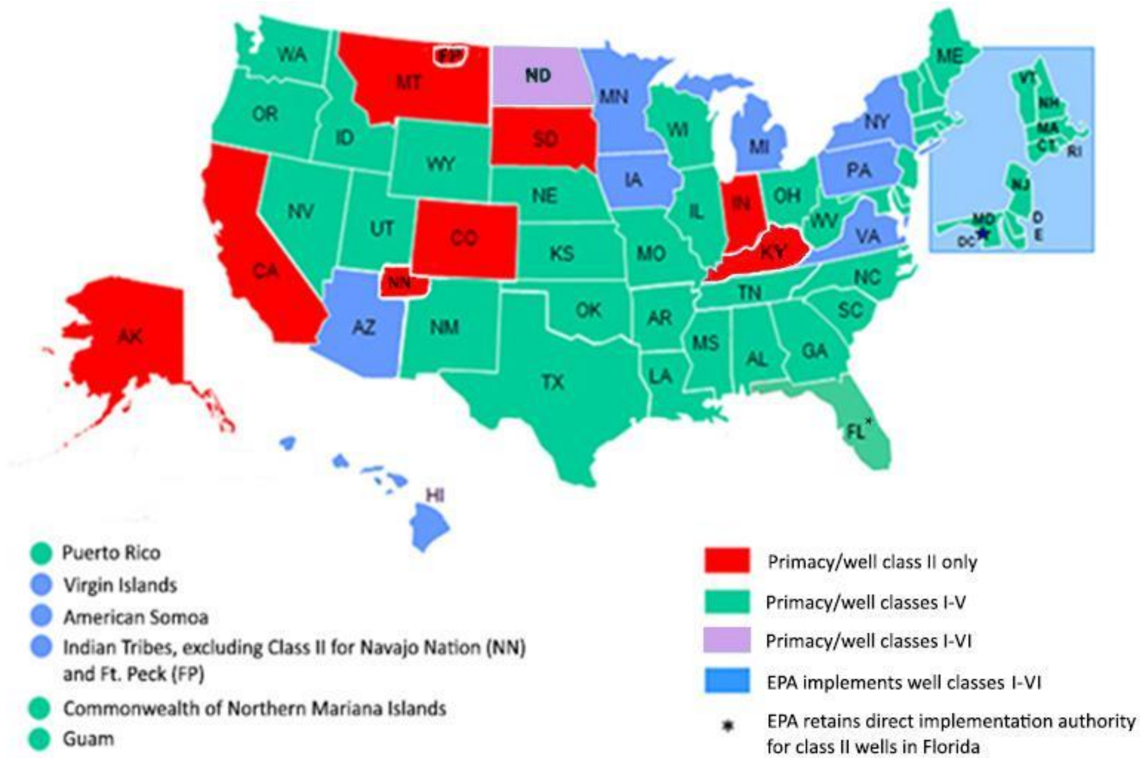
In addition to the federal requirements highlighted in Exhibit 3-2, many states have either enacted CCS requirements or are currently doing so. [56] EPA encourages state and regional governments, as well as tribes and territories, to seek primary enforcement responsibility or "primacy" for UIC well permitting, including UIC Class I and Class 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: [60]

- 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. [60] In addition, seven states and two tribes have applied for and received primacy approval for Class II wells only (Exhibit 3-3). 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 map featuring states, territories, and tribes UIC primacy status [60]



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. [60] 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. [61] The state of Wyoming has developed regulations pertaining to Class VI injection wells and applied for UIC Class VI primacy. [62] [63] 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. [60]

3.2.1 State-Specific UIC Class I 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. [56] [60] 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 six states with the most Class I injection wells are shown in Exhibit 3-4 below. [3] They have held the top six spots since at least 2010. A brief overview of the Class I regulations in each of these six states can be found in Appendix E: Overview of the Six States with the Most Class I Wells.

Exhibit 3-4. Summary of Class I injection wells in top six states for 2010 and 2017 [3] [64]

State	Class I Well Type					
	Non-hazardous		Hazardous		Totals	
	Year					
	2010	2017	2010	2017	2010	2017
Florida	211	253	1	1	212	254
Texas	50	89	58	78	108	167
Wyoming	41	73	0	0	41	73
Kansas	48	63	5	6	53	69
California	45	49	0	0	45	49
Louisiana	15	18	22	19	35	37

4 Overview of Class I Injection Well Implementation: Site Selection, Characterization, Operations, and Closure

As discussed in Section 2, the prominent storage formation type associated with waste disposal via Class I injection wells is saline-bearing aquifers. The main goal in selecting a potential Class I disposal site is to ensure isolation of the injected waste stream(s) from all overlying USDWs, mineral and fuel resources, and those portions of the environment used for most human activities. Each site is expected to have unique characteristics evaluated to determine the suitability for injection and potential impacts of injection. [31] Class I hazardous waste injection wells cannot be sited unless the injection zone has sufficient permeability, porosity, thickness, and areal extent to accommodate the volume of disposed liquid according to 40 CFR Part 146.62. These requirements are often the same as those for CO_2 storage, and the potential approaches a site operator may undertake to characterize a site for a potential Class VI well could be similar to those for a Class I well. For example, some key characteristics for CO_2 storage (as highlighted in Section 5.3) are capacity, containment, and injectivity. These characteristics are also important for subsurface waste disposal via deep well injection. The capacity of the injection well is primarily driven by the injectivity, or the amount of waste that can be injected into the subsurface through the well per day, which directly impacts the economics of the well. The containment defines the injection site’s ability to store the fluid, which must comply with various state and federal regulations. The three components depend upon geologic and hydrogeologic conditions, making only specific regions suitable for deep storage of waste. However, as noted in sections above, the siting, construction, permitting, operating, and monitoring requirements are typically more stringent for Class I hazardous waste disposal wells than for non-hazardous Class I injection wells.

There is a sequence of steps and actions for developing and implementing a Class I injection well site/project that can be broadly divided into the following major project phases presented in the bullets below. These phases were derived from the general approaches outlined in several Class I well permits and associated supplemental material. [65] The process is similar in many ways to the Class VI injection well site/project phases presented later in Section 5.4 as many of the same site screening criteria and operational safeguards are required for each well class:

- **Site selection and characterization:** Involves evaluating potential injection sites through analyses of readily accessible data and access of more detailed characterization data. The goal is to gain a detailed characterization and understanding of the subsurface to assess a potential site’s suitability for storage as a function of containment, injectivity, and capacity. Once determination of a suitable site has occurred, characterization data can be used to develop the UIC well permit and facilitate design of the injection well(s).
- **Permitting (injection):** Utilizes data from site characterization to build a Class I permit application. Once an injection permit is approved, a project will begin site preparation for eventual injection operations, including installing injection well(s).

- **Injection operations:** Begins pre-injection drilling, operational planning commences, initial corrective action activities can commence, delivery of waste to the site occurs, deep well(s) disposal operations commence, and the site monitoring is conduced to ensure safe operations.
- **Closure of injection operations and post-injection site care:** Injection operations cease and the injection well(s) will be plugged. Any associated equipment will be removed, and any site decommissioning and abandonment can occur. For Class I hazardous wells, implementation of a long-term monitoring strategy commences.

A major difference between the two practices (CO_2 storage and subsurface liquid waste disposal) is the buoyancy of the injected fluid relative to in-situ brine. Hazardous and non-hazardous waste typically ranges in density from 8.3 to 8.8 lb/gal,[e] [39] whereas supercritical CO_2 is roughly 5.34 lb/gallon,[f] which is significantly more buoyant relative to the high-salinity water typical for saline-bearing formations (8.4 lb/gallon for a 10,000 parts per million [ppm] TDS formation). [5] [66] The low-density of supercritical CO_2 provides a substantially higher risk of upward migration from the storage zone into shallower drinking water sources or to the atmosphere, [5] resulting in the need for tailored approaches to plume evaluation through site-specific monitoring and modeling strategies. A second major difference between the practices is that operators of Class I hazardous wells must demonstrate that fluids will remain in the injection zone for as long as they are hazardous. This involves modeling to show that either the waste will remain in the injection zone for 10,000 years or it will be rendered non-hazardous before migration from the injection zone. This permeance must be assured through well MITs, confirmation of confining zone integrity, and evaluation of formational pressure response from injection. [67] [68] However, regardless of the injection practice, the need to attain critical geologic parameters for project operational success remains the same regardless of operation type, which can be attained through site selection and characterization, and further understood through newly acquired operational data.

This section 1) summarizes considerations for Class I well site selection and characterization pertaining to accessing the desired capacity, retention against migration, and attaining sufficient injectivity, as well as 2) provides an overview of typical Class I well operations. Federal regulations in 40 CFR 146 and 40 CFR 148 dictate how Class I wells are implemented; however, regulations for each state with UIC Class I primacy may vary from federal regulations. These regulations have been summarized in Section 3.1.1 at the federal level. 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.

4.1 SITE SELECTION AND CHARACTERIZATION

The site selection and characterization process for determining the location for a Class I injection well requires the identification of an area where the geologic and hydrologic environment is such that the site can accept the amount of wastes planned for disposal

[e] Density ranges estimated based on reported average TDS concentrations for wastes disposed of in Class I wells in Illinois. [31]

[f] Assuming reservoir conditions of 3,100 psi and 170 °F.

throughout the life of the well and that the site can provide the long-term confinement of the waste within its injection zone and primary confining units. [31] [43] The 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 perhaps an earlier, higher-level site screening phase. [16] Site characterization tools may include both data collection (for instance, seismic surveys and well logging, core analysis, and injectivity tests) and possibly mathematical models of the selected injection and confining zone(s) (Exhibit 4-1). [69] Results from characterization efforts will elude to a site's suitability and whether it contains favorable conditions for subsurface disposal. The minimum federal siting criteria for Class I wells that owners and operators must demonstrate were outlined in Exhibit 3-2 in Section 3.1.3 above. [67] Ultimately, these requirements mandate that key characteristics including capacity, containment, and injectivity make a Class I site viable for subsurface waste disposal. Other considerations include investigating whether the site is in a geologically stable area free from earthquake activity, ensuring water-yielding units from which injection of waste is planned exceed 10,000 mg/l TDS, and reviewing existing wells penetrating the anticipated AoR to ensure man-made penetrations of the injection and subsequent confining zone(s) do not pose a leakage conduit threat.

Exhibit 4-1. EPA UIC Class I siting criteria and possible site characterization approaches

Class I Well Requirement [67]	Possible Characterization Approach
Formations are large enough to prevent pressure build-up and injected fluid would not reach aquifer recharge areas	• Well logs • Cores and core analysis • Structural mapping • Seismic surveys • Reservoir modeling and simulation
Injected fluids are compatible with well materials and with rock and fluid in injection zones	• Formational fluid sampling and analysis • Cores and core geochemical analyses • Injectate physical and chemical evaluation
Receiving formations are sufficiently permeable, porous, homogeneous, and thick enough to receive the fluids at the proposed injection rate without requiring excessive pressure	• Well logs • Cores and core analysis, including plug flow experimentation • Structural mapping • Seismic surveys • Capacity estimation calculations • Injection and well pump tests • Reservoir modeling and simulation
Injection and confining formations are free of vertically transmissive fissures or faults	• Well logs • Cores and core analysis • In situ stress testing • Seismic surveys • Structure maps • Existing data on location of faults
Area is geologically stable, has a low probability of earthquakes, and the proposed injection will not induce earthquakes or increase the frequency of naturally occurring earthquake	• Microseismic measurements • Historic seismic event records (for instance, USGS [70])
Injection zone has no economic value	• Well logs • Review of regional oil and gas production history

The following subsections describe how site characterization efforts for a Class I well would contribute towards assessing capacity, injectivity, and containment against migration.

4.1.1 Capacity

A Class I well site must provide sufficient capacity to store the amount of waste planned throughout the operational life of the well. EPA Class I requirements mandate that the receiving formations of Class I sites are sufficiently permeable, porous, homogeneous, and thick enough to receive the fluids at the proposed injection rate without requiring excessive pressure, and that formations are large enough to prevent pressure build-up and insure that injected fluid will not reach aquifer recharge areas. [67] The capacity of the storage reservoir depends on geological parameters such as thickness, fluid saturations, structural setting, stratigraphy, and lithological variations. Additional subsurface characteristics important for assessing the capacity of a reservoir include depth and pore volume, which is the product of the reservoir volume and effective porosity. [71] The areal extent of a storage reservoir is also important to the calculation of capacity, and it is influenced by boundary conditions. The reservoir boundary conditions describe the areal extent of fluid migration and pressure increase. The total capacity of a candidate storage formation will be limited by the boundary conditions, whether open or closed, to maintain safe levels of pressure increase. [28] [72]

EPA's Region V has published the formula below (Equation 4-1) to calculate the volume of fluid (i.e., capacity) to fill a portion of the subsurface with injected liquid waste. [73] This specific equation was developed to calculate the volume of waste within a potential "monitoring zone," interpreted as the radial distance between the injection well and a monitoring well. However, the equation can be adapted to provide a formational volumetric capacity estimation based on formational areal extent.

$$V = S \times \left(\phi \times (h\pi r^2)\right) \quad \textit{Equation 4-1}$$

Where:

V = volume of waste disposed (ft^3)
S = sweep efficiency (percent)
ϕ = porosity (percent)
h = formational thickness (ft)
r = distance to monitoring well (ft)

The equation is easily adapted to estimate the potential volume of waste disposed based on the areal extent of injection zone by swapping "r^2" and "π" with formational area (a) as shown in Equation 4-2:

$$V = S \times (\phi h a) \quad \textit{Equation 4-2}$$

This volumetric relationship is similar to CO_2 storage capacity estimation methodologies for saline-bearing formations published by U.S. DOE (outlined in Appendix F: Overview of the United States Department of Energy Methodology for Estimating Geologic Storage Potential for Carbon Dioxide). Furthermore, these types of volumetric equations are often used to screen and analyze capacity for a potential waste disposal project based on site characterization data acquired. The needed parameters to perform these types of capacity evaluations are described in the following subsections.

4.1.1.1 Porosity

One of the most important parameters used to determine capacity is the formation's porosity. Porosity is a measure of the formation void space. It is typically expressed as a percentage of total rock volume. In fact, porosity is defined as the pore volume divided by the bulk volume and indicates the ability of rock to store fluids. The equation for porosity is shown in Equation 4-3:

$$\phi = \frac{V_p}{V_b} \qquad \textit{Equation 4-3}$$

Where:

V_p = pore volume (volume)

V_b = bulk volume (volume)

ϕ = porosity (decimal)

Initial screening for porosity can be done through analogs of nearby fields with similar rock types and similar depositional environments. Publicly available information pertaining to well logs and formational porosity maps can be useful tools to infer formational porosity on a screening level. Porosity measurements acquired through logging or core analysis can be expensive and time consuming, but useful for site characterization purposes.

Additional time must be taken to accurately depict the formation's porosity when characterizing its geology. This can be done through well logging and core lab measurements. A distinction also must be made between the effective and total porosity within the system. The total porosity value represents all the pore spaces within a reservoir. The effective porosity value accounts for the interconnected pore space 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. A deep well disposal operator will need to quantify the effective porosity because it describes the effective pore space that will contain the waste that is injected and disposed. [74]

Real-world rock formations are typically not homogeneous, and variations in porosity can impact injection operations by making prediction of capacity, as well as fluid flow patterns challenging. Because of this, prediction of porosity and permeability in actual underground formations is difficult. While analogs can be used to screen potential site candidates, it is mandated that all Class I wells (both hazardous and non-hazardous) undergo testing to determine rock properties prior to the issue of a permit.

4.1.1.2 Thickness – Gross vs. Net Interval

The total gross thickness of the storage formation may range from tens of feet to thousands of feet but is typically 100 to 500 ft thick. This gross thickness of the disposal zone is typically identified as the distance between the lower and upper confining beds. The net thickness, or the portion of the gross reservoir thickness above a pre-determined porosity and permeability threshold, can allude to the total storage capacity of the formation. The net thickness and the horizontal dimensions of the reservoir determine the amount of fluid that can be stored and the reservoir's ability to handle the fluids without excessive pressure build-up. [31]

Common screening methods for thickness include using existing well logs and generalized cross-sections to determine an approximate thickness. Formational thickness can also be determined based on mudlogging during the stratigraphic, injection, or monitoring well drilling. Reservoir thickness is important because it makes up the interval of interest upon which the rest of the properties are based. Existing well logs can also be analyzed to infer the formation thickness, particularly gamma ray or spontaneous potential log curves. An initial screening can be performed from a single well log provided the reservoir continuity is known. However, a reading from a single log alone may result in an over-estimate (or subsequently under-estimate) of the overall reservoir thickness without support of an expanded dataset. The combination of multiple data points is critical for reducing the uncertainty in estimating reservoir thickness. Advanced characterization of the reservoir thickness will require multiple well logs (either through drilling or purchase of log data) to better understand the spatial continuity of the reservoir. The logs must also be analyzed for potential errors. In addition, the net reservoir thickness must be determined based on petrophysical cutoffs to ensure that the targeted reservoir rock meets the quantity and quality cutoff required by the operator. [75]

4.1.1.3 Formation/Reservoir Areal Extent

The areal extent of a formation/reservoir can be delineated based on extensive site characterization data acquisition and refined throughout the life of a disposal project. If the formation is part of a new development project, then new data must be acquired via seismic surveys or exploratory drilling to understand the extent. These techniques will also yield information pertaining to the formational properties, not just allude to the formation's areal extent. However, if the proposed well is to be drilled in a well characterized area (with several existing wells, logs, and other publicly available data), operators may be able to effectively determine the formational areal extent without acquiring much newly-generated data.

After the initial screening, the formation of interest can be further characterized through drilling of a stratigraphic test well if existing data is not sufficient. Drilling helps delineate the areal extent of the reservoir, but it can be extremely expensive and only provides data at one location. Seismic surveys can also help determine the aerial extent (as well as the thickness profile) of a subsurface reservoir. Cost of the seismic survey is determined by the type and extent of the seismic survey. Seismic surveys are typically performed in two-dimension (2-D) or three-dimension (3-D). 2-D seismic is gathered along a straight line along a pre-determined distance and produces a vertical cross-section of the subsurface that can be analyzed for spill point, structure, and faults. The areal extent can be determined if multiple 2-D runs are performed across the width of a formation. 3-D seismic provides a much more detailed picture and more meaningful information, but at a significantly higher cost compared to 2-D. [76] Seismic surveys can also illuminate potential subsurface drilling hazards, support the design of well trajectories, and help generate subsurface models that increase the understanding of the reservoir. [76]

The aerial extent of a subsurface reservoir is best characterized by compiling multiple types of geological data (such as well logs and seismic surveys). An example of a compilation of geologic data into a sound characterization for a Class I well can be found in the California Specialty Cheese UIC Class I non-hazardous well permit application. [77] This Class I permit application provides integration of existing data (mostly from well logs) to generate cross-sections and formational thickness maps that demonstrate formation areal extent of the intended target reservoirs. This example provides a solid basis from which a facility applying for a Class I permit could interpret the subsurface using existing data to confirm critical siting criteria for Class I wells. A summary of the California Specialty Cheese UIC Class I geologic interpretation is outlined in Appendix G: Example of Formational Areal Extent Evaluation at a Non-Hazardous Class I Well Site.

4.1.2 Injectivity

Class I wells must be able to inject waste at a sufficient rate to accommodate the volume that is generated and ultimately needs to be disposed. Injectivity is the rate at which fluids can be pumped into the injection zone. Injectivity is a direct function of formational permeability and height of the reservoir. Permeability is a measure of how interconnected the pore space of a rock is and thus how easily a fluid travels through the reservoir. It is often expressed in units of square centimeters or Darcys (D) or millidarcys (mD).[g] Injectivity tests, also called pressure fall-off tests, can be analyzed to assess permeability for an injection zone of interest. [28] The purpose of the injectivity test is to get an indication of the total permeability of the well. In this type of test, water is pumped into the well at a constant rate until pressure stabilizes; at that point, the pump ceases and the rate at which pressure decreases is measured. The pressure measurements can be graphed and permeability within the formation can be calculated. An injectivity test will provide an indication of well performance related to the desired waste disposal rate.

Calculating the injectivity index is a common approach of analyzing performance of injection wells once injection operations have started. The calculation for the injectivity index can be made from basic data, including well injection rate, injection pressure corrected for bottom hole flowing conditions, and far-field reservoir pressure. In oilfield units, the injectivity index is commonly calculated as Equation 4-4:

$$II = \frac{Q}{P_{bh} - P_e} = \frac{kh}{141.2 * \mu_w * B_w * \left(\ln\frac{r_e}{r_w} + S\right)} \qquad \textit{Equation 4-4}$$

Where:

- II = injectivity index for radial, one-dimension flow (standard barrels per day per pounds per square inch absolute [bbl/d/psia] or mD per centipoise per ft [mD/cP/ft])
- Q = well injection rate (bbl/d)
- P_{bh} = injection pressure for bottom hole flowing conditions (psia)
- P_e = far-field reservoir pressure (psia)
- k = permeability (mD)
- h = injection interval height (ft)
- μ_w = water viscosity (cP)
- B_w = water formation volume factor (reservoir volume/standard conditions volume), (dimensionless)

[g] For comparative purposes, permeability values reported for target injection zones in the Class I non-hazardous well permit application for the California Specialty Cheese facility in Manteca, CA range between 117 and 1,000 mD. [77]

r_w = wellbore radii (ft)

r_e = drainage radii (ft)

S = total near-wellbore skin (dimensionless)

In Equation 4-4, the importance of permeability (k) and injection interval thickness (h) is evident as they are the primary parameters in the numerator. The greater the thickness, permeability, or combination of both, in the injection interval (i.e., net thickness) will directly improve overall well injectivity relative to the other parameters, which are strongly influenced by either geology or the physical properties of the injected fluid. Total near-wellbore skin effects (resistance to flow from the well into the reservoir) may be caused by mechanical (completion) skin, formation plugging, fracturing (causing a negative skin), and flow-related skin (turbulence). [78]

Well stimulation in which the injection zone is subjected to controlled fracturing is allowed by regulation because of its capacity in some geologic settings to increase injectivity and can be used to elevate possible wellbore skin issues. Fracture treatments produce fractures of limited extent with permanent apertures (and increase formational permeability) that remain transmissive when the pressure that formed them is relieved. In this situation, fracturing is not an environmental concern, whereas uncontrolled fracturing caused by excessive waste injection pressures is of greater concern. [79] As an example, in 1976, a disposal well injecting waste from the non-hazardous natural gas scrubbing operation in Illinois within the Mount Simon formation of the Illinois Basin had been hydro-fractured to increase injectivity because of its low permeability. However, the site operator was requested to demonstrate that the integrity of the Eau Claire confining zone had not been affected as a result. [31]

4.1.3 Containment

A Class I injection site's most important characteristic is its ability to contain the injected fluids and prevent migration into USDWs. Whether a hazardous or non-hazardous injection well, both must meet regulatory requirements pertaining to the site's ability to prevent subsurface migration of the injectate (or native fluids like brine) out of the injection zone. The injection site must have a confining layer (ideally several) consisting of low permeability, laterally continuous subsurface layers that restricts flow into over-lying strata. Shale and limestone lithologies are often considered favorable confining layers. [43] Operations are safer when there are more lower permeability strata between the injection zone and USDWs because it reduces the likelihood of injected fluid migration into the USDW. UIC regulations require that the confining zone(s) must be laterally continuous and free of transecting, transmissive faults or fractures that cover an area sufficient to prevent movement of fluids and contain at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing vertical propagation of fractures. [67]

An additional consideration related to containment is that Class I site areas must be geologically stable and not subject to frequent or destructive geologic events that could result in the migration of hazardous fluids. [67] Specifically, 40 CFR 146.62 (for hazardous waste wells) requires that an operator must conduct an analysis on the seismicity of the region and an analysis of the local geology and hydrogeology. Any seismicity in a region may generate subsurface faults, which may allow fluids to migrate through the confining zone(s). Therefore, geologic stability in the region ensures that the injection zone and any over-lying confining zones will not be damaged and lead to leakage.

In addition to subsurface requirements, there are regulatory requirements that govern the containment of fluid. These regulatory requirements include a 10,000 year no-migration rule (specific to hazardous wastes) and strict well construction guidelines. Class I wells are sited so that if any of the components fail, the injected fluids will remain confined to the injection zone. [28] These topics are addressed in subsections below.

4.1.4 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 the case of an area permit, the project area plus a circumscribing area the width of which is either one-quarter of a mile or a number calculated according to the criteria set forth in 40 CFR 146.06. For hazardous waste wells, the AoR for Class I hazardous waste injection wells is a two-mile radius around the wellbore per 40 CFR 146.63. Essentially, an injection site area is represented by a circle with an exterior radius, or the lateral extent, which is the area around the wellbore that represents the impact of injection expected to create an upward hydraulic gradient that could impact a USDW. The AoR provides the operator with a defined 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. Those that could cause movement of fluids into USDWs if not properly plugged and abandoned will require corrective action (described below under Section 4.2).

EPA solicits input from the owners or operators of injection wells to best identify which method (i.e., fixed radius or calculated approach) is most appropriate for each geographic area or field. The AoR is a parameter that can be calculated by using multiple accepted methods or combination of methods including: [31] [77]

Equation 4-5 is a volumetric assessment that compares the injection amounts with porosity and storage volume. However, it assumes that the injected fluid will uniformly fill a cylinder expanding away from the injection well under horizontal flow and under reasonable dispersion. The approach in Equation 4-5 estimates the fluid front radius only and does not consider the pressure buildup; therefore, it serves more as an estimate of the minimum requirements for storage volume in the injection zone and the possible movement of the injected fluid opposed to an approach to evaluate AoR: [77]

$$R = \sqrt{\frac{V}{23.4 h \phi}}$$ *Equation 4-5*

Where:

R = radius of invaded zone from the well (ft)

V = volume injected (gallons)

h = height (thickness) of the injection zone (ft)

ϕ = porosity of the aquifer (percent)

When correcting for dispersion with a dispersion coefficient to account for molecular diffusion processes, as well as mechanical dispersion processes, [80] Equation 4-6 can be used: [77]

$$R' = R + (2.3 \times (D \times R)^{\frac{1}{2}}) \qquad \textit{Equation 4-6}$$

Where:

R' = radius of invaded zone with dispersion (ft)

R = radius of invaded zone from the well (ft) calculated from Equation 4-5

D = dispersion coefficient (ft)

Equation 4-7 provides a modified Theis well pumping equation method that predicts the change in potentiometric head of an aquifer. This approach is offered under 40 CFR 146.6 as a way to computationally estimate AoR using a zone of endangering influence (ZEI) and must be calculated for an injection time period equal to the expected life of the injection well or pattern. The ZEI is defined as the radial distance in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into a USDW. If field data results in a ZEI larger than a fixed radius AoR, and there are wells within the expanded ZEI area that penetrate the proposed zones of injection, a corrective action plan modification may be required by EPA as part of Class I operations: [81]

$$r = \sqrt{\frac{2.25Kht}{S10^X}} \qquad \textit{Equation 4-7}$$

Where:

r = zone of endangering influence (ZEI) from injection well (length)

K = hydraulic conductivity of the injection zone (length/time)

h = thickness of the injection zone (length)

t = duration of injection, project life (time)

S = storage coefficient (dimensionless)

X = defined in Equation 4-8 (dimensionless)

$$X = \frac{4\pi Kh * \left(h_w - h_{bo} * S_pG_b\right)}{2.3\text{Q}} \qquad \textit{Equation 4-8}$$

Where:

Q = injection rate (volume/time)

h_w = hydrostatic head of USDW (length) measured from the base of the lowest USDW

h_{bo} = observed original hydrostatic head of injection zone (length) measured from the base of the lowest USDW

S_pG_b = specific gravity of fluid in the injection zone (dimensionless)

The modified Theis equation inherently assumes the following as per 40 CFR 146.6:

- Injection zone is homogenous and isotropic
- Injection zone has an infinite area extent
- The injection well penetrates the entire thickness of the injection zone
- Injection well diameter is infinitesimal compared to the ZEI (r) when injection time is longer than a few minutes
- The emplacement of fluid into the injection zone creates instantaneous increase in pressure

The pressure wave calculation equation provided by Warner and Lehr (1981) (Equation 4-9) can be used to estimate the reservoir pressure resulting from injection at specific times and distances from the injection well. [82] The equation assumes that the system has reached steady state from injection: [77]

$$P_{(r,t)} = P_i + \left(\frac{162.6Q\mu}{kh}\right)\left(logt + \ log\left(\frac{k}{\phi\mu c r^2}\right)\right) - 3.23 + \ 0.87s \qquad \textit{Equation 4-9}$$

Where:

$P_{(r,t)}$	= pressure as function of distance from the injection well and time since injection began (pounds per square inch [psi])
P_i	= initial reservoir pressure (psi)
Q	= flow rate (bbl/d)
μ	= viscosity of injectate (cP)
k	= permeability (mD)
h	= reservoir thickness (ft)
t	= time (hours)
ϕ	= porosity (percent)
c	= compressibility (per volume/volume/psi)
r	= radial distance (ft)
s	= well efficiency (percent)

Solving for Equation 4-9 above at various distances (r) from the injection well provides an estimate of the increase in pressure due to injection at time-intervals of interest.

When Congress enacted the HSWA to RCRA in 1984, it authorized a ban on the land disposal of hazardous waste, unless the hazardous waste is treated to meet specific standards. EPA amended the UIC regulations in 1988 to address the HSWA. Operators of Class I wells are exempt from the ban if they demonstrate that the hazardous constituents of the wastewater will not migrate from the disposal site for 10,000 years or for as long as the wastewater remains hazardous. This demonstration is known as a no-migration petition. Site-specific modeling of wastewater migration provides a foundation for a no-migration demonstration that hazardous wastewaters will remain in the injection zone for as long as they remain hazardous. The conditions at the final time step (10,000 years) are the objective, but it is possible to show the physical position of injected fluids at any specified time via simulation models. Models are also the basis on which the requirements for hazardous and non-hazardous waste disposal were developed. A long-term analysis is the only way to know with absolute certainty what will happen to injected fluids; however, this is impractical, given the time frames involved in movement of deep-injected fluids. [28]

Models used for this demonstration can be constructed based on field observations and measurements of downhole pressure, surface injection pressure, geophysical logs, rock cores extracted from depth, injectivity tests, pressure fall-off tests, tracer surveys, injection chemical concentration, and fluid density. Specifically, when applicable, operators are expected to provide their own no-migration modeling strategy driven by the site geologic properties. EPA's Region 6 published guidance for operators developing modeling strategies for no-migration petitions. [83] Over time, the results of modeling can be verified against actual data from the field (e.g., data from pressure tests, drawdown or build-up tests, and fluid monitoring).

4.1.5 Well Construction Guidelines and Considerations

The primary objective in the construction of a Class I injection well is the protection of groundwater by assuring containment of the injected wastes through a multilayer protection system. [43] However, construction design between hazardous and non-hazardous wells can vary based on UIC regulations. Exhibit 2-1 in Section 2 provides a general schematic of an open hole injection well featuring key well components as a reference for the following text. One of the first stages of either type of Class I well construction is to drill a wellbore below the lowermost USDW; a steel casing (surface casing) is then installed that runs the entire length and is cemented, possibly back to the surface. For Class I hazardous wells, the surface casing must be cemented back to the surface. The second stage is to continue to drill below the surface casing to the injection zone. A second smaller diameter steel casing (injection casing or long string casing) is installed from the surface down to the injection zone and can be cemented to an interval above the injection zone to prevent migration of fluids into an overlying USDW. For Class I hazardous wells, this long string casing is fully cemented to the surface. An injection packer (a plug with a hole in the middle) is installed in the injection casing above the injection zone, and a 2.5 – 7-inch diameter pipe (injection tube) is placed through the center of the packer. The packer is inflated to form a seal between the injection casing and the injection tubing. The area between the injection casing and injection tubing, also known as the tubing annulus, is filled with a corrosion inhibiting fluid. The pressure of the fluid in the annulus can be monitored for any changes in the system that may indicate leakage. [43] Based on this approach, the specific casing and cementing plan 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, and axial loading, hole size, size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material), the corrosiveness of injected fluid, formation fluids and temperatures, and specific lithology of injection and confining intervals, as well as the type or grade of cement. Worth mentioning is that typical onshore well construction includes installation of a conductor casing (featured in Exhibit 2-1) prior to drilling and running the other casing strings. The conductor casing is set in the shallow section of most wells drilled in unconsolidated sediment or soil near the surface in order to prevent those sediments from washing out or caving in. [84]

EPA regulates the construction of Class I wells, as summarized in Exhibit 3-2 in Section 3.1.3. The specific federal construction requirements for Class I non-hazardous wastes are detailed in 40 CFR 146.12, while construction requirements for Class I hazardous wells are in 40 CFR 146.65 and 40 CFR 146.66. For Class I non-hazardous waste injection wells, 40 CFR 146.12 specifies the following, regarding design and construction:

- Well must be cased and cemented to prevent fluid movement into or between USDWs
- Injection tubing has a packer or fluid seal
- Except for municipal wells injecting non-corrosive wastes, all Class I wells shall inject fluids through tubing with a packer set immediately above the injection zone
- Well logs and other well tests are required during the drilling and construction of new Class I wells
- Properties of the injection formation need to be measured or calculated, including fluid pressure, temperature, fracture pressure, and physical/chemical properties of the injection matrix and formation fluid

For Class I hazardous waste injection wells, 40 CFR 146.65 specifies that the design and construction:

- Must permit the use of testing devices and workover tools
- Will permit the continuous monitoring of injection tubing and long string casing
- Will ensure that all materials used in construction are compatible with any fluids encountered
- Will ensure that any cement and casing will have the life expectancy of the well and the casing and cementing program will prevent migration of fluids into or between USDWs and potential leaks of fluids from well
- Will extend one surface casing beneath the lowest USDW and cement this casing back to the surface by circulating cement from base of casing to the surface
- Will have at least one long string casing extending from the surface into the injection zone that is cemented by circulating cement to the surface
- Has a packer or fluid seal

These design areas must be described in detail during the permit application process, which is reviewed and approved by the permitting authority (federal or state depending on primacy for Class I wells). The regulations provide a maximum permit term of ten years, but renewal of permits for an additional ten years is allowed.

4.2 PERMITTING (INJECTION)

Permitting requirements for UIC Class I wells may vary from federal requirements for State's with Class I primacy. In general, for UIC Class I wells, the site operator must submit a UIC Class I permit (either hazardous or non-hazardous depending on the well type) application to the applicable regulatory agency for authorization to install and operate the well. Permit applications are built on data and information attained during project planning and site characterization phases and must account for site-specific geology. The following bullets provide a high-level overview of the major considerations operators may likely address as part of the UIC Class I permitting process.

- Injection well(s) construction design, including plans for well testing and drilling. Except as authorized through an area permit[h], no well construction may start until a permit has been issued containing construction requirements.
- The planned maximum injection volumes and/or pressures expected during operations. The operator must assure that injection operations do not result in flow rates or pressures that initiate fractures in the confining zone, and that injected fluids or formational fluids do not migrate into any USDWs.
- Identification of the types of tests and methods used to generate the monitoring data as part of operations.
- Plans and procedures expected to plug and abandon the well(s).
- Demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation.

Following a thorough technical review of the permit application, EPA (or another agency holding State primacy) may determine that the information provided was sufficient to complete a draft UIC permit given that the content within the application is deemed protective of USDWs as required under the SDWA. Alternatively, more information may be requested in areas deem deficient. Draft permits provide for public comment as a way to support early engagement from overburdened communities (those minority, low-income, tribal, or indigenous U.S. populations/geographic locations that potentially experience disproportionate environmental harms and risks [85]) and enable a mechanism for those communities to provide input to the permitting process. [65] This process may be typical for most UIC-related injection well permits. Feedback received from the public comment period may influence the final Class I permit. Class I permits are effective for a fixed term but are not to exceed 10 years per 40 CFR 146.36.

Once the final permit is issued, the operator can proceed with constructing the Class I well(s). Additionally, once a project's AoR is determined and a permit has been issued for the Class I well(s), corrective action activities can be performed where movement of fluids into USDWs may occur if existing wellbores are not properly plugged and abandoned. Corrective action may include (but is not necessary limited to) reentering, plugging, and abandoning any production or

[h] Class I non-hazardous wells can be permitted under area permits (permits issued on an area basis, rather than for each well individually). Per 40 CFR 144.33, Class I hazardous waste wells, as well as Class VI wells for CO_2 storage, are exempt from area permits.

exploratory wells which penetrate the injection zone and are located within the permit's AoR to ensure there are no leakage conduits associated with existing penetrations.

4.3 Injection Operations

The operations phase is the project phase in which active waste transportation and injection occurs at the selected disposal site. The preliminary activities of this phase include operational planning, site preparation, pre-injection drilling (including injection wells and any new monitoring wells), well and facility construction, and injection planning. The operation of non-hazardous Class I wells is governed by 40 CFR 146.13 while 40 CFR 146.67 and 40 CFR 146.68 govern hazardous Class I well operation. Both regulations specify that injection pressure is a key well operating parameter to ensure that the injection pressure in the injection zone does not initiate new fractures or propagate existing fractures, does not initiate fractures in the confining zone, and does not cause the movement of injection or formation fluids into a USDW. As mentioned in the sections above, the injectivity of a well relies on the formation's permeability and thickness, as well as injection pressure (Section 4.1.2). Injection pressure is the pressure required to overcome in situ formation water displacement, which enables the waste to permeate into the rock matrix. However, formations with low permeability or thin thickness will have limited injectivity, requiring higher injection pressures or additional injection wells to inject the desired volume of waste. The operating conditions for Class I wells are essentially limited to ensure that the pressure at which the fluids will be pumped into the subsurface is safe, that the rock units can safely receive the volume of fluids to be disposed of, and injection will occur at pressures that will not initiate new fractures or propagate existing fractures. [67] Therefore, it is critical that sites are screened and characterized to ensure safe injection can occur at the desired rate and the desired volume of waste to be disposed, and that well design is able to accommodate the waste stream while ensuring protection of USDWs.

In addition to limiting injection pressures, 40 CFR 146.13 requires that non-hazardous Class I wells:

- Never inject between the outermost casing and the wellbore
- Install and use continuous recording devices with alarms for injection pressure, flow rate, volume, and annulus pressure
- Demonstrate and report the mechanical integrity at least once every five years
- Measure and report the physical characteristics of the injection fluids
- Monitor and report on impact to other wells in the AoR

In addition to limiting injection pressures, 40 CFR 146.67 and 40 CFR 146.68 requires that hazardous Class I wells:

- Never inject between the outermost casing and the wellbore
- Maintain the annulus pressure at a higher level than the injection pressure
- Insure conditions limiting temperature and pH are maintained for any wastes that may generate reaction gases

- Develop procedures to ensure pressure imbalances do not occur
- Install and use continuous recording devices with alarms for injection pressure, flow rate, volume, fluid temperature, and annulus pressure
- Install automatic shut-off systems
- Develop and implement a waste sampling and analysis plan (see Section 4.3.1)
- Complete a hydrogeologic compatibility determination to ensure waste does not adversely impact the geologic storage formation
- Conduct periodic MIT
- Continuously monitor corrosion impact on construction materials if required

The following subsections provide more detail to a few specific aspects associated with operation of UIC Class I wells.

4.3.1 Class I Injection Well Waste Analysis

40 CFR 146.13(b)(1) requires any operator of a Class I underground injection well to monitor and analyze the fluids injected into the well "with sufficient frequency to yield representative data of their characteristics." In addition, 40 CFR 146.68(a) specifies that owners or operators of Class I wells injecting hazardous waste "shall develop and follow an approved written waste analysis plan (WAP) that describes the procedures to be carried out to obtain a detailed chemical and physical analysis of a representative sample of the waste, including the quality assurance procedures used." 40 CFR 146.68(a) further specifies that "at a minimum, the plan shall specify: (i) the parameters for which the waste will be analyzed and the rationale for the selection of these parameters; (ii) the test methods that will be used to test for these parameters; and (iii) the sampling method that will be used to obtain a representative sample of the waste to be analyzed." A few examples of the importance of following a WAP are described here for illustrative purposes:

1. Compatibility of waste with the injection and confining zone lithologies and the well materials is virtually indeterminant unless the injected fluid has been satisfactorily described.
2. The interpretation of data gathered through deep groundwater monitoring near a Class I injection well is heavily influenced by prior knowledge of what waste has entered the injection zone.
3. Regulatory changes may require either the cessation of injection of certain wastes or the restriction of certain constituent concentrations in the waste.
4. A WAP at commercial facilities and facilities with multiple waste streams is particularly important when batches of waste from varying sources need to be characterized and where composited wastes change in character with time.
5. Facilities that operate under certain chemical or other waste property limitations must be able to assure Region 5 that these limitations are not being exceeded.

EPA's Region V has developed guidance for Class I injection well facilities in preparation of a waste analysis plan. [86] The document provides guidance for waste analysis testing procedures, including the types of parameters to evaluate and frequency of sampling (differentiating procedures for hazardous waste characterization from non-hazardous wastes), as well as quality assurance during waste analysis (related to chain-of-custody, equipment and trip blanks, equipment calibration, and data validation).[i]

4.3.2 Monitoring

Class I injection wells are continuously monitored and controlled. Requirements include monitoring, reporting, and record keeping. Class I wells are affixed with continuous recording devices to monitor injection pressure, flow rate and volume, and the pressure on the annulus between the tubing and the long string of casing. As a result, large data sets are generated, which allude to the safety of the injection, provide indication of any possible leaks occurring, or notify operators if operational parameters (like injection pressure) are out of permitted bounds. Alarms may be connected to trigger when operational parameters are outside of expected ranges. [43]

40 CFR 146.13 governs the monitoring of non-hazardous Class I wells while 40 CFR 146.68 governs hazardous Class I well operation. Both regulations require wells to be equipped with continuous monitoring equipment and mandate periodic test of mechanical integrity. However, additional monitoring is required in the subsurface to track the pressure build-up in the injection zone.

For non-hazardous Class I wells, 40 CFR 146.13 requires that the following monitoring must occur in addition to continuous recording devices within the injection well:

- Analysis of the injected fluids with sufficient frequency to yield representative data of their characteristics
- Use of monitoring wells within the AoR to evaluate for migration of fluids or pressure build-up in USDWs
- Demonstration of mechanical integrity pursuant to 40 CFR 146.8 at least once every five years during the life of the well

For hazardous Class I wells, 40 CFR 146.68 requires that the following monitoring occurs in addition to continuous recording devices within the injection well:

- Monitoring of the injected wastes per approved written waste analysis plan (Section 4.3.1)
- Possible corrosion monitoring of well construction materials
- Internal MIT annually pursuant to 40 CFR 146.8
- Evaluation of cement at the base of the well annually

[i] This document can be found at: https://www.epa.gov/sites/production/files/2015-09/documents/r5-deepwell-guidance8-preparing-waste-analysis-plan-class2-19940121-8pp.pdf.

- Use of monitoring wells within the AoR to evaluate for migration of fluids or pressure build-up in USDWs

Additional ambient monitoring for both Class I well types may also include:

- Use of indirect geophysical techniques to determine the position of the waste wave front
- Periodic monitoring of groundwater quality

4.4 CLOSURE OF INJECTION OPERATIONS AND POST-INJECTION SITE CARE

Site closure and post injection site care (PISC) activities take place once all injection operations have ceased. Federal requirements pertaining to Class I injection well closure and PISC mostly relate to hazardous wells under 40 CFR 146.71 and 146.72. Site closure activities include decommissioning surface equipment (associated with injection), plugging injection wells, restoring the site, and preparing and submitting site closure reports. For Class I hazardous injection wells, MITs are required prior to injection well closure, as well as flushing the well with fluid. A pressure decay analyses in the injection zone must also be conducted prior to Class I hazardous injection well closure. Specific closure requirements are not explicitly specified for Class I non-hazardous wells under 40 CFR 146 Subpart B. [67]

The PISC phase for Class I hazardous injection wells generally includes: 1) assurance of financial responsibility (discussed in Section 4.4.1), which can cover the costs of closure and PISC requirements; and 2) conducting any groundwater monitoring required per the permit until pressure in the injection zone decays to the point that the well's cone of influence[j] can no longer influence the base of the lowermost USDW.

4.4.1 Financial Responsibility

Class I hazardous well owners and operators must demonstrate and maintain financial responsibility for plugging and abandoning all existing and new Class I hazardous injection wells in accordance with 40 CFR 144.63. Financial instruments that can be used to meet this requirement include trust fund, surety bond, letter of credit, insurance, financial test/corporate guarantee, or a combination of these mechanisms. These financial instruments have to provide sufficient funds to plug and abandon wells consistent with approved closure plans. Financial responsibility is also required for post-closure by using a trust fund, surety bond, letter of credit, financial test, insurance, or corporate guarantee that covers closure and PISC per 40 CFR 146.73. The amount of the funds available must be equal to or more than the cost to complete those actions required for closure and PISC depending on the specific site. Ultimately, financial responsibility requirements protect USDWs from endangerment, as well as the public from bearing well abandonment costs if a well owner defaults on the permit requirements. [87]

[j] Per 40 CFR 146, the cone of influence is described as the area around the well in which increased injection zone pressures caused by injection into the hazardous waste injection well would be sufficient to drive fluids into a USDW.

4.5 COST OF SUBSURFACE WASTE DISPOSAL

The reason unground disposal of hazardous and non-hazardous waste is such a popular waste management approach is that it is still the lowest cost disposal option relative to other treatment options. The factors impacting cost include the depth of the injection zone, rate of injection, formation injectivity, drilling costs, well operating costs, and the need for any treatment (filtration) prior to injection. The total cost of a deep well waste injection system is therefore dependent upon its specific location and may vary greatly from the cost at other sites (for instance, more favorable geologic conditions and shallower injection intervals could result in lower costs relative to deeper, less geologically favorable sites). There is limited documentation available with detailed cost data associated with deep well disposal. Additionally, most sources that do provide such data are typically antiquated. However, a few studies provided a high-level assessment of costs associated with various types of deep well disposal that are worth summarizing to provide context for associated Class I waste disposal costs.

The U.S. EPA (1980) estimated capital cost as high as $1,000,000 to $1,340,000 for a deep disposal injection well based on the Engineering News Record Construction Cost Index of 3119, but did not specify an injection rate, pressure, or well depth from which costs for different systems could be developed. [88] The Illinois State Geologic Survey (1989) [31] expanded on these EPA-reported capital cost values by estimating annual operating costs based on operational parameters specific to wells in Illinois. In their analysis, the total capital investment costs were first estimated for injection systems of 0.1- MMgal/d and 1.0-MMgal/d assuming an injection pressure of 300 psi. Capital costs estimates were reported as $693,000 and $783,000 respectively. The corresponding direct operating costs for these systems are $144,000 and $261,000 per year (excluding tax assessment for injection well disposal, which in 1985 ranged from $2,000 to $9,000 per year, depending on the volume of waste injected). Total annual costs for the 0.1-MMgal/d and 1.0-MMgal/d systems were reported as $293,000 and $485,000, respectively. The deep well injection costs presented above were calculated by the Illinois State Geological Survey from U.S. Department of Interior cost data based on an Engineering News Record Construction Cost Index of 1285. [89] However, actual cost figures from wells within Illinois were reported as ranging from one and a half to two times higher than the values estimated using the Illinois State Geologic Survey's approach. [31]

In a 2006 study, the UIC Program's National Technical Workgroup (NTW) [39] evaluated potential technical issues and developed recommendations regarding the use of injection wells for the disposal of drinking water residuals (DWTR). Ultimately, the recommendations made were intended for use by the UIC program in efforts to develop an Agency position on DWTR disposal via deep well injection. Since DWTR were deemed similar to those injected in Class I, Class II, and Class V wells and would require similar well construction and operational requirements, some states with UIC primacy (like Texas) offer operators the option to inject DWTR in their well class of choice. [90] Regardless, the NTW estimated that the cost of constructing a DWTR injection well (non-hazardous well), could vary from $500,000 to $1.25 million depending on the specific drilling and construction requirements (assumes a depth range between 1,800 to 5,710 ft). Most the costs associated with an injection well are attributed to the completion phase, with logging, operating, and reporting making up a small portion of the total cost. This cost estimate does not consider the costs to maintain and operate the well after installation which, per EPA's suggestion, can range from $10,000 to $20,000 annually depending on the testing requirements and their frequency. It is important to note that the typical life expectancy of a properly operated and maintained well is about 40 to 50 years. [39]

As discussed above, operators of Class I hazardous waste injection wells must demonstrate that the waste will not migrate from the disposal site for 10,000 years or not until it is no longer hazardous. This no-migration demonstration requires the preparation of a no-migration petition, which is a lengthy process that requires up to thousands of hours of technical work by a workforce consisting of engineers, computer modelers, geochemists, geologists, and other scientists, and may cost over $300,000 according to EPA. Factoring in the cost of necessary geological testing and modeling, no-migration petitions can cost more than $2 million. [28]

It's worth noting that most of these estimates are fairly dated and vary from study to study but do provide perspective into the potential cost implications associated with deep well injection. However, a more recent (albeit undated) cost estimate by Chesapeake Energy for salt water disposal (using Class II wells) has reported costs that range between less than $0.25/bbl to upwards of $2.50/bbl as a cost for centralized commercial facilities. [91] To compare the cost of subsurface liquid waste disposal, U.S. DOE has conducted a study that evaluated CO_2 storage costs in saline bearing formations in four different basins (Illinois Basin, East Texas Basin, Powder River Basin, and Williston Basin) within the United States. This study reported CO_2 storage costs (not including capture or transport) to range between $5.75 to $17.86 per metric ton (in 2011 dollars [2011$]). These costs were estimated assuming a CO_2 injection rate of 3.2 million tonnes per year (Mt/yr) over a 30-year operational timeframe (further described in Section 5.5). [92]

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). [6] 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 waste disposal practices using Class I hazardous and non-hazardous 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 liquid waste disposal 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. [5] 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.[k] [93] 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. [5] The storage of CO_2 in geologic formations shares many comparable features to oil and gas accumulations in hydrocarbon reservoirs and methane 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. [23] 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), [94] fully-integrated CCS systems are still considered costly and not entirely matured. [95] [96] 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

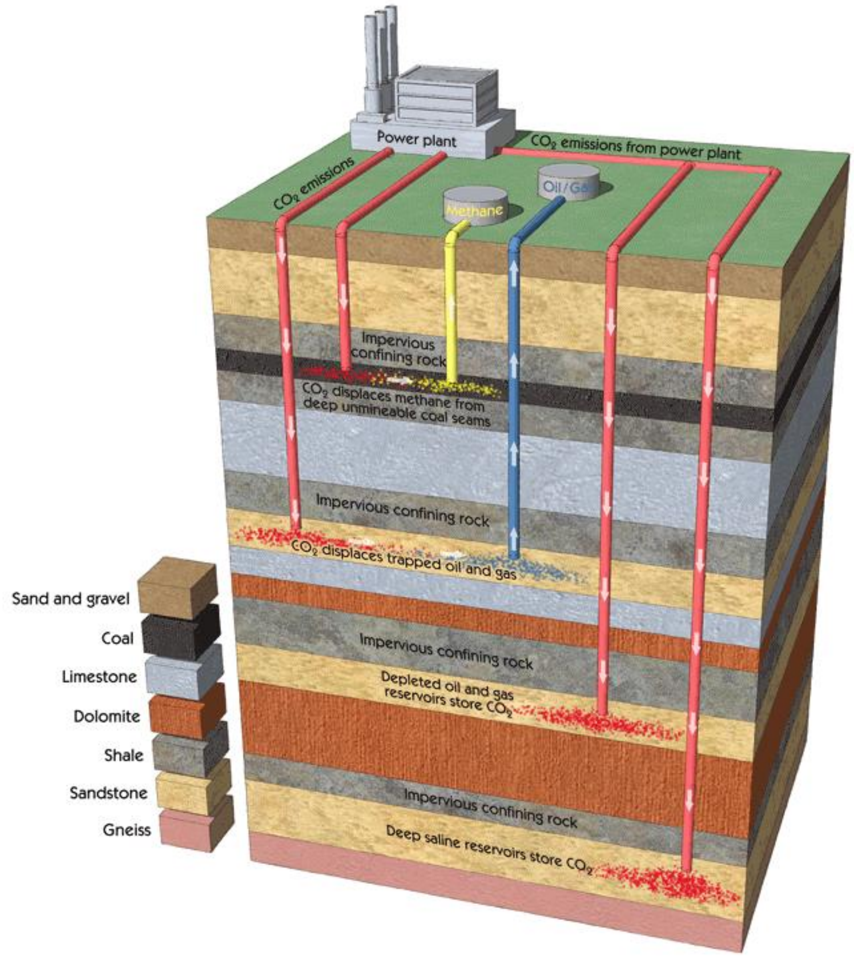
[k] The 2DS as described by IEA is based on technology implementation across all energy sectors that would achieve an 80 percent chance of limiting average global temperature increase to 2 degrees Celsius (°C) by the 2050 timeframe. [179]

used to inform regulators and industry on the safety and permanence of CCS and help toward facilitating widespread commercial deployment. [18]

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; also a widely used formation type for liquid waste disposal using Class I wells. 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. [16] [97]

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. [5]

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 [98]

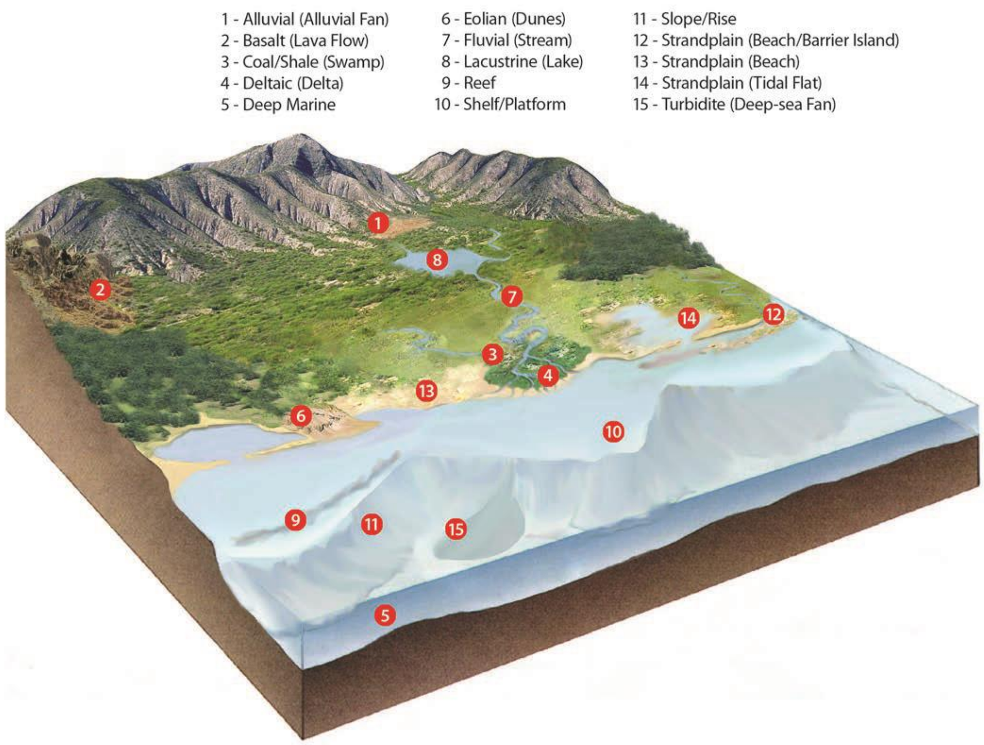


Source: Ohio Department of Natural Resources

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). [5] 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. [15] 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. [99]

Exhibit 5-2. Schematic of possible depositional environments [97]



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. [15] 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. [18] 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. [5] In contrast to waste disposal under Class I wells where waste is injected and disposed in the liquid phase with densities similar to the native subsurface fluids, CO_2 is often stored as the preferred supercritical state (and more buoyant than native subsurface fluids).

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). [100] 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. [101] [102]

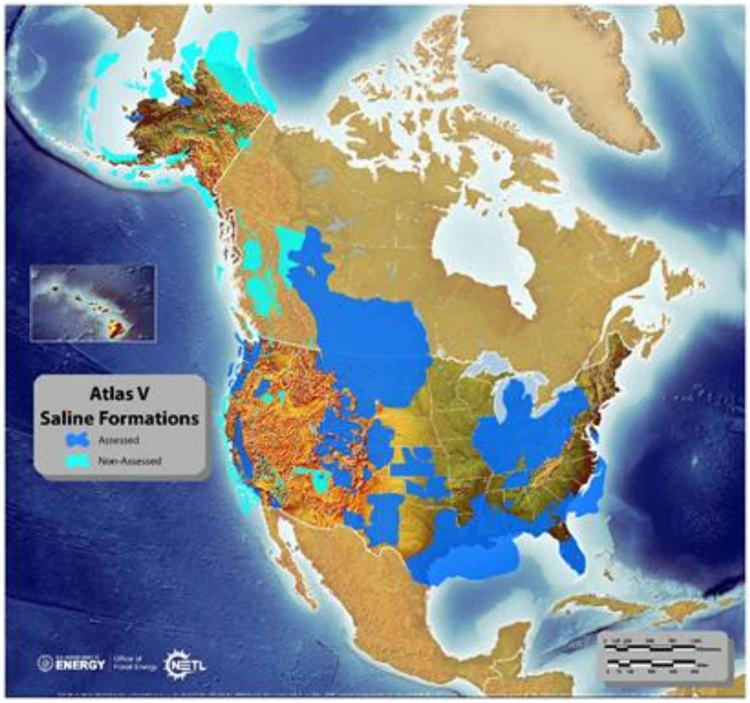
5.2.1 Saline Formations

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. [5] 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).[l] [15] 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 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. [6] 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.

[l] CO_2 resource assessments included in Section 5.2.1are calculated from low (P_{10}) and high (P_{90}) efficiency factors. [15] 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 [15]



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). [5] [7]

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. [7] [16] [100] 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: [103]

- 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). [104] [105] 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/d/Pascal/meter or bbl/d/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. [106]
- **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, 3-D seismic surveys may be combined with existing well data to estimate the formation porosity. [107] [108] A second key parameter in estimating capacity is the CO_2 utilization factor, or the effective pore volume. [71] [99] 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. [99] 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. [106]

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. [71] 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. [109] 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. [110] 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). [110] 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 probabilistic analysis capability; [111] [112] 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. [106]

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 hazardous and non-hazardous deep well waste disposal design and operations, which include 1) capacity, 2) injectivity, and 3) containment. Appendix H: 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. [103] 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 deep well injection, 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)

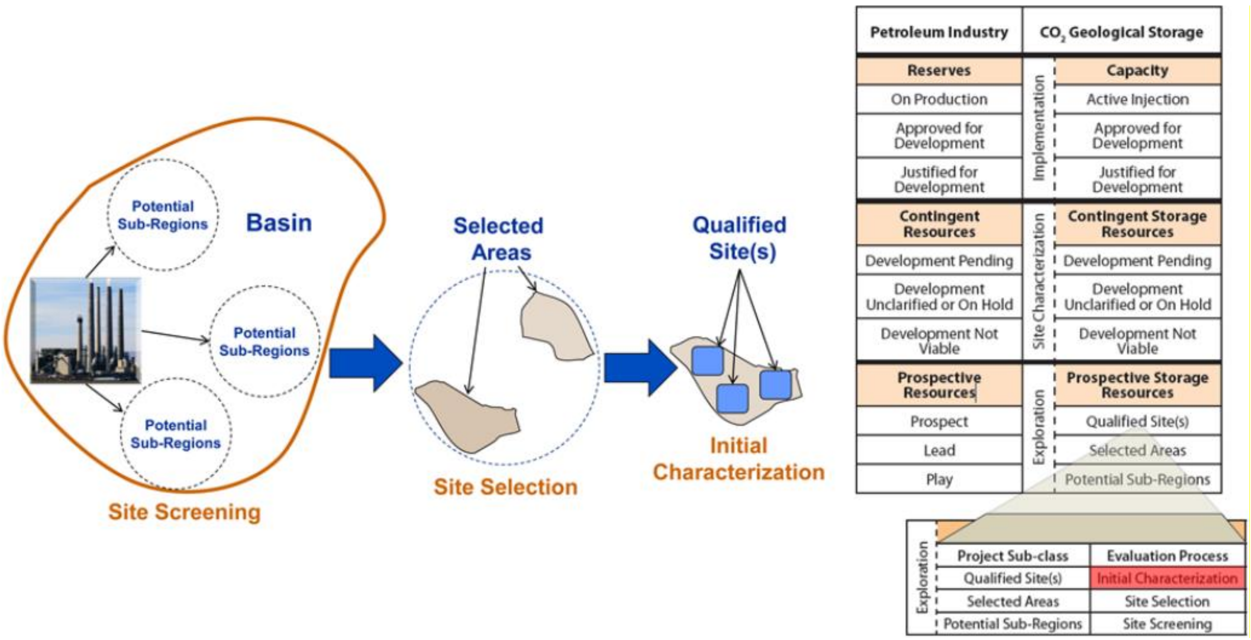
In addition, matching sources of CO_2 to potential storage sites—considering projections for future socio-economic development—is also particularly important. [5] Therefore, the site screening phase involves the evaluation of regions and sub-regions that are potentially suitable for safe CO_2 injection, 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) [69] 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). [69] 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. [5]

A preliminary estimate of an AoR [113] 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 rights-of-way (ROW). 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. [69]

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.” [69] 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 [114]



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. [5] 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. [16] 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 [115], including one specific to site characterization. [116] 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. [106] 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 site for deep well waste disposal, 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). [69] 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.). [5] 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. [69] 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. [106]

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. [69] 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. [5] Outreach and public engagement are also a critical component of a CO_2 storage project. [69] 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. [69]

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. [106]

5.4.3 Permitting (Injection)

Permitting requirements diverge significantly for UIC Class I and Class VI well. Generally, for both types of well classes, the pertinent 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. [117] 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. [118] 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. [119] 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)

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. [106]

Monitoring is a major component of the CO_2 injection operations. It is during the operational phase that the bulk of the MVA activities occur, 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. [120] 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

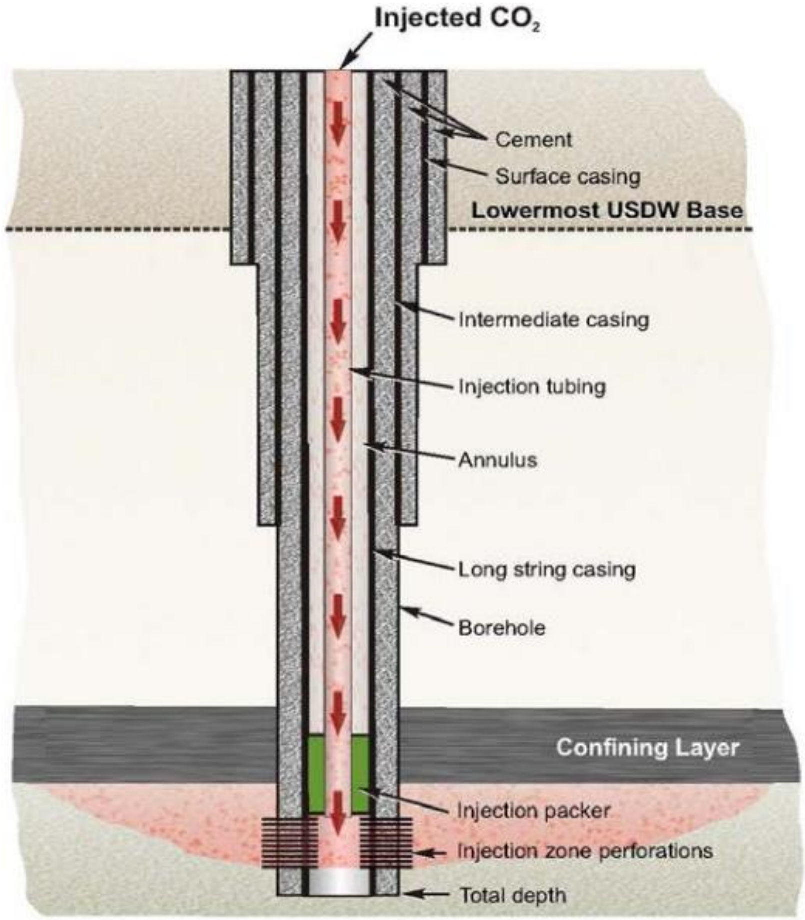
Storage of CO_2 in saline reservoirs is an attractive option for CCS operations. For instance, the storage resource potential for saline reservoirs is estimated to be substantial. [15] Additionally, saline storage capacity potential is much greater than that for depleted oil and gas reservoirs, and saline reservoirs are also widespread geographically, providing more opportunities for CO_2 storage from many emission sources. [15] 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. [121] 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. CO_2 storage shares commonality with deep well waste disposal in that operations for both practices are based on one-way disposal and storage (no reproduction of the injected fluid expected).

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 the American Petroleum Institute, 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 the American Petroleum Institute, 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 [12]



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. [106] 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). [106] [122] 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. [123] 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

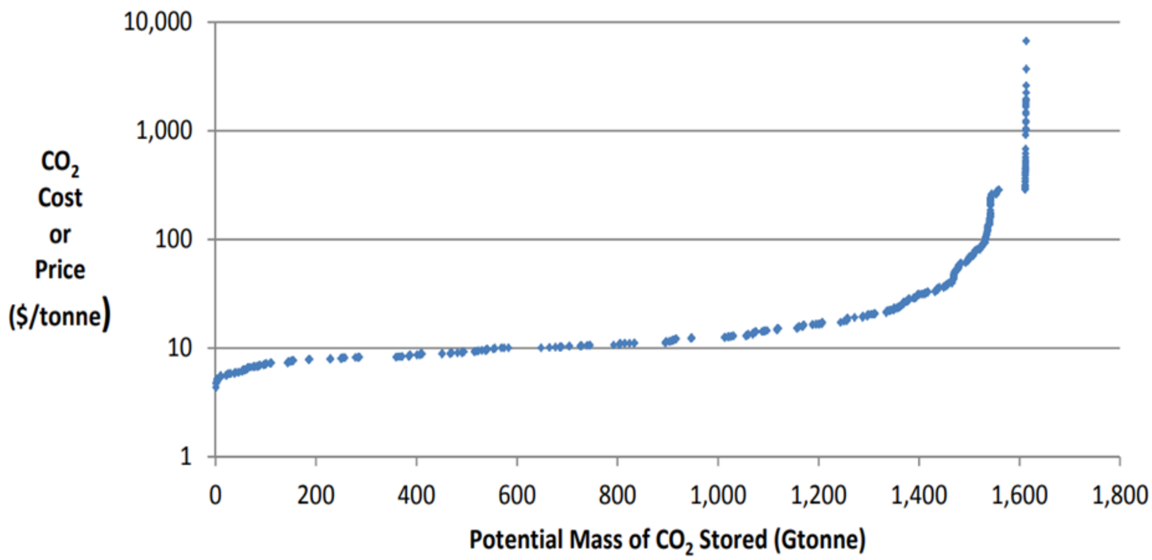
The potential costs of commercial-scale CCS are still not fully understood, particularly from a fully integrated (capture, transportation, and storage) perspective. [96] The challenge stems mainly from estimating storage costs, which is not a simple or straightforward process. [124] A typical storage project involves the time-intensive steps of site screening, site selection and characterization, permitting and construction, operations, and PISC and site closure. [125] Therefore, most CCS cost studies typically exclude, or assign a fixed constant for storage cost. [125] [126] However, such a simplistic approach ignores the large variation in storage cost due to differences in operational monitoring and reservoir quality. [124] [127]

The geologic heterogeneity of storage formation characteristics is the major driver of site specific cost variability. [128] 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. [92] [129] 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. [117] 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. [124] [128] [130] Typically, these are relatively thick, shallow (but still at a depth where CO_2 remains in a supercritical state) and highly permeable formations. [5]

The impact of regulation on cost, including monitoring requirements, liability and long-term management of CCS projects, remains uncertain. [126] 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. [6] 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. [117] 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, [117] injecting 3.2 Mt of CO_2 for 30 years, the lowest CO_2 break-even price is $4.30/tonne and the highest is over $1,000/tonne in 2011$, based on currently available technology. Exhibit 5-6 presents the cost-supply curve from the NETL baseline study. [117] 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 across 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. [125] 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. [131]

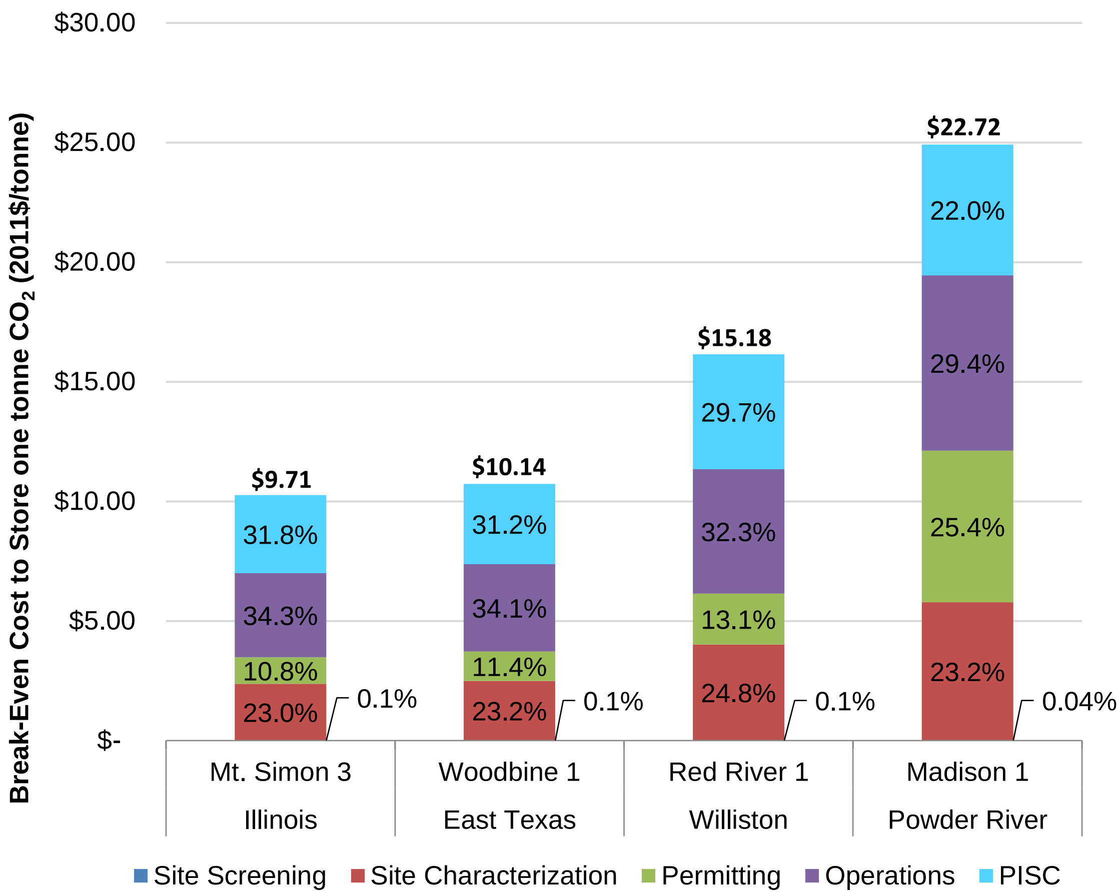
Exhibit 5-6. Cost supply curve for baseline case [117]



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. [92] 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) [92]



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. [130]

5.6 COMPARISON AND CONTRAST OF GEOLOGIC CO_2 STORAGE WITH UIC CLASS I OPERATIONS

The content presented in previous sections of this report show that hazardous and non-hazardous waste deep well disposal using UIC Class I 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, UIC Class I well 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 others) between waste disposal under UIC Class I wells as an analog to CO_2 storage using Class VI wells. In general, the injection and disposal of hazardous and non-hazardous waste into Class I injection wells since 1980 has been a relatively low-risk method management of liquid wastes and has a proven reputation of being safe and effective. [26] The safety record of Class I well operations (both hazardous and non-hazardous) is outstanding; a 1991 study by EPA concluded that Class I underground injection wells are safer (and pose less risk) than virtually all other waste disposal practices. [132] In fact, prior to UIC regulations in 1980, only a handful of significant cases of injected fluid migration occurred related to hazardous well operations (discussed in Section 6). None of the instances were reported as actually impacting a USDW. Since 1980, with the implementation of the UIC Program of the SDWA, no cases of USDW contamination have occurred due in part to stringent requirements of Class I hazardous and non-hazardous wells and a history of best-practices and lessons learned. Clark et al. [26] have indicated that the few instances of injected fluid migration that occurred prior to 1980 would likely not have occurred if regulations like those implemented in 1980 had been in place. Findings from these specific incidents can serve as learning opportunities for informing future CO_2 storage best practices and ensuring safe operations. [20]

There are several significant similarities between Class I 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; [2] however, there are substantial similarities and overlap for several requirements across all 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, 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. [5] 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. [20] As previously mentioned, hazardous Class I wells have more rigorous requirements than Class I non-hazardous wells. Many of these additional requirements are shared by Class VI wells (e.g., alarms and automatic shutdown equipment in injection wells, specialty well construction requirements like long string casing cemented to surface and detailed tubing and packer specifications, and requirements for ensuring integrity of confining zones). [6] [67]

While prominent similarities exist between the two well types, there are substantial differences between the two practices. One example is the varying levels of commercial application and experience of each practice. Waste disposal in Class I wells (or in early state-regulated injection wells prior to initiation of the SDWA and UIC Program) [133] has been a standard practice for nearly a century, whereas CO_2 storage in saline-bearing formations is still a relatively new concept that has been undergoing pilot and early commercial-scale testing. As another example, the types and physical state of the injected fluid are inherently different, with CO_2 being much more buoyant relative to in situ brine and requiring a pressure and temperature regime that enables the CO_2 to remain sustained in a supercritical state.

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 of key items pertaining to UIC Class I and UIC Class VI wells

Item	UIC Class I Wells (non-hazardous)	UIC Class I Wells (hazardous)	UIC Class VI Wells
Purpose	Disposal of non-hazardous waste into deep, confined rock formations below USDWs	Disposal of RCRA-defined hazardous waste into deep, confined rock formations below USDWs	Reduce CO_2 emissions into the atmosphere through injection of CO_2 into deep, confined rock formations for long-term storage
Technology Inception	Subsurface fluid disposal via well: 1930s U.S. EPA UIC regulations promulgated: 1980	Subsurface fluid disposal via well: 1930s Amended UIC Class I regulations to address RCRA specific to hazardous waste: 1988	Mid-1990s Class VI well promulgated: 2010
Active Well Count [3]	680	137	2
Formation Types	Saline-bearing formations	Saline-bearing formations	Saline-bearing formations
Injected Fluid Phase	Liquid waste	Liquid waste	Supercritical CO_2

Item	UIC Class I Wells (non-hazardous)	UIC Class I Wells (hazardous)	UIC Class VI Wells
Prominent Regulations	SDWA UIC Class I: ▪ 40 CFR 144 Subpart A ▪ 40 CFR 146 Subpart B ▪ 40 CFR 146 Subpart C	SDWA UIC Class I: ▪ 40 CFR 144 Subpart A ▪ 40 CFR 146 Subpart C ▪ 40 CFR 144 Subpart F ▪ 40 CFR 146 Subpart G ▪ 40 CFR 148 RCRA HSWA	SDWA UIC Class VI: ▪ 40 CFR 144 Subpart A ▪ 40 CFR 146 Subpart H Clean Air Act Subpart RR
Regional Prominence	Reference Exhibit 2-4	Reference Exhibit 2-4	Reference Exhibit 5-3
Potential National Storage Capacity	Not assessed	Not assessed	Saline-bearing formations, estimated: 2,379 – 21,633 billion tonnes of CO_2
Injection Well Design Considerations	Wells must be cased and cemented to prevent the movement of fluids into or between USDWs Inject fluids through tubing with a packer set immediately above the injection zone, or tubing with an approved fluid seal as an alternative Logging and testing required during construction of new wells	Additional requirements to those for non-hazardous Class I wells: ▪ Detailed requirements for tubing and packer ▪ Long string (inner) casing fully cemented to surface ▪ UIC Program approval of casing, cement, tubing, and packer prior to construction	Well materials compatible with fluids present in the subsurface Surface casing must extend through base of lowermost USDW and be cemented to the surface 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	Typically, one or more wells per waste-generating facility Dedicated disposal facilities that serve as centralized commercial injectors, accepting waste for disposal from several difference sources, typically have several injection wells	Typically, one or more wells per waste-generating facility Dedicated disposal facilities that serve as centralized commercial injectors, accepting waste for disposal from several difference sources, typically have several injection wells	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 Containment Mechanism	Structural trapping via shallower, low permeability formation	Structural trapping via shallower, low permeability formation	Structural trapping, stratigraphic trapping

Item	UIC Class I Wells (non-hazardous)	UIC Class I Wells (hazardous)	UIC Class VI Wells
Leakage Risks	Wellbore failures Improperly plugged or completed wells	Wellbore failures Improperly plugged or completed wells	Wellbore failures Caprock integrity – faults and fractures
Commercial-scale Examples	Numerous wells serving one individual facility with examples including: ▪ Monsanto Company, Louisiana ▪ H.J. Heinz Co., Michigan ▪ UOP, Louisiana ▪ California Specialty Cheese, California ▪ Eni US Operating Co., Alaska Commercial disposal facilities: ▪ River Birch Waste Disposal, Louisiana ▪ Kissack Water and Oil Service, Wyoming ▪ Matrix Oilfield Services, LLC, Wyoming Municipal waste examples: ▪ East Central Regional Waste Water Treatment Plant, Florida ▪ Lake Worth Water Treatment Plant, Florida ▪ City of Stuart, Florida ▪ Village of Wellington, Florida	Numerous wells serving one individual facility with examples including: ▪ Warner-Lambert (Pfizer, Inc.), Michigan ▪ K.C. Industries, LLC, Florida ▪ ArcelorMittal Burns Harbor, Indiana ▪ Great Lakes Chemical, Arkansas Commercial disposal facilities: ▪ Vickery Environmental Inc, Ohio ▪ Cornerstone Chemical Company, Louisiana ▪ TM Deer Park Services, Texas ▪ Veolia ES Technical Solutions, Texas ▪ TM Corpus Christi Services, Texas ▪ Vopak Logistics Services USA Deer Park, Texas	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) Class I injection well 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 would be to estimate the amount or rate of CO_2 that could be stored to a comparable volume of a commercial-scale Class I well if that well was converted to a CO_2 storage Class VI well. This example uses a non-hazardous Class I well permitted by the Florida Department of Environmental Protection (Permit ID: 178213-002-UO), which was permitted to inject upwards of 2.4 MMgal/d (with a 40–50-year life) of non-hazardous membrane softening reject waste water per year with roughly a density of 8.3 lb/gal according to the UIC Program's National Technical Working Group. [39] Supercritical CO_2 has a density of around roughly 40.1 pounds per cubic foot (5.34 lb/gal) when under approximately 3,100 psi and 170 °F (pressure and temperature typical of a CO_2 storage formation of a reasonable 7,300 ft depth). Under these conditions and based on the 2.4 MMgal/d injection rate of non-hazardous wastewater, this Class I well is equivalent to injecting approximately 2.1 Mt/yr of CO_2 based solely on volumetric and density considerations. This volume of CO_2 is more than triple the potential CO_2 capture rate from one 500 million standard cubic foot per day natural gas refinery for one year (650,000 tonnes of CO_2); which would be considered a small CO_2-generating source. [134] Conversely, it is expected that CO_2 storage operations may exceed the rate described in this example in the future (see Section 5.7.1.3 for the "CarbonSAFE" projects as one example). For instance, emissions from various CO_2-generating source types have been quantified; and upwards of 3.5 Mt/yr of CO_2 is equivalent to the volume of 90 percent of the CO_2 captured from one 550-megawatt supercritical pulverized coal power plant for one year. [135] However, the example discussed in this section demonstrates that existing UIC Class I injection operations have been occurring on scales comparable to volumes expected for CO_2 storage operations using Class VI wells under pilot-testing. 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), [101] and ICCS was approved to inject 1 Mt/yr for five years. [102] However, commercial-CO_2 storage volumes are expected to be significantly higher than those proposed at FutureGen 2.0 and at ICCS.

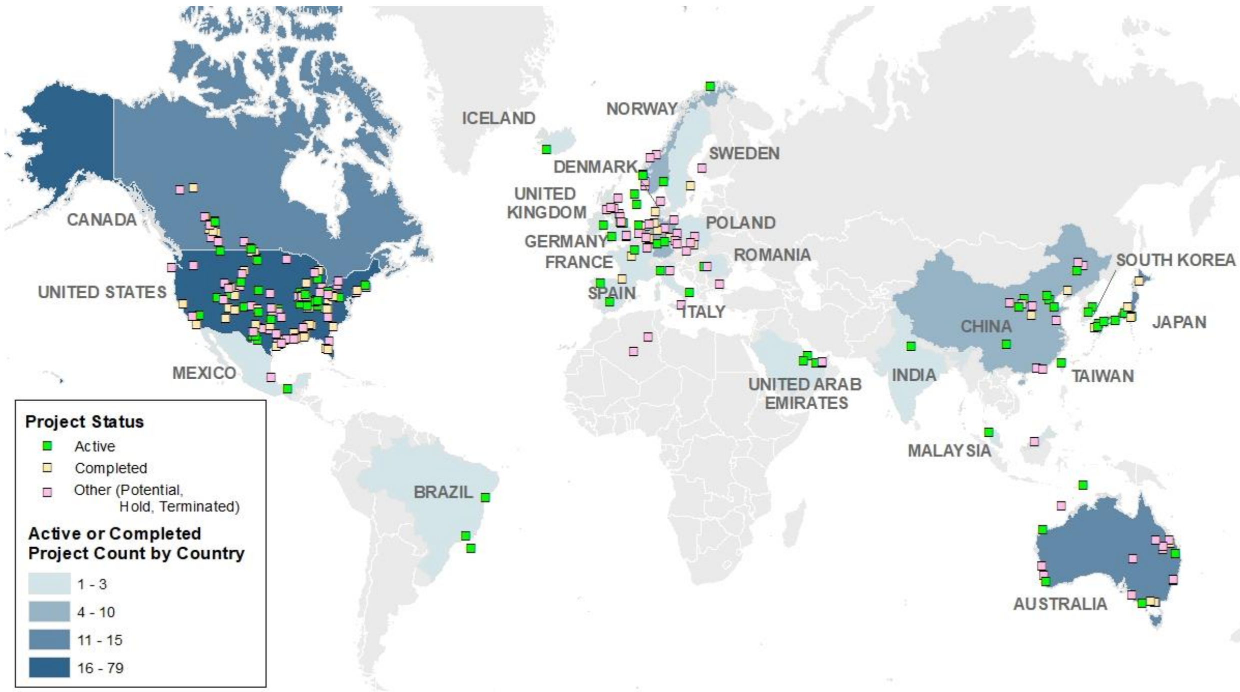
It is important to note that this evaluation utilizes the geostatic pressure and temperature gradients[m] to estimate pressure and temperature at depth, opposed to known site-specific conditions. Also, it does not allude to the size of the resulting CO_2 plume and pressure front and does not consider the injectivity and fracture pressure of the storage formation as part of the assessment.

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). [7] 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. [8] 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.

[m] 0.443 psi/ft for pressure and 15 °F/1,000 ft (25 to 30 °C/kilometer) for temperature. [180]

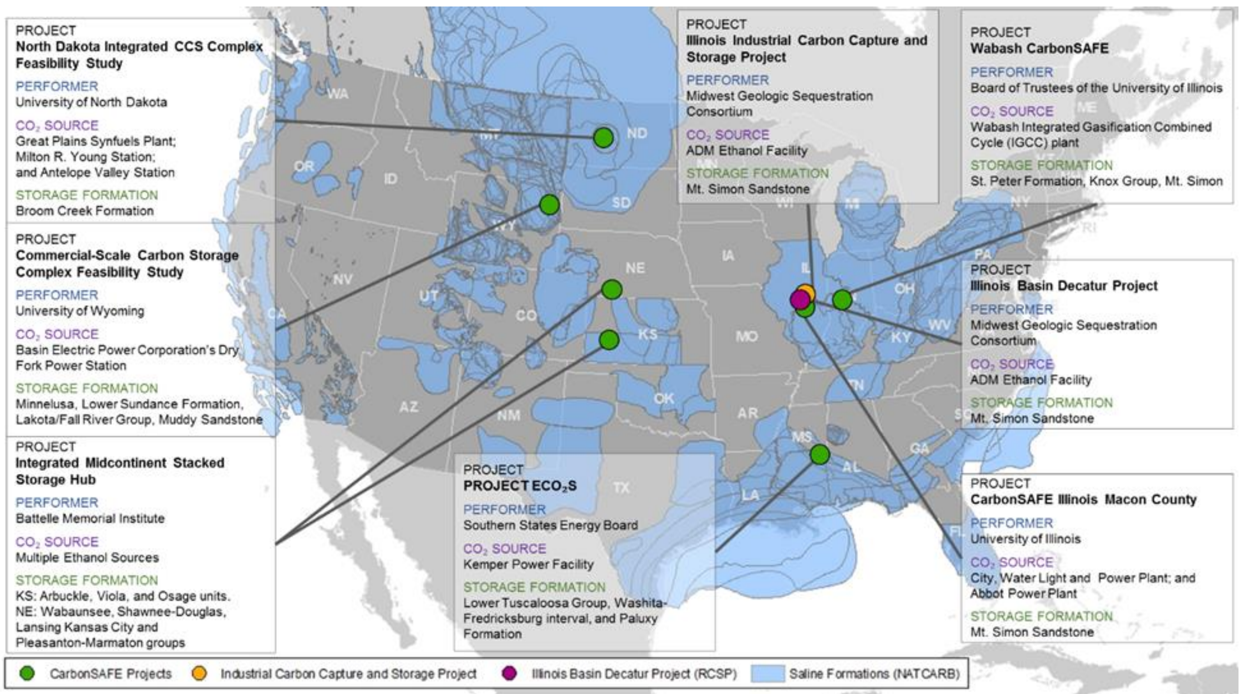
Exhibit 5-9. Map of active or recently completed CCS-related projects worldwide [7]



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 span 43 U.S. states and four Canadian provinces. [16] [100] [104] 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. [15] 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. [136] 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. [16] [18] [136] 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 the DOE-supported capture and storage projects, as well as proximity to saline-bearing formations attained from NATCARB [137]



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. [138] 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. [118]

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. [139] 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. [138] This project demonstrated that the Mt. Simon is a viable and important resource for deep saline storage. It has favorable porosity and permeability [138] 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. [140] [141]

5.7.1.2 Illinois Industrial Carbon Capture and Storage Project (ICCS)

The ICCS expands the operations of the IBDP to a commercial scale. [138] 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. [142] [143]

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. [144] This initiative has a series of sequential phases of development: Integrated CCS Pre-Feasibility, Storage Complex Feasibility, Site Characterization and Permitting, and Construction. [145] 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: [144] [146]

- 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 I WELL LEAKAGE RISK AND IMPLICATIONS FOR CLASS VI WELLS

Early failures associated with deep injection wells, like those at Hammermill Paper Company and Velsicol Chemical Company (mentioned in Section 2.2), as well as more recent examples associated with UIC Class I wells, demonstrates the potential threats of deep well waste injection and the need for and importance of regulations and safeguards. [28] Previous sections of this report have emphasized that Class I wells are designed and constructed to prevent the movement of injected wastewaters into USDWs, normally through suitable well construction that complies with the geology encountered, injection only into storage zones with the proper configuration of rock types that ensures injected fluids are received safely and contained indefinitely, and monitoring to ensure permeance and safe operations. Extensive pre-siting geological tests are performed to confirm that the injection zone can meet safety and operational criteria before a site is selected for installation of a Class I well. [28]

EPA has indicated that there are two significant leakage risks from which injected fluids can migrate to USDWs: 1) failure of the well or 2) improperly plugged or completed wells or other pathways near the well. EPA's extensive technical requirements for Class I wells are designed to prevent contamination of USDWs via these pathways. These requirements have been carried over in the Class VI rule as well. The 1980 UIC regulations address many of these risks associated with liquid waste disposal practices via deep well injection, and EPA suggests that many of the historic leaks pre-1980 would not have occurred under current UIC requirements. Since passage of the regulations, EPA and other organizations have conducted numerous studies of hazardous and non-hazardous Class I wells that demonstrate such failures are unlikely to occur. [28] Contamination due to well failure is caused by leaks in the well tubing and casing or when injected fluid is forced upward between the well's outer casing and the wellbore should the well lose mechanical integrity. Internal mechanical integrity is the absence of significant leakage in the injection tubing, casing, or packer. An internal mechanical integrity failure can result from corrosion or mechanical failure of the tubing, packer, or casing materials. External mechanical integrity is the absence of significant flow along the outside of the casing. Failure of the well's external mechanical integrity occurs when fluid moves up the outside of the well due to failure or improper installation of the cement. To reduce the potential threat of well failures, operators must demonstrate that there is no significant leak or fluid movement through channels adjacent to the wellbore before the well is issued a permit and allowed to operate. In addition, operators must conduct appropriate MITs every year (for hazardous wells) and every five years (for non-hazardous wells) thereafter to ensure the wells have internal and external mechanical integrity and are fit for operation (other Class I guidance summarized in Section 3.1.3). However, it is important to note that failure of an MIT, or even a loss of mechanical integrity, does not necessarily mean that wastewater will escape the injection zone. Class I wells have redundant safety systems to guard against loss of waste confinement (for instance, several layers of casing and cement, packers, and tubing among others). [28]

Additionally, Class I injection wells are monitored so that if migration of injection fluids were to occur it would be detected before reaching the USDW. Monitoring requirements include evaluating the characteristics of the injected fluid, flow rate and volume of injected fluid, injection pressure, annulus pressure, and background water quality of the injection zone. The collected data is submitted for review by regulators, who ensure conditions are in line with permitted ranges. [147]

The EPA Office of Solid Waste and Emergency Response performed a study to evaluate the relative risks posed by many waste management practices. The study found that, based on acute and chronic health risks and other health risks (such as cancer risks), groundwater sources affected, welfare effects, and ecological risks, Class I hazardous wells are safer than virtually any other waste disposal practice. [45]

The regulated safeguards described above were put in place due to a series of leakage events that occurred in the 1970s and early 1980s using deep well injection, many of which were documented in reports and studied by different government agencies. The following is a brief description of these events and highlights from those studies.

6.1 GAO CLASS I INJECTION LEAKAGE REPORT

In 1987, the U.S. GAO issued a report at the request of the Chairman, Environment, Energy, and Natural Resources Subcommittee, U.S. House of Representatives Committee on Government Operations. [148] The report, entitled *HAZARDOUS WASTE: Controls Over Injection Well Disposal Operations Protect Drinking Water*, was an assessment of the controls that were in place to protect drinking water from contamination by underground waste injection wells. As of 1987 there had been only two documented cases of contaminated drinking water, one additional case of leakage into Lake Erie (and suspected drinking water contamination), eight cases of nondrinking-water contamination, and two cases of soil contamination. These documented cases involved well malfunctions that resulted in contamination around the wellbore, where it is easy to detect. There have been no documented cases of groundwater contamination resulting from underground channels—as opposed to malfunctioning wells—but such contamination would be far more difficult to detect if it did not produce effects on the surface, or by chance show impacts in another well nearby. Moreover, a reliable method for sampling and testing large underground areas for contaminants has not been devised.

In both cases of known drinking-water contamination, the practice of allowing injection directly through the casing without a packer and tubing was the primary cause of the leakage. [28] This practice is not permitted under present regulations. Corrosion of the casing was suspected as the cause of leakage of injected fluids documented in the GAO study. Another safety feature required by current standards is double casing and cementing that extends below the base of the drinking-water zone. Since the GAO report, there have been no reported cases of significant drinking water contamination.

The following is a description of the leaks in the GAO report; these situations might be analogous to CO_2 storage situations, in the sense that they were the result of casing failures.

6.1.1 Drinking Water Contamination, Velsicol Chemical Company, Beaumont, Texas

In 1974 and 1975 the Velsicol Chemical Company (Velsicol) noted lower than normal injection pressures in one of its two injection wells in Beaumont, Texas, which were designed without packers and tubing (injection occurred directly through the casing). In June 1975, Velsicol shut down the well to determine the cause of the decreased injection pressures, and an inspection revealed numerous leaks in the well's casing. The well was then plugged, and a monitoring well installed between August and September 1976, which indicated that contaminated wastewater had leaked to a USDW. The leak and corresponding contamination occurred at a depth of 665 to 680 ft in the lower Chicot aquifer. The wastewater was pumped from the aquifer for 90 days via the monitoring well. After the contaminated waste was removed, another monitoring well was drilled about 50 ft away; water samples from this well showed that the contamination had not spread to that area. [148]

6.1.2 Drinking Water Contamination, Tenneco Oil Company, Chalmette, Louisiana

Leakage of injected waste caused contamination of a USDW at Tenneco Oil Company's well no. 1 in Chalmette, Louisiana, in 1980. Drinking water in the Chalmette area was contained in five aquifers, which extend from a depth of about 100 ft to a depth of 1,200 ft. Louisiana issued a permit for well no. 1 to pump oil-refinery wastewater containing phenols, sulfides, ammonia, and organic carbons into a sand reservoir located about 1,900 ft below the surface. The injection zone was 900 ft below the lowest drinking-water aquifer and was separated from it by a shale confining zone approximately 70 ft thick. The well was constructed without tubing and packer and waste was injected directly through the casing. In June 1980, the operator discovered that well no. 1 was leaking as injected wastes were found on the surface near the well. The well was immediately taken out of operation, and pressure tests conducted in February 1981 confirmed that the well casing—through which the wastewaters were pumped into the injection zone—was leaking at depths of between 140 – 147 ft and between 160 – 212 ft. The well was abandoned on February 26, 1981 and plugged with cement. The Louisiana Office of Conservation conducted a groundwater contamination investigation by installing 14 monitoring wells in 1982 (included six wells in the "100 ft" aquifer, six in the "200 ft" aquifer, and two in the "700 ft" aquifer) to determine the extent of contamination. Monitoring revealed that contamination occurred only in the "100 ft." aquifer and was confined to an area within 100 ft of the wellbore, which is in the uppermost portion of the drinking water aquifer. The contaminate leakage was believed to have migrated upward along the wellbore because monitoring results concluded there was no contamination in the two lower aquifers. A groundwater recovery system was installed and removed roughly 250,000 barrels of contaminated water between July 1982 and early 1986, resulting in reducing the phenol levels in the groundwater from 1,600 to 13 ppm. [148] Remediation efforts were believed to continue past 1986 until phenol levels reached a suitable level, but documentation is limited.

6.1.3 Surface Leak Followed by Suspected Groundwater Contamination, Hammermill Paper Company, Erie, Pennsylvania

In 1964, Hammermill Paper Company (Hammermill) began injecting up to 2 MMgal/d of pulping liquors into a limestone formation 1,600 ft below the surface. Previously, spent pulping liquors were discharged without treatment into Lake Erie. Wastes were pumped through a double-cased, cement-grouted steel pipe. Relatively high pressure (900 – 1,250 psi) was required to force the spent pulping liquors into the limestone formation. [149] In April 1968, corrosion caused the casing of Hammermill's no. 1 well to rupture, releasing spent pulping liquor to the land surface, which eventually flowed into Lake Erie for several weeks. [28]

In the early 1970s, complaints about a foul-smelling liquid seeping from an abandoned gas well in Presque Isle State Park near Erie were received by the Pennsylvania Department of Environmental Resources (PADER). PADER suspected that waste from Hammermill's injection wells, which were located about five miles west of the abandoned gas well, had migrated up the unplugged wellbore of the gas well. The Hammermill injection wells were having operational problems at the time due to casing corrosion. Field tests and investigations conducted by PADER and EPA between 1979 and 1982 failed to determine the source of the fluid seeping from the abandoned gas well. In fact, the fluid was like "black water,"[n] which is naturally found in deep formations in the area. No conclusive evidence was found that linked the fluid that seeped from the Presque Isle well to the Hammermill injection wells. All three of Hammermill's injection wells were plugged and abandoned in September 1972 due to corrosion problems. [150]

6.1.4 Other Examples

Between 1975 and 1984, hazardous waste leakage into non-drinking-water aquifers occurred at eight separate facilities, and soil contamination occurred at two other facilities according to GAO. [148] Contaminants from these ten incidents were not expected to migrate to an extent that would pose a threat to drinking water aquifers. The problems associated with these eight leakage events, generally disclosed or confirmed by MITs, centered on casing and/or tubing corrosion or deterioration. The most notable of these cases occurred at a commercial facility in Ohio in 1983. The operators did not discover leaks in the bottom part of the casing of their wells until substantial amounts of waste escaped into an unpermitted zone. Fortunately, this zone was separated from the bottom of the lowermost drinking-water aquifer by more than 1,500 ft, 1,000 ft of which was confining, low permeability rock formations. As a result, the drinking water remained uncontaminated. The problem that resulted in leakage from this facility was detected during an MIT conducted as part of monitoring for the wells' UIC injection permit. The operator was subsequently fined $12.5 million for these and other violations, and the problem wells were repaired. [28] [148]

Regarding the other two leakage incidents where leakage resulted in soil contamination, well blowouts were documented as the cause. In one case, corrosion caused the tubing to separate,

[n] Black water is listed as naturally occurring formation water that contains iron sulfides that result from the reaction between hydrogen sulfide and metals in the water. [148]

causing the well to blow out and allowing the waste to flow to the surface. In the other case, several blowouts occurred during major maintenance operations. While the specific industrial operation associated with the leak was not reported, the blowouts were believed to have been caused by CO_2 that was thought to have been generated during these operations. The contaminated soil was cleaned up at both sites, and no drinking water was contaminated. Both wells were plugged and abandoned because of continued operating problems. [148]

6.2 UIPC, GAO, AND U.S. EPA ANALYSES OF CLASS I MECHANICAL INTEGRITY FAILURE

In the mid-1980s, UIPC and GAO conducted studies that described past Class I well malfunctions in the United States and discussed how current Class I regulations would minimize the possibility of future failures. The UIPC study published in 1986 included case histories of Class I well sites or facilities with reported histories of operational problems. Well malfunctions were identified at 26 facilities, involving 43 wells, suggesting an overall well malfunction rate of approximately nine percent of the 500 Class I wells reported to exist at the time. Only six wells experienced malfunctions resulting in leakage into a USDW. [28] The GAO study, published in 1987, focused on Class I failures resulting in aquifer contamination, in which the GAO reviewed the cause of each incident to conclude whether regulations in place would have prevented it from occurring. The 1987 GAO study reported only two cases of drinking water contamination from Class I wells, one case of suspected contamination, and eight other documented cases of non-drinking water aquifer contamination [28] [148] For most of the documented facilities in the UIPC study where well malfunctions occurred, as well as all of the cases in the GAO study, failing wells had been constructed and injection had occurred prior to the implementation of the 1980 UIC standards. In fact, most of the documented malfunctions reported in the UIPC study were related to design, construction, or operating practices that are not allowed under UIC regulations. [28]

EPA performed a separate analysis of all non-hazardous and hazardous Class I mechanical integrity failures (in a selected group of states) during the 1988 to 1991 timeframe. The study was published in 1993. [37] During this study, EPA studied more than 500 Class I non-hazardous and hazardous wells and identified the following: [28] [37]

> 130 cases of internal mechanical integrity failures (leakage in the injection tubing that can result from corrosion or mechanical failure of the tubular materials) were reported. These internal mechanical integrity failures were detected during well operation by the continuous annulus monitoring systems or by MITs. The wells were shut-in until they were repaired. Of these mechanical integrity failures, 42 percent occurred in the tubing and 23 percent involved the long string casing. One external mechanical integrity failure (flow along the outside of the casing) occurred which was detected by a routine external MIT and did not involve wastewater migration. Only four cases of significant non-hazardous wastewater migration were detected with three of the cases detected by monitoring wells. The fourth potential wastewater migration case was discovered when a Class I well was drilled into the same formation. None of these failures were believed to have affected a USDW.

EPA performed a second analysis summarizing mechanical integrity failures in Class I non-hazardous and hazardous wells between 1993 and 1998 as an update to the 1993 study. [38] The 1993 through 1998 wells study is based on information from 100 percent of Class I hazardous wells and 85 percent of all non-hazardous wells active in the United States during that timeframe. EPA found that mechanical integrity failures of all types dropped by half in every state, except Texas. Mechanical integrity failures for all Class I wells in Texas increased two-fold during the assessment period compared to the previous study period. In fact, a relatively high Class I well mechanical integrity failure rate of 65 percent was indicated. As with the 1993 study, none of the failures affected a USDW. [28]

6.3 FOLLOW-UP AND LESSONS LEARNED FROM CASE STUDIES

In March 2001, EPA completed a study of the risks to human health and the environment associated with hazardous waste disposal practices, as required by the Land Disposal Program Flexibility Act of 1996 (Public Law 104-119). [28] The report compiled information on existing Class I waste disposal activities to determine if existing programs were adequately protective, or new regulations were needed to ensure safe management of these wastes. All Class I wells are designed and constructed to prevent the movement of injected wastewaters into USDWs. Class I fluids are injected into brine-saturated formations thousands of feet below the land surface; EPA concluded that the injected fluids are likely to remain confined for a long time. As part of this study, EPA concluded that there are two potential pathways through which injected fluids can migrate to USDWs: wells could have a loss of waste confinement and be improperly plugged or completed, or other pathways near the well can allow fluids to migrate to USDWs. EPA's technical requirements for Class I wells at 40 CFR 146 (for all Class I wells) and 148 (for hazardous waste wells) are designed and in place to prevent contamination of USDWs via these pathways. Many of the subsurface liquid waste disposal leaks that occurred prior to inception of the UIC Program and subsequent requirements are believed by EPA to have likely not occurred if existing UIC requirements were in place at the time. Overall, this study concluded that EPA has learned much about what makes Class I wells safe and what practices are unacceptable based on review of a long Class I operational history. The UIC regulations are based on the concept that injection into properly sited, constructed, and operated wells is a safe way to dispose of wastewater, and that Class I injection practices offer several safeguards against failure of both Class I non-hazardous and hazardous waste wells. [28]

6.4 PUBLIC CONCERN

Despite a long history of safe injection operations, the concept of subsurface injection and associated facilities can, at times, be the focus of undesired local hostility, and may even eventually lead to litigation. Opposition from communities near operating injection facilities can be strong, especially facilities injecting wastes not generated on-site. In general, facilities far from population centers are subject to less local opposition. Local concerns include:

- Decrease in property value
- Accidents

- Leaking surface impoundments
- Transportation hazards

Convincing the local community that waste containment is safe, and that the probability for leakage is low, can be a difficult task. The past leakage events described above have been cited by environmental groups in their opposition to the underground disposal of hazardous liquid wastes. For example, the activist web site ProPublica stated that “some experts see the well failures and leaks discovered so far as signs of broader problems, raising concerns about how much pollution may be leaking out undetected. By the time the damage is discovered, they say, it could be irreversible.” [151] Yet no USDW has been contaminated by Class I injection wells since more stringent regulations were enacted in the 1980s.

As indicated by several studies from both industry and EPA, and highlighted in the immediate sections above, the practice of deep well subsurface waste disposal is safe and effective and poses little risk (reported as one in one million to one in ten quadrillion) to the environment if conducted properly. [28] [45] [46] However, various advocacy groups have challenged the effectiveness of subsurface waste disposal injection regulation and the general implementation of the practice.[o] [46] In fact, one paper states that, “Despite the considerable reliance on underground injection for disposing of hazardous wastes, neither the effective injection of fluids nor their safe containment can presently be assured.” [152] Even with opposition, underground liquid waste disposal today is still a viable, safe, and widespread liquid waste disposal practice.

[o] The following are documents reported by Rish [46] as opposing subsurface liquid waste disposal: 1) Gordon, W., and Bloom, J. 1985. Deeper Problems: Limits to Underground Injection as a Hazardous Waste Disposal Method. Natural Resources Defense Council, Inc.; 2) MacLean, A., and Puchalsky, R. 1994. Where the Wastes Are: Highlights from the Records of the More than 5,000 Facilities that Received Transfers of TRI Chemicals. OMB Watch and Unison Institute, April.; and 3) Sierra Club Legal Defense Fund. 1998. In: E.P. Jorgensen (Ed.), The Poisoned Well: New Strategies for Groundwater Protection. Island Press, Washington, D.C.

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 waste disposal via deep well injection 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 UIC Class I well injection, as well as deep well injection operators prior to implementation of the UIC program, provide 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 of leakage-related incidences that have occurred. The potential leakage risks associated with deep well injection include fluid migration away from the produced reservoir and into USDWs or to the surface. Prior to the UIC Class I well regulations, there had been noted historical cases of leakage associated with deep well injection, although relatively few. In cases where leakage was identified, it was caused by failures associated with the injection well, like corrosion impacts, or poorly designed or constructed wells, the presence of improperly plugged and abandoned wells, and injection under excessive pressures. [28] Prominent examples include the Hammermill Paper Company's No. 1 well in Erie, PA in the 1960s, and the Velsicol Chemical Company well in Beaumont, TX in the 1970s.

Recognizing that injected waste water can migrate away from the intended injection interval due to faulty well design, construction, operating practices, or the presence of pathways for migration near the injection zone, EPA passed the UIC regulations for Class I nonhazardous and hazardous wells in 1980. These regulations are based on the idea that injection into properly constructed and operated wells would provide a safe means to dispose of waste. [28] Studies conducted by the GAO [148] and UIPC [44] have found a substantial number of failing injection wells in the U.S. that had been constructed and injection had commenced prior to the implementation of the 1980 UIC rules. [28] But even with implementation of the UIC regulations, studies assessing Class I well performance conducted by EPA have noted instances where mechanical integrity issues have still occurred; [38] emphasizing the need for careful adherence to the regulations, and implementation of best practices. Studying analogs to CO_2 storage helps to improve overall understanding of both the technical concept and its application—in this case, large-scale injection and geological storage of CO_2 in saline-bearing reservoirs involving millions of tonnes of CO_2. [20]

There are significant similarities that exist between deep well waste disposal using UIC Class I wells and CO_2 geologic storage (and essentially full-scale CCS) using Class VI wells. Significant similarities noted in this report between the two practices include the injection of a fluid for long-term underground storage or disposal, the need for an adequately thick caprock to ensure long-term containment (ideally with a secondary caprock above the primary seal to prevent mobility/leakage), and adequate porosity and permeability to enable effective storage capacity 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. [5] 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. [20] 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 I 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 I wells. [67] 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 I wells used for waste disposal purposes. [116] States with primacy for Class I permitting have to apply Federal regulations as a minimum standard but may add specific regulations to meet local, state needs (see Appendix E: Overview of the Six States with the Most Class I Wells). Currently, North Dakota is the only state that holds primacy over Class VI wells in addition to the other UIC well classes. [153]

While similarities exist between deep well waste disposal and saline-based geologic storage of CO_2, there are substantial differences between the two practices. For example, there are varying levels in the commercial application and experience of each practice. Deep well waste disposal is a widely commercialized industry in the United States that has undergone relatively safe and successful operations. 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 [7] [9] [18] 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. [9] [10] Another difference between the two practices is the types and physical state of the injected fluid (e.g., supercritical CO_2 is typically much more buoyant than most Class I injection wastes). The supercritical CO_2 has a higher potential than Class I wastes to migrate vertically in the subsurface and threaten intrusion into shallower formations, including drinking water sources. [21] As a result, the Class VI regulatory framework needed to be specifically tailored to address CO_2 related storage challenges.

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. [10] Additionally, Rai et al. [10] identified multiple non-technical factors that have facilitated commercial adoption of industries analogous to CO_2 storage that are worth noting. 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 CO_2 EOR [55] and underground natural gas storage [154]) critical findings from the experience of Class I well operations 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. [10] 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. [155] 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. [135] 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. [156] [157]
- 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: RELEVANT SAFE DRINKING WATER ACT UNDERGROUND INJECTION CONTROL REQUIREMENTS

Exhibit B-1 lists and describes sections of the Safe Drinking Water Act (SDWA) that focus on subsurface injection activities, overseen under the United States Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Program.

Exhibit B-1. SDWA sections related to UIC Program [47]

Section	Description
1421	• Identifies minimum requirements states must meet to be granted primary enforcement authority (primacy) for the UIC Program • Addresses how underground injection can endanger USDWs
1422	• Outlines process for state primacy applications • Provides application timelines and public participation requirements for states seeking primacy; EPA runs the UIC Program in a state that does not assume primacy • Specifies how tribes may apply for primacy
1423	• Sets forth enforcement of the UIC Program • Describes civil and criminal actions including amount of any penalty levied
1425	• Sets forth enforcement of UIC Program • Describes civil and criminal actions including amount of any penalty levied • Describes optional demonstrations a state may make for portion of UIC Program relating to oil and natural gas operations • 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
1426	Requires the EPA Administrator to determine the applicability of monitoring methods and to submit a report to Congress on Class V wells; report to Congress includes information on Class V well inventory, well types, design and construction recommendations, and risks associated with discharged wastes
1431	• Authorizes emergency powers for EPA • Gives EPA authority to act to protect public health if substantial endangerment of USDWs is imminent
1442	• Gives EPA authority to conduct research, studies, training, and demonstrations • Addresses ways to identify improved methods for protecting USDWs
1443	Establishes grants for primacy programs; each year, states receive EPA funding under this section to help them implement their UIC programs

APPENDIX C: STATE AND FEDERAL AGENCIES TRACKING UNDERGROUND INJECTION CONTROL CLASS I WELL DATA

Data compiled to generate Exhibit 2-4 was collected from the corresponding regulating bodies (state or federal level) overseeing Class I wells within their state or region. Only publicly-available data, or data acquired by contacting representatives from each agency, was collected and used for this analysis. Many of the state agencies (like Alaska and Ohio as examples) featured well data on publicly-available sources. States like Kansas and Colorado did not feature well data publicly. Because of the disparity across regulating bodies for reporting requirements, level of public data availability, accuracy, and vintage, this list (provided in Exhibit C-1) is not expected to be fully comprehensive of all Class I wells.

Exhibit C-1. Class I well data sources by state and regulating agency

State	Regulating Agency	Link or Method of Data Retrieval
Alaska	United States Environmental Protection Agency (EPA) Region 10 Underground Injection Control (UIC) Program	https://epa.maps.arcgis.com/apps/webappviewer/index.html?id=973a4673947a42b3b9d14ec57401f5f1
Arkansas	Arkansas Department of Environmental Quality	https://www.adeq.state.ar.us/home/pdssql/pds.aspx
California	EPA Region 9 UIC Program	https://www.epa.gov/uic/underground-injection-control-permits-9
Florida	Florida Department of Environmental Protection	http://www.dep.state.fl.us/water/uic/index.htm
Illinois	EPA Region 5 UIC Program	Personal communication with agency
Indiana	EPA Region 5 UIC Program	Personal communication with agency
Kentucky	Kentucky Geological Survey	http://kygs.maps.arcgis.com/home/webmap/viewer.html?webmap=9380ec4940cd46c9b2c65a1160753f6f
Louisiana	Louisiana Department of Natural Resource	http://sonris.com/
Michigan	EPA Region 5 UIC Program	Personal communication with agency
Mississippi	Mississippi Department of Environmental Quality	Personal communication with agency
Nebraska	Nebraska Department of Environmental Quality	Personal communication with agency
New Mexico	State of New Mexico Oil Conservation Division	http://ocdimage.emnrd.state.nm.us/imaging/Default.aspx
North Dakota	North Dakota Department of Health	http://www.ndhealth.gov/ehs/OpenRecords.asp
Ohio	Ohio Environmental Protections Agency	http://www.epa.ohio.gov/ddagw/uic.aspx
Oklahoma	Oklahoma Department of Environmental Quality	http://www.deq.state.ok.us/lpdnew/UIC/UICMap.html
Texas	Texas Commission on Environmental Quality	http://www15.tceq.texas.gov/crpub/index.cfm?fuseaction=addnid.IdSearch
Tribal Regions	EPA Region 6 UIC Program	Personal communication with agency
Wyoming	Wyoming Department of Environmental Quality	http://deq.wyoming.gov/wqd/underground-injection-control/resources/class-i/

APPENDIX D: RESOURCE CONSERVATION AND RECOVERY ACT REGULATIONS

Exhibit D-1 shows United States Environmental Protection Agency regulations under Title 40 of the Code of Federal Regulations (CFR) - Protection of the Environment for the Resource Conservation and Recovery Act (RCRA) that pertain to areas of non-hazardous (solid waste) and hazardous wastes, used oil, and underground storage tanks.

Exhibit D-1 RCRA 40 CFR regulations [158]

Part		Title
239	Non-Hazardous Waste	Requirements for State Permit Program Determination of Adequacy
240		Guidelines for the Thermal Processing of Solid Wastes
241		Solid Wastes Used as Fuels or Ingredients in Combustion Units
243		Guidelines for the Storage and Collection of Residential, Commercial, and Institutional Solid Waste
246		Source Separation for Materials Recovery Guidelines
247		Comprehensive Procurement Guideline for Products Containing Recovered Materials
254		Prior Notice of Citizen Suits
255		Identification of Regions and Agencies for Solid Waste Management
256		Guidelines for Development and Implementation of State Solid Waste Management Plans
257		Criteria for Classification of Solid Waste Disposal Facilities and Practices
258		Criteria for Municipal Solid Waste Landfills
259		Reserved
260	Hazardous Waste	Hazardous Waste Management System: General
261		Identification and Listing of Hazardous Waste
262		Standards Applicable to Generators of Hazardous Waste
263		Standards Applicable to Transporters of Hazardous Waste
264		Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities
265		Interim Status Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities
266		Standards for the Management of Specific Hazardous Wastes and Specific Types of Hazardous Waste Management Facilities
267		Standards for Owners and Operators of Hazardous Waste Facilities Operating Under a Standardized Permit
268		Land Disposal Restrictions
270		EPA Administered Permit Programs: The Hazardous Waste Permit Program
271		Requirements for Authorization of State Hazardous Waste Programs
272		Approved State Hazardous Waste Management Programs
273		Standards for Universal Waste Management
279	Other	Standards for the Management of Used Oil
280		Technical Standards and Corrective Action Requirements for Owners and Operators of Underground Storage Tanks
281		Approval of State Underground Storage Tank Programs
282		Approved Underground Storage Tank Programs
283 – 299		Reserved

APPENDIX E: OVERVIEW OF THE SIX STATES WITH THE MOST CLASS I 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 numbers of Class I wells. The well volume pertaining to each state discussed below can be referenced in Exhibit 3-4. [3]

Florida

Florida has the most Class I injection wells in the United States (roughly 31 percent of all Class I wells). [3] The Florida Department of Environmental Protection is responsible for the administration and enforcement of underground injection wells in Florida. The Underground Injection Control (UIC) Program is regulated under Florida Administrative Code 62-528. Unlike the federal rules, Florida's rules prohibit the construction of new underground injection wells for the injection of hazardous waste.

Most of the Class I injection facilities in Florida dispose of non-hazardous, secondary-treated effluent from domestic wastewater treatment plants. The main reasons for the widespread use of deep well disposal of this waste stream type in Florida is primarily due to a shortage of available land for waste disposal, strict limitations on surface water discharges, the presence of highly permeable injection zones, and cost considerations. [28] The injection wells are required to be constructed, maintained, and operated so that the injected fluid remains in the injection zone, and unapproved interchange of water between aquifers is prohibited. Applicants for Class I wells are required to assure, through a performance bond or other appropriate means, that resources necessary to plug and abandon the wells are available, including post-closure monitoring and any corrective action resulting from this monitoring. The nature of some of these injected fluids requires that the wells be constructed of corrosion-resistant materials; this construction is a potential analog for carbon dioxide injection. [159] Class I injection wells are required to be monitored so that if migration of injection fluids were to occur it would be detected before reaching the USDW (monitoring wells required to be located within 150 feet of the injection well). Testing is conducted on all Class I injection wells at a minimum of every five years to determine that the well structure has integrity. [160]

Texas

Although second on the list for total number of Class I wells, Texas has more than twice as many hazardous waste injection wells as the other five states combined (nearly 57 percent of all Class I hazardous wells). Texas has specific rules relating to UIC and provides permits for certain classes of wells in appropriate geologic locations. For instance, Texas provides operators the option to dispose of waste in a salt cavern, which is a regionally-specific geologic formation. The state standards generally include the federal standards, as well as more specific criteria, state applications, and fees for application and operation of underground injection wells. The Texas Commission on Environmental Quality (TCEQ) UIC Program and the Railroad Commission of Texas Technical Permitting Section share the responsibility for permitting and enforcing the standards. The governing laws and regulations include the Injection Well Act, Texas Water Code

27; the Solid Waste Disposal Act, Texas Health and Safety Code 361; and the UIC: 30 Texas Administrative Code (TAC) 331.1 to 331.251. [161] [162]

Much like federal UIC regulations, 30 TAC §331.62, which outlines the construction standards for Class I wells in Texas, states that *"All Class I wells shall be designed, constructed and completed to prevent the movement of fluids that could result in the pollution of an underground source of drinking water."* The following guidance is given by the TCEQ as design requirements for Class I wells: [162]

- Surface casing should be set at least into the first confining bed below the lowest USDW, as determined by well logging prior to the casing installation. Installation of an extra string of casing may be required where and if subsurface geologic sections contain more than one USDW.
- All Class I wells shall inject fluids through tubing with a packer as per Commission rule 30 TAC §331.62(a)(1)(B).
- Since the injection tubing is always in contact with the waste, the characteristics of injection fluid must be considered carefully to insure compatibility of the tubing material with the injected wastes as per 30 TAC §331.62(a)(1)(B)(ii). The TCEQ indicates that injection tubing is typically constructed of ferrous alloys or non-ferrous materials such as fiberglass.
- The injection tubing could be subject to contraction and expansion caused by variations in temperatures, and to tension, compression, and hydraulic pulsation effects. Operators must consider adequate safety factors when designing tubing and packers to comply with 30 TAC §331.62(a)(1)(B)(vii).
- Class I wells must be cased and cemented to prevent movement of fluids into or between USDWs or freshwater aquifers, and to prevent movement of fluids out of the injection zone per 30 TAC §331.62(a)(5). 30 TAC §331.62(a)(6) imposes more specific requirements on cementing of new wells constructed after May 25, 1995, and on wells converted for use as Class I injection wells after that date.
- Perforated-casing (cased-hole) completions are most commonly used for bottom hole completion of waste disposal wells in Texas. The screen and gravel pack method, as well as the open-hole method, can also be used in bottom-hole completions.

Wyoming

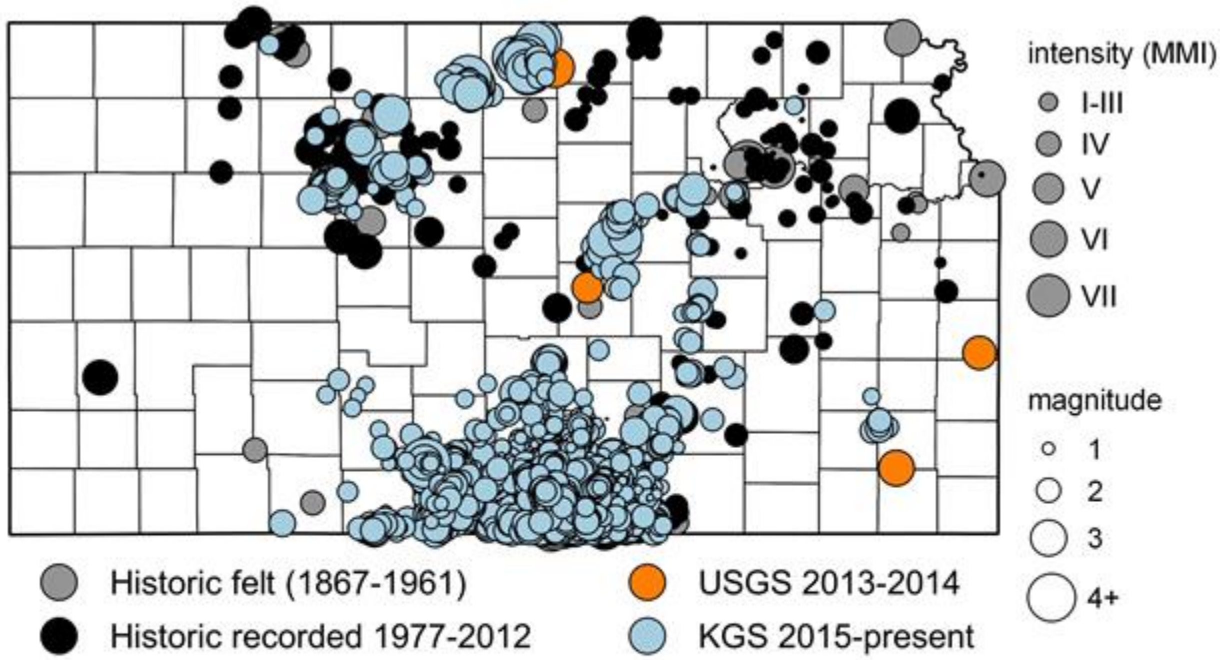
Wyoming regulations allow hazardous waste wells; however, all currently permitted Class I wells are for the injection of non-hazardous waste. The Wyoming Administrative Rules in Water Quality Rules and Regulations Chapter 27 governs the installation and operation of Class I wells. Section 6 of the regulations deals with permitting requirements, including tests to determine the fracture pressure of the injection zone and special conditions for hazardous wells. Sections 12 and 14 list the construction standards and siting conditions. Section 15 covers environmental monitoring, including an annual requirement to shut down the well to measure the pressure fall-off curve. Section 16 covers financial responsibility. Like federal UIC and other state-implemented financial responsibility requirements, operators in Wyoming must assure, through a surety bond or other appropriate means, that they have adequate resources to cover the estimated cost to close, plug, abandon, and maintain post-closure care for the underground injection operation. [163] The Wyoming Department of Environmental Quality provides helpful guidance for potential well operators to calculate critical injection parameters, including the limited surface injection pressure (which is roughly 90 percent of the formation fracture pressure), the area of review (AoR), cone of influence (area around a well in which increased discharge zone pressures caused by the injection would be sufficient to force fluids into a USDW), and area of emplaced waste (volume calculation to determine the maximum area that the injected waste could occupy). [164]

Kansas

Kansas has primacy for UIC well classes I – V. Kansas has generally adopted the federal requirements governing UIC wells in 40 Code of Federal Regulations (CFR) 146.12 and 40 CFR 146.65; most of the exceptions to the federal regulations deal with Class III salt solution mining wells. The Kansas Department of Health and Environment (KDHE), Division of Environment, Bureau of Water, Geology & Well Technology Section enforces the Class I underground injection well requirements. The UIC Program is regulated under Kansas Administrative Regulations (K.A.R.) 28-46; monitoring and reporting requirements for Class I wells are specifically called out in K.A.R. 28-46-30. The injection of hazardous or radioactive waste near a USDW is prohibited in the state; however, wells that meet certain requirements for an underground injection well permit under the federal Safe Drinking Water Act can obtain a hazardous waste disposal facility permit. Underground injection wells in Kansas are subject to various state fees, certain state treatment, storage, and disposal facility permit requirements, and more stringent management requirements. Class I injection wells are required to be continuously monitored for pressure, volume, and flow rate; data must be reported to the state monthly. Monitoring wells that can detect migration of injection fluids are required; the number and placement of which are determined on a case-by-case basis by the KDHE. Class I permits are in effect for ten years and are renewable. [161] [165]

In Kansas, there is concern about inducing earthquake activity from underground waste disposal operations. For instance, from 2014 through 2016, Kansas experienced approximately 590 +2.5 magnitude earthquakes according to the United States Geological Survey Earthquake Hazards Program. [70] Recent earthquake frequency is up dramatically from historic levels in the state, most likely attributed to underground oil and gas waste disposal (see Exhibit E-1). [166]

Exhibit E-1. Map of historic and recent earthquake activity in Kansas, including magnitude and intensity (Modified Mercalli Intensity [MMI]) [166]



Source: Kansas Geological Survey

Geologic conditions are present in Kansas that can significantly reduce the potential for injection induced earthquakes. For instance, KDHE indicates that the Arbuckle Formation is the preferred disposal formation and meets KDHE requirements because it is a thick, permeable, and porous formation, which limits pressure build-up in the formation that might cause earthquakes. Additionally, documented faults within the Arbuckle are limited in extent. Forty-six of the 47 active Class I disposal wells in Kansas use the Arbuckle as the disposal formation. The concern for inducing seismicity is one of the reasons why KDHE regulates Class I injection wells. Specific regulatory requirements implemented by KDHE that significantly decrease the potential for Class I disposal well operations to cause earthquakes include the following: [167]

- Prohibits operators to inject fluid using surface pressure (i.e., pumps) per regulation K.A.R. 28-46-28 and the UIC permits issued by KDHE limit injection to "gravity" at the surface. Gravity injection allows only the amount of fluid to be injected that the formation can naturally accept thereby limiting pressure build-up in the disposal formation reducing the potential of rock movement at a fault.
- Injection pressure is limited below the rock fracture pressure per KDHE regulation K.A.R. 28-46-28. This prevents the injection from fracturing the rock or opening fissures, which could activate a fault.
- Requires operators to identify faults near proposed injection wells.
- Requires the injection well owner/operator to conduct an AoR for injection wells of a minimum of 1-mile (mi) radius around the well location for non-hazardous injection and

a 2.5-mi radius for hazardous waste injection wells per K.A.R. 28-46-32. Faults within this area must be identified and evaluated for potential impact from injection operations.

- Monitors the added pressure that injection causes in the formation and adjusts the requirements for well operators as needed to be protective. The disposal formations are tested yearly using formation pressure fall-off tests per KDHE regulation K.A.R. 28-46-30. Results are used to determine several injection formation conditions, including pressure anomalies that could indicate the presence of a fault.

California

All Class I injection wells are regulated by the U.S. Environmental Protection Agency Region 9 in California and, therefore, follow federal UIC regulations. California has primacy for Class II wells only. [68]

Louisiana

UIC Class I non-hazardous waste injection wells are regulated under Louisiana Administrative Code (LAC) 43:XVII.101 to 43:XVII.115. Regulations for Class I hazardous waste injection wells are regulated under LAC 43:XVII.201 to 43:XVII.215. [161] Louisiana's underground injection well rules include the federal requirements and the state's more stringent well disposal restrictions, additional permit-by-rule requirements, and facility fees. The Louisiana Department of Natural Resources is responsible for the administration and enforcement. Louisiana prohibits the use of Class I underground injection wells for hazardous waste disposal if the wellhead or any part of the casing is within a body of water. For wetlands, the statute only applies if the site is covered by surface water most of the year. Additionally, if the area is regularly inundated by floodwaters, the statute would apply. [168]

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.[q] 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. [71] 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 ($Length^3/Length^3$)

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

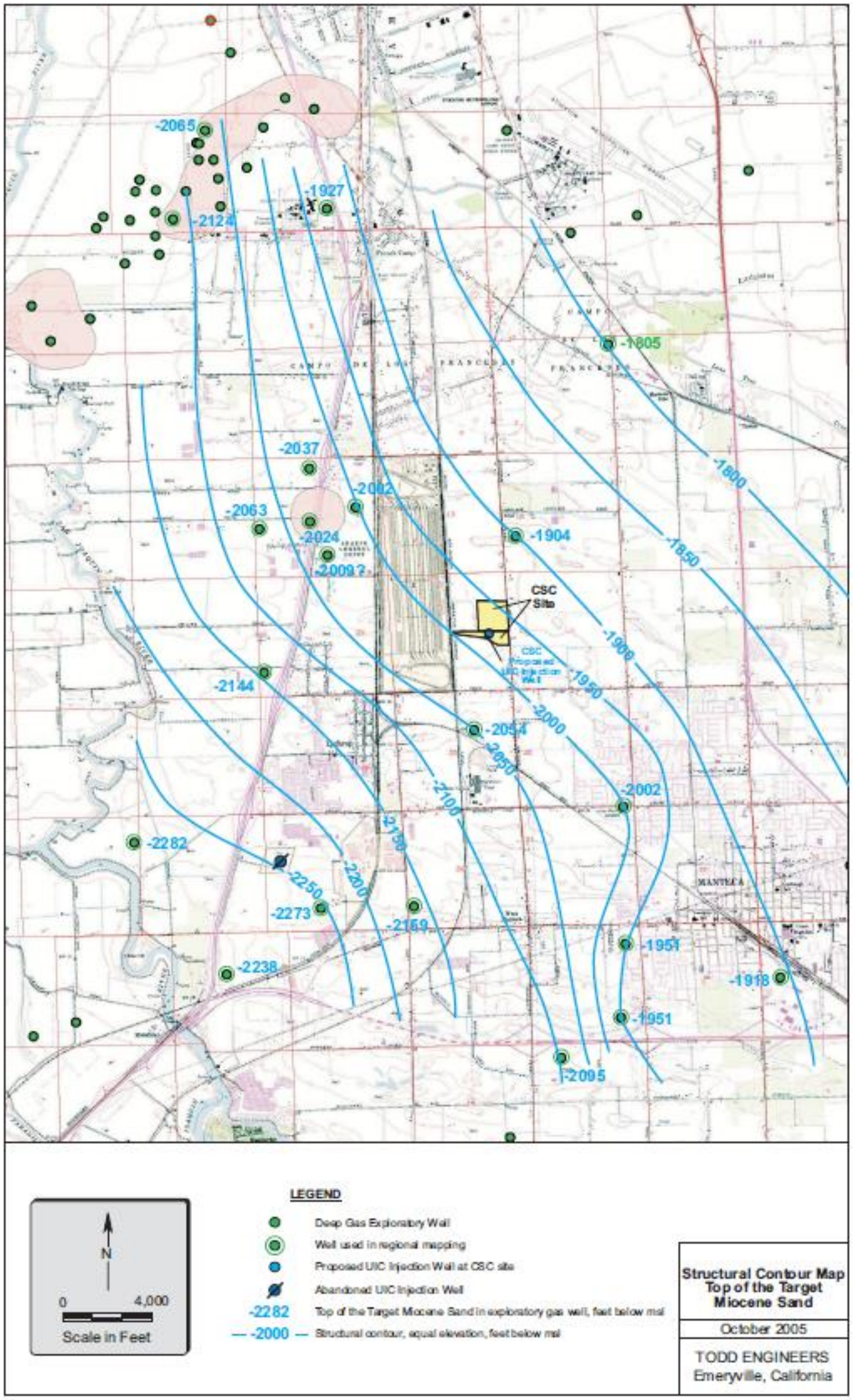
APPENDIX G: EXAMPLE OF FORMATIONAL AREAL EXTENT EVALUATION AT A NON-HAZARDOUS CLASS I WELL SITE

California Specialty Cheese (located in Manteca, California) applied for an Underground Injection Control (UIC) Class I non-hazardous well permit in October of 2005. Wastewater generated at the facility had been discharged to on-site ponds and was later discovered to have impacted local groundwater quality. A newly-designed wastewater improvement process was implemented that included a deep injection well. California Specialty Cheese's permit application outlined plans to construct, test, and operate the Class I injection well at depths below 2,000 feet (ft) with an injection rate of up to 300,000 gallons per day of non-hazardous wastewater from cheese manufacturing. [77]

An evaluation of the subsurface geology of the targeted disposal area yielded two zones as possible injection targets. The main target for injection was a Miocene Sand occurring at a depth of around 2,010 ft near the proposed well location. An alternative target injection zone was also identified in case the Miocene Sand did not meet stated requirements for safe injection. This alternative target is a Cretaceous Sand, referred to as the 2nd Tracy Sand, and occurs at a depth of around 5,235 ft near the proposed well. Both targets appear to have met regulatory requirements for total dissolved solids exceeding 10,000 milligrams per liter, and both targets are protective of underground sources of drinking water with extensive confining layers. [77]

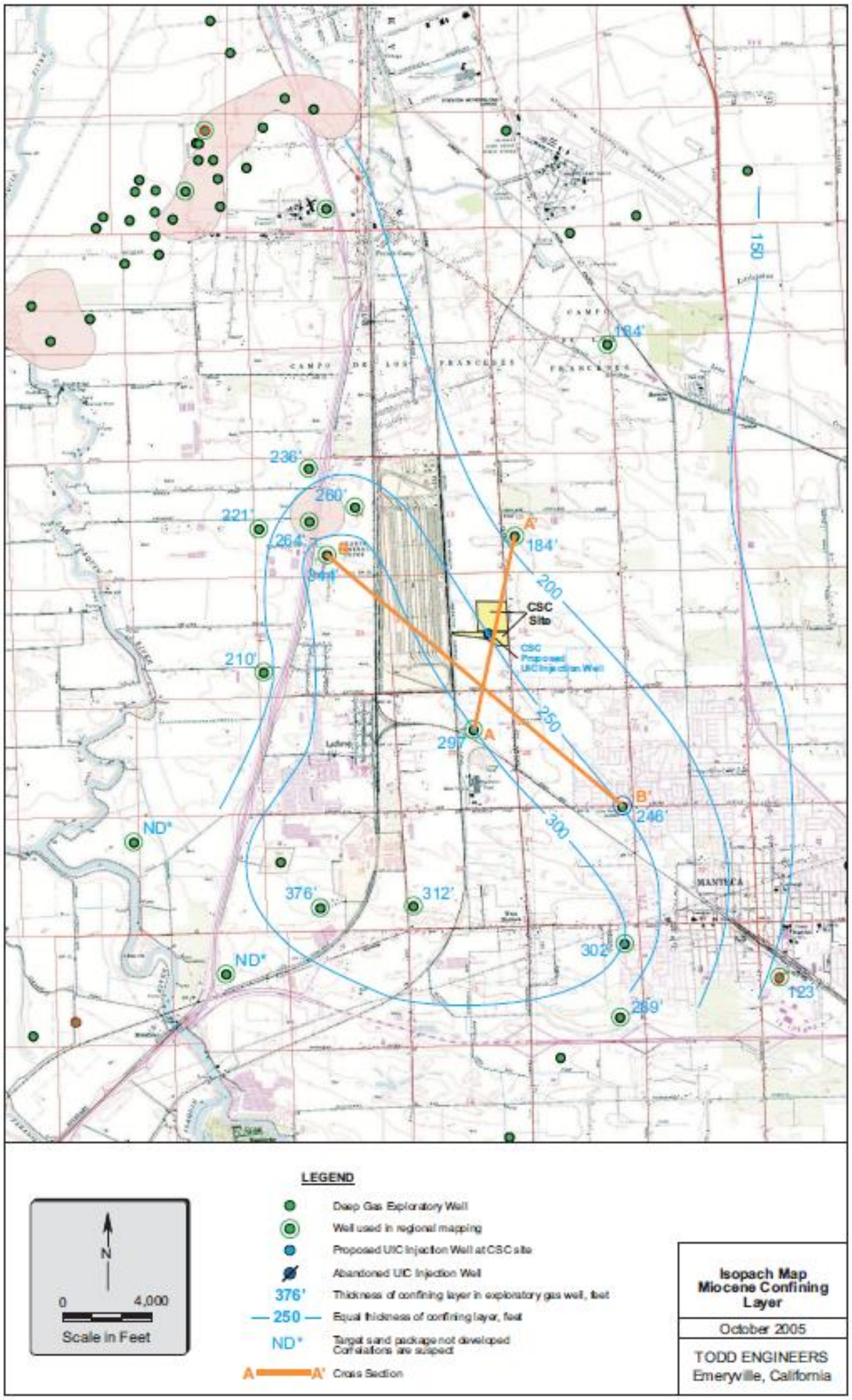
Exhibit G-1 through Exhibit G-5 (extracted from the California Specialty Cheese Class I permit application) demonstrate the integration of existing data (mostly from well logs) to generate cross-sections, formational thickness contours, and infer about formational areal extent of the intended target zones. This example provides a solid basis from which a facility applying for a Class I permit could interpret the subsurface using existing data to confirm critical siting criteria for Class I wells as outlined in Section 4.

Exhibit G-1. Structural contour map of the top of the Miocene Sand target demonstrating formational areal extent



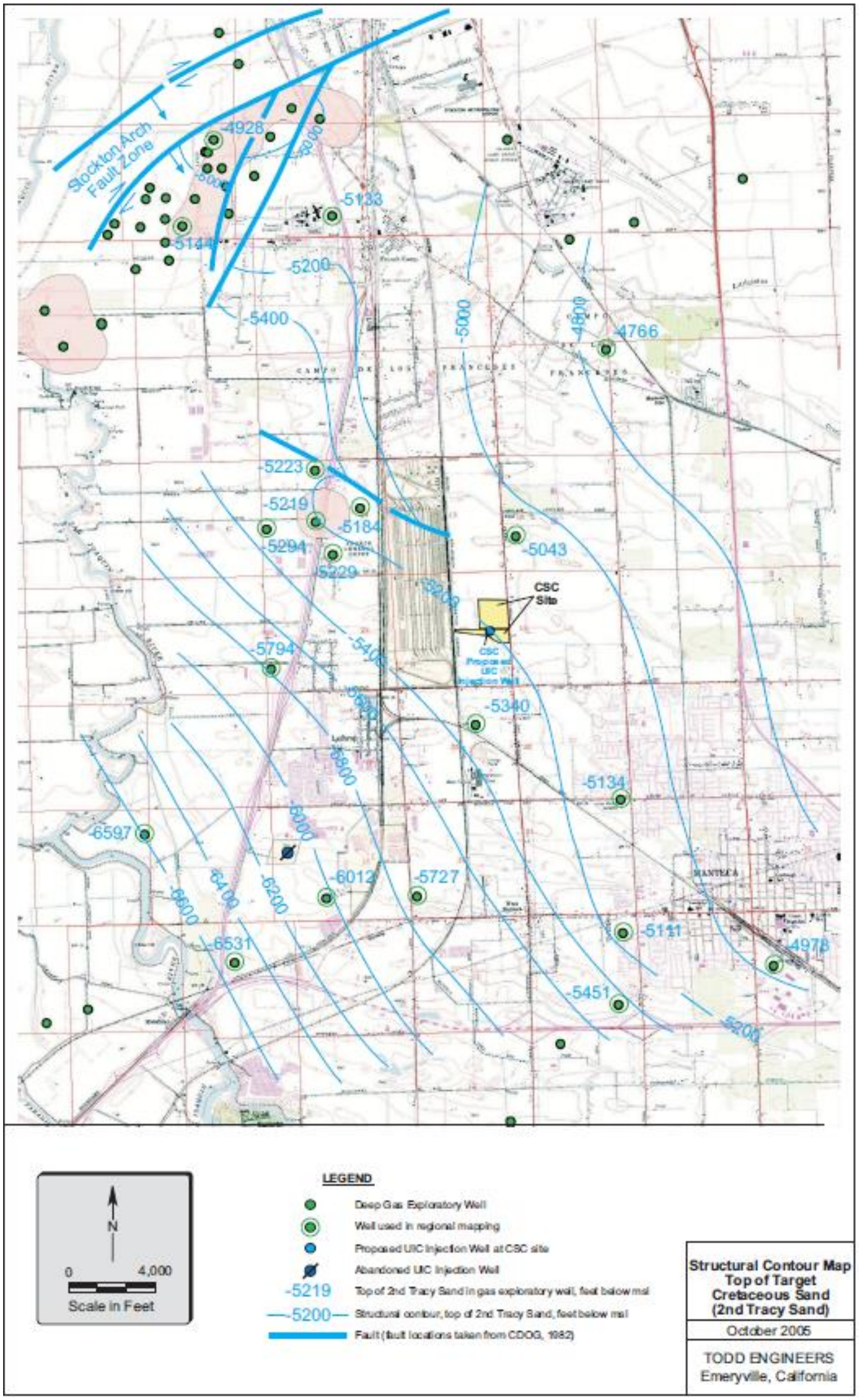
Source: U.S. EPA

Exhibit G-2. Isopach map of the thickness of the Miocene Sand target confining layer demonstrating formational areal extent of the confining zone



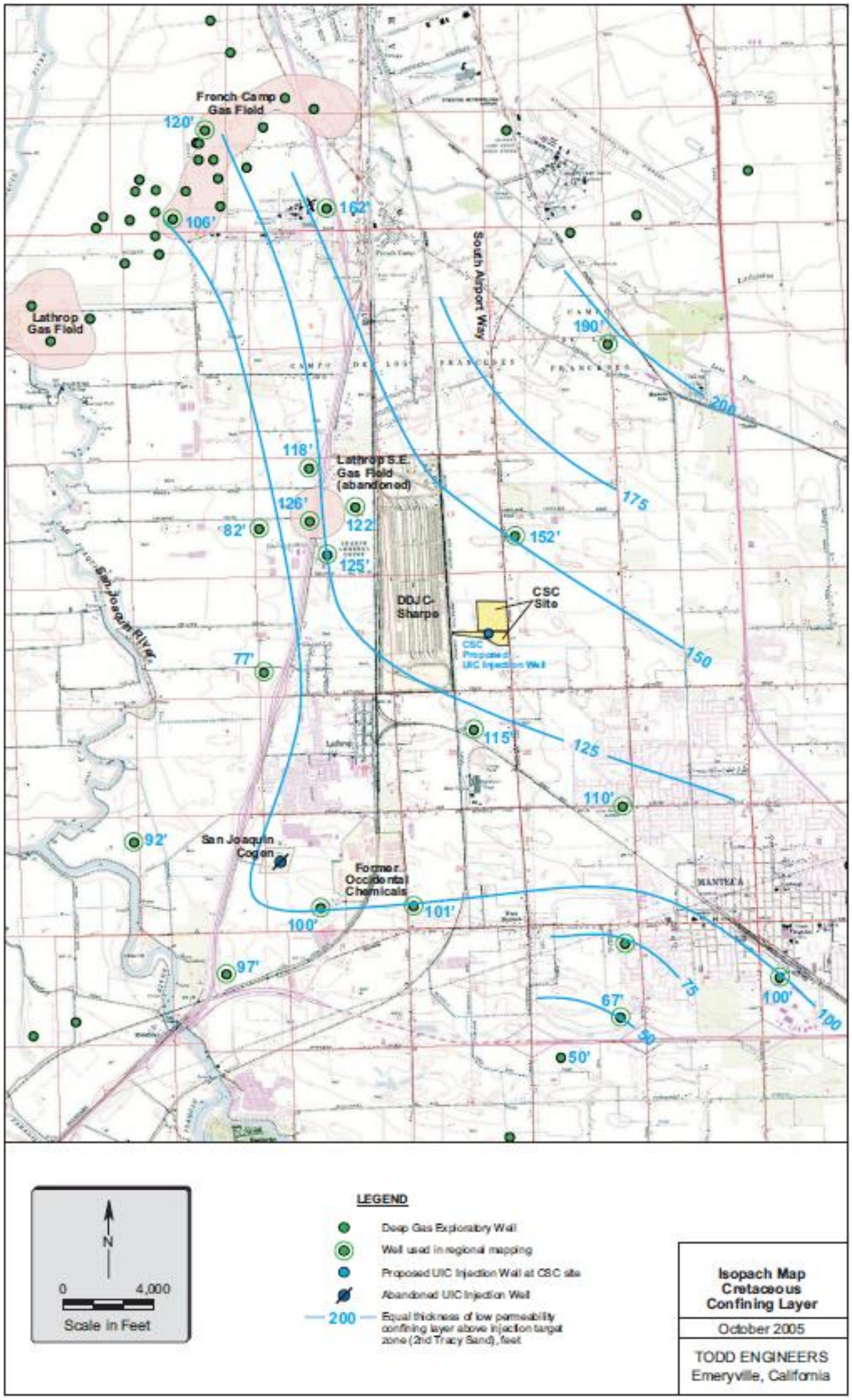
Source: U.S. EPA

Exhibit G-3. Structural contour map of the top of the Cretaceous Sand target demonstrating formational areal extent



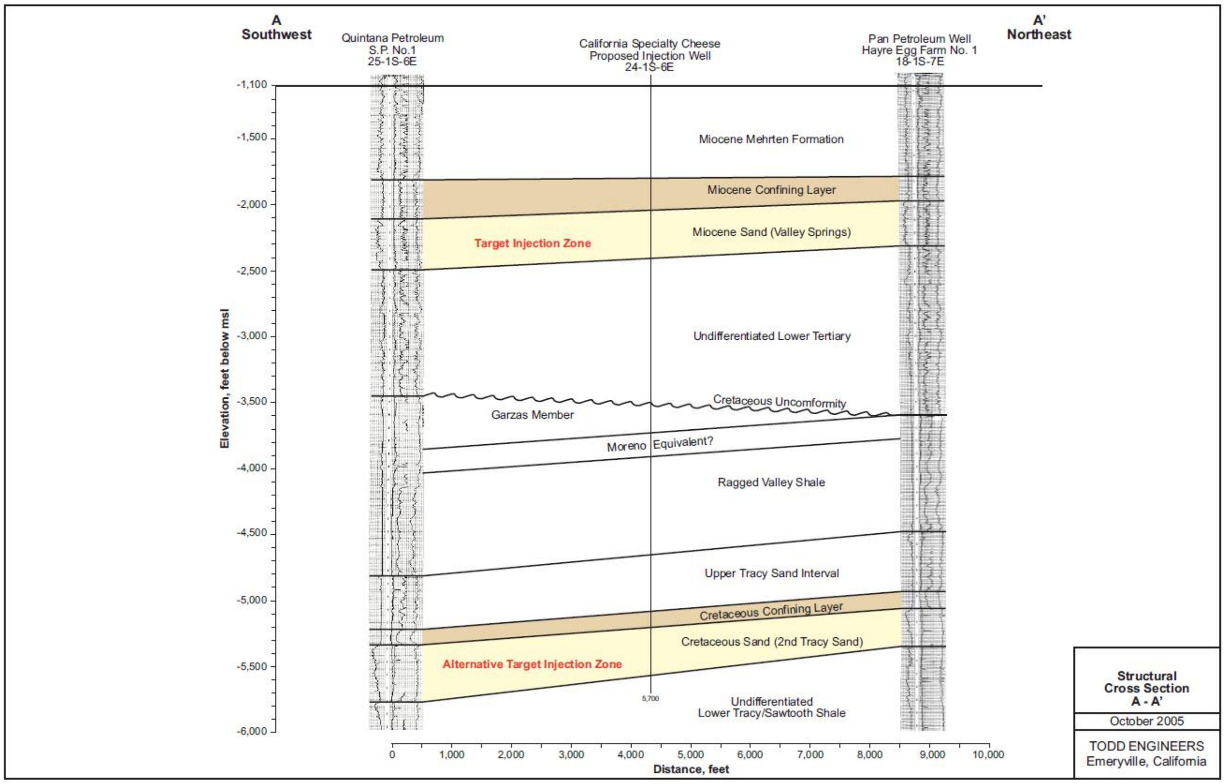
Source: U.S. EPA

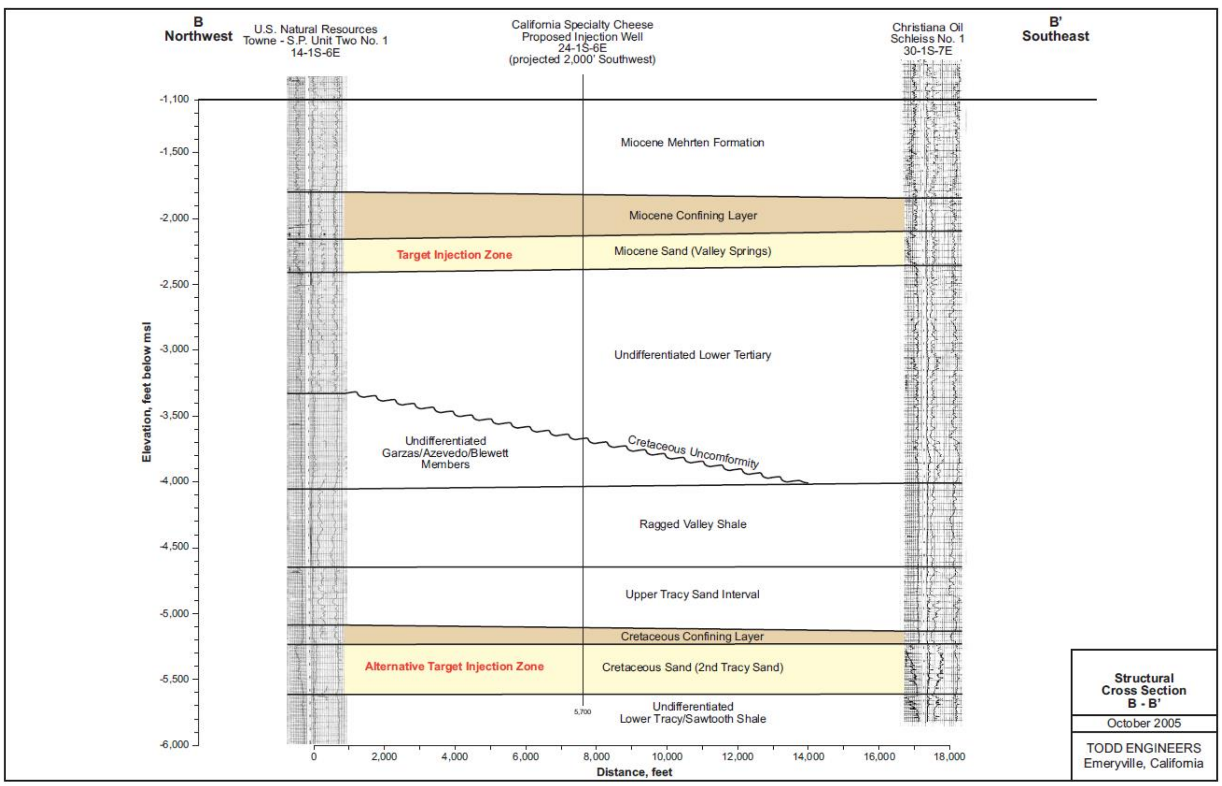
Exhibit G-4. Isopach map of the thickness of the Cretaceous Sand target confining layer demonstrating formational areal extent of the confining zone



Source: U.S. EPA

Exhibit G-5. Cross-sections of the targeted injection zones and confining units generated from well logs





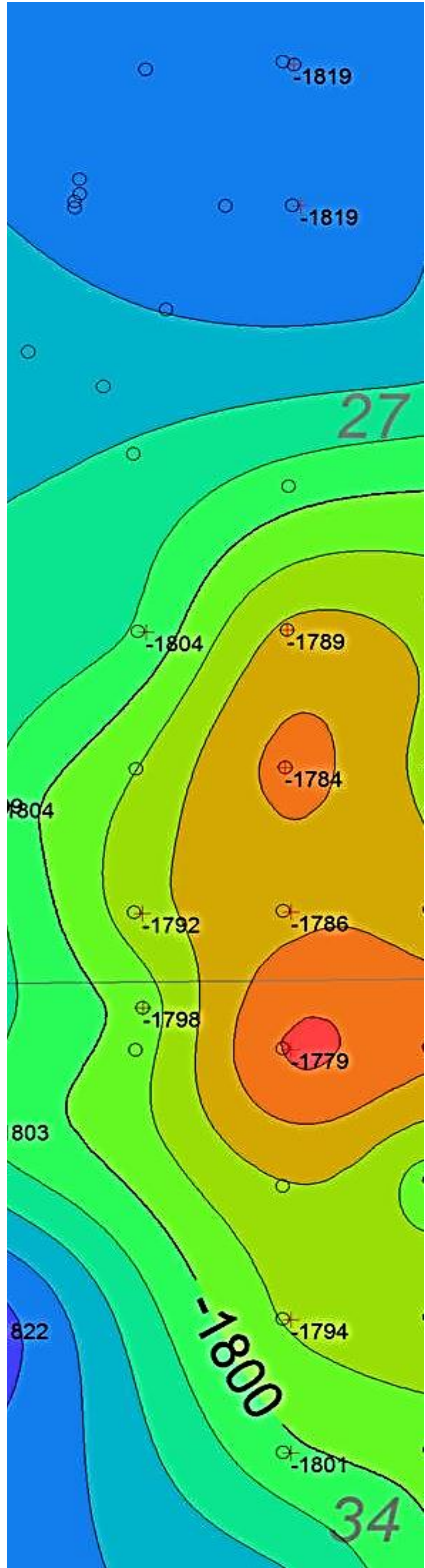
Source: U.S. EPA

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

Exhibit H-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 H-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 M/yr, 1 Mt total	Completed November 2014	[140] [169]
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	[170]
Illinois Industrial Carbon Capture and Storage Project	Decatur, Illinois, United States	Mount Simon Sandstone	7,000 feet	20	26	1 Mt/yr	Active	[171]
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	[171] [172]
Sleipner Project	North Sea, Norway	Utsira Formation	2,297-3,281 feet	24-40	1,000-3,000	0.9 Mt/yr	Active	[171] [172]
Gorgon Storage Project	Onshore Barrow Island, Australia	Dupuy Formation	7,476 feet	22	25-100	3.4-4.0 Mt/yr	Active	[8] [173]
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	[8] [171] [174]
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	[174] [175]
Quest	Alberta, Canada	Basal Cambrian Sand	6,560 feet	16	20-500	1 Mt/yr	Active	[8] [176]
Aquistore	Saskatchewan, Canada	Deadwood and Black Island Formations	11,155 feet	11-17	100-1,000	1,600 tonnes/day	Active	[177] [178]



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