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REVISED FINAL

ENVIRONMENTAL RISK ASSESSMENT
CO2 SEQUESTRATION PROJECTS
ENVIRONMENTAL AND PUBLIC HEALTH RISK
ALLEN PARISH, LOUISIANA

Prepared for

ALLEN PARISH POLICE JURY
Oberlin, Louisiana

Prepared by

GEC

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EXECUTIVE SUMMARY

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Geologic sequestration of carbon dioxide (CO2) is a technology for the long-term, permanent storage of CO2 in deep, porous geologic formations (Ringrose, 2023). The objective of geologic sequestration or geological carbon storage (GCS) is to isolate CO2 derived from anthropogenic emissions from the atmosphere so that the CO2 will not contribute to future potential greenhouse warming of the Earth's climate. The terms Carbon Capture and Storage or CO2 Capture and Storage (CCS) are used to refer to technologies that include capture of CO2 from combustion emissions and industrial processes and the storage or sequestration of the CO2.

The two main types of geologic reservoirs that are most favorable for CO2 sequestration include the saline permeable sedimentary formations and depleted oil and gas reservoirs. Both of these types of reservoirs occur within Allen Parish, Louisiana.

For a sequestered CO2 mass of 100 Mt over the lifetime of a large CO2 sequestration project, the injected CO2 in a 100-foot thick reservoir could take up a volume that extends approximately 6,900 feet (1.3 mile) from the injection point. Saline sand formations in the Gulf Coast can have large potential capacities for storage. Based on ranges of conservative typical sequestration zone property values, it is possible for a suitable storage zone to have storage capacities ranging from 15 to over 100 Mt per square mile of area of the storage zone. Therefore, the Gulf Coast saline aquifer zones could be very effective reservoirs for sequestration of CO2.

Since the 1990s, many CO2 sequestration projects have been proposed worldwide. The planned projects have included pilot projects, demonstration projects, and commercial projects. The Sleipner offshore CO2 sequestration project operated by the Norwegian energy company Equinor (formerly Statoil) is the world's first commercial CO2 sequestration project and has been operated since 1996. The CO2 has remained within the Utsira Formation and has spread northward more than three miles. There have been no releases of CO2 into the near-surface and surface environment from the Sleipner project. CO2 injection has been conducted as part of enhanced oil recovery (EOR) projects since the 1970s and provides additional historical information experience on the injection and movement of CO2 in reservoir zones. The experience from the numerous EOR CO2 flood projects implemented by the energy industry is that the injected CO2 has not affected human health and the environment through releases to underground sources of drinking water (USDWs) or to the ground surface.

Allen Parish is underlain by sedimentary formations of the Gulf Coast sedimentary basin. The base of the Underground Source of Drinking Water (USDW) occurs at depths ranging from 2,500 feet to 3,400 feet. The USDW contains fresh groundwater in the Chicot aquifer at depths to approximately 300 feet and the underlying Evangeline and Jasper aquifers. The Chicot aquifer principally is used for domestic use and irrigation. Municipal and rural water supply is primarily from the Evangeline aquifer at depths of 458 to 974 feet.

Potential sequestration reservoir formations occur between the base of the USDW and the top of overpressured conditions at 11,000 to 15,000 feet depths. Potential sequestration reservoirs could include (from shallowest to deepest) Miocene sand zones, Anahuac Group sand zones, Frio Formation deltaic sands, Cockfield Formation sands, and Wilcox Group sand zones.

On December 28, 2023, the U.S. EPA approved OC's Class VI program for primary enforcement authority (primacy) joining the program with OC's existing UIC primacy Class I-V programs (LDENR, 2023). Following EPA's approval, OC's Commissioner issued on January 9, 2024, notice to all Class VI injection well interested parties informing of the EPA's primacy approval with details regarding EPA Region 6 Class VI permit application OC transmission protocol, additional Louisiana permit application requirements, and other related administrative items (LDENR, 2024). Four noteworthy areas where Louisiana's regulations exceed, thus are more stringent than, the EPA requirements include (1) no waivers will be granted to injection depth requirements, (2) salt cavern CO2 GS is prohibited, (3) multiple well area permits will not be issued, and (4) additional monitoring and operational measures are required (LDENR, 2023).

All well materials must be compatible with fluids that the materials may be expected to come into contact. CO2 is highly corrosive and careful consideration must be taken in the selection of steel alloys and cement used in well construction. Casing and cement or other materials used in the construction of each Class VI well must also have sufficient structural strength and be designed for the life of the geologic sequestration project. Potentially deficient plugged and abandoned oil and gas wells were found in both the northern and southern portions of the parish in this study. The northern half of the parish has far fewer wells than the southern half and thus far fewer deficient wells. The distribution of the wells in the northern part of the parish are configured in such a manner that a CO2 sequestration project may not include a significant number of deficient wells that will be present within the AOR. This is not as probable in the southern half of the parish due to the large number of wells drilled in this area.

The potential risks of concern to Allen Parish include environmental risks to surface water resources, shallow groundwater resources, deep groundwater aquifer resources, and public safety risks associated with exposure of the public to CO2. Project risks associated with CO2 sequestration have been the subject of significant research efforts in the U.S. and internationally (National Energy Technology Laboratory, 2017, Best Practices: Risk Management and Simulation for Geologic Storage Projects, U.S. Department of Energy). The evaluation of project risk is fundamental to the U.S. Environmental Protection Agency (EPA) Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells and the Louisiana Department of Energy and Natural Resources (LDENR) UIC regulations. Project risks for CO2 sequestration can be broadly classified as subsurface storage zone (reservoir) containment risks and risks associated with operations of project surface facilities and transportation of CO2. Subsurface containment is the ability of the reservoir to contain most or all of the injected CO2. The key technical risk is can the CO2 be stored safely in the reservoir so that it is not released to the USDW or to the land surface? Surface and transportation facilities risks include releases of CO2 from pipelines, pumping stations, and well heads. Releases of CO2 from these facilities could be related to operations and accidents. The consequences of releases of CO2 from the storage reservoir or from surface facilities could include impacts to public safety and environmental damages. Exposure of the public to the escape of CO2 from the system could include migration from subsurface containment into aquifers in the USDW or to the land surface including surface water resources and to the atmosphere.

Containment risk events related to leakage through confining zone seal formations and faults have low probability of occurrence based on monitoring conducted during CO2 pilot tests, demonstration projects, and commercial-scale projects and extensive computational modeling of CO2 storage zone processes (see Sections 1 and 3 of this report and reference therein). In addition, the occurrence of multiple overlying confining zones minimizes the potential for CO2 to migrate upward from the sequestration zone to the USDW, fresh groundwater zones, or the near-surface environment. In Allen Parish, faults terminate within the Frio Formation and Anahuac Group, or at greater depths so they do not present potential pathways for CO2 to the USDW. Under the geologic conditions of Allen Parish, any potential movement along a fault, if possible, would likely leave CO2 within the confined zone deeper than the USDW so that the CO2 would remain in the subsurface. In Allen Parish and other areas of Louisiana, the prevalence of high-permeability storage reservoirs for CO2 will allow the injection pressure buildup to be relatively low so that the potential for regional pressurization of the sequestration zone is minimized.

On the other hand, existing wells and well bores can present potential direct pathways for CO2 to move from the sequestration storage reservoir to the USDW or to the near-surface and surface environment. These can include CO2 sequestration project-related wells and other earlier-drilled wells including plugged and abandoned wells.

The surface facilities (pipelines and other surface facilities, such as pumping stations and well heads of CO2 injection wells and project monitoring wells) also can provide a potential for exposure of CO2.

In the traditional oil and gas exploration and production industry including associated produced water injection operations and regulatory protection of USDWs, existing or plugged and abandoned wells are considered to be deficient within an AOR if they lack cement isolation across the base of the USDW to prevent fluid movement into the USDW due to produced water injection operations and/or the lack cement isolation across the top of the injection zone in the well of interest to prevent injected fluids from escaping from the injection zone.

Due to confidential business information (CBI) limitations, additional details of the agency's specific implementation of Corrective Action Plan (CAP) requirements for individual Class VI permit applications under review by LDENR were not available at the time of publication of this report. However, it stands to reason for purposes of risk evaluation, conservatively, considering the age of most wells in Allen Parish, and no apparent reason for operators to complete or plug and abandon past wells with use of CO2 corrosion resistant cement, that most if not all traditional Allen Parish oil and gas E&P well installations within any given Class VI AOR most likely would not have been installed with methods and/or materials considered by the agency to be compatible with the CO2 stream. Should that be the case, it should be noted that deficient cement behind pipe can be remediated by milling out a section of casing and setting a new cement CO2 compatible plug.

In consideration of the DOE research finding, agency CAP compliance considerations, and wells discussion above, CO2 sequestration project environmental and public health risks from wells can be generally categorized and qualitatively ranked from highest (1) to lowest (5) environmental/public health risk below.

1) Wells within AOR Extending Into/Through Injection Zone CO2 Plume.
2) Wells within AOR Extending Into/Through Injection Zone Pressure Front Only.
3) Wells within AOR Above the Injection Zone At or Below Primary Confining Unit.

4) Well within AOR Above Primary Confining Unit At or Below USDW.
5) Wells Nearby Outside of AOR Extending Into/Through Injection Zone.

These five categories are ranked by the qualitative environmental and public health risk potential of each category, respectively, along with respective risks associated with Pipelines further discussed below, in AOR Risk Matrix.

Pipeline transportation and delivery systems for supercritical CO2 appear to be the preferred, if not the only feasible means of transportation and delivery of supercritical CO2 to Class VI injection well facilities proposed in Allen Parish. It is plausible at this time to consider that pipeline systems will remain now and in the foreseeable future the preferred and most feasible means of transporting fluid CO2 material to any other potential Class VI projects in Allen Parish. Accordingly, pipeline transportation and delivery of supercritical CO2 will be an integral key and necessary component of any CO2 Class VI sequestration project in Allen Parish with unique design and operation considerations for protection of public safety, health, and the environment.

Based on review of available published literature on supercritical CO2 pipeline transmission, applicable and relevant PHMSA and LDENR hazardous liquids pipeline transmission regulations, surface and shallow subsurface conditions of Allen Parish, and discussions with industry representatives, GEC summarizes supercritical CO2 pipeline system environmental / public health risks with the general categories and qualitative ranking from highest (1) to lowest (6) listed below.

1) Operator (Human) Error
2) Third-Party Incident
3) Corrosion Induced Equipment Failure
4) Faulty Material / Equipment / Weld Failure
5) Design Flaw
6) Acts of God / Force Majeure / Natural Disasters (Meteorological, Geological, Climatic)

As previously stated above, it is GEC's belief that the LDENR and PHMSA supercritical CO2 pipeline system standards and regulations are adequate when applied and implemented to the fullest extent by the regulated community ensuring safe pipeline installations and supercritical CO2 fluid transmission operations.

Allen Parish has favorable geologic conditions for CO2 sequestration. Potential CO2 sequestration reservoirs between the base of the USDW and the top of overpressured conditions include:

- Miocene sands
- Anahuac Group sands
- Frio Formation sands'
- Cockfield Formation sands
- Wilcox Group sands

The potential depth range for CO_2 sequestration reservoirs is from approximately 3,000 feet to over 14,000 feet in the northern part of Allen Parish to approximately 3,000 feet to 11,000 feet depth in the southern part of Allen Parish.

The regional structure of Allen Parish is relatively simple with generally uniform southward dip of the sedimentary formations and minor occurrence of faulting.

Allen Parish is close to large industrial emitters of CO_2 in southwest and south Louisiana. In addition, the ExxonMobil (formerly Denbury) interstate CO_2 pipeline (Green Pipeline) is located in the southern part of Allen Parish.

Allen Parish has been well-characterized by petroleum exploration that has been conducted for over 100 years. A large number of petroleum test wells has been drilled and the geophysical logs and other data from these wells are available. In addition, two-dimensional seismic surveys have been conducted at close intervals across Allen Parish and several large three-dimensional seismic surveys have been run.

Allen Parish Police Jury informed GEC that CO_2 sequestration projects are being planned in Allen Parish. These include the Magnolia sequestration project planned by Oxy Low Carbon Ventures, LLC and the Hummingbird and Mockingbird CO_2 sequestration projects planned by ExxonMobil Low Carbon Solutions Onshore Storage, LLC. In addition, a Denbury Carbon Solutions LLC (acquired by ExxonMobil in 2024) CO_2 sequestration project has been planned in southern Vernon Parish to the northwest of Allen Parish. This project is called the Draco CO_2 sequestration project.

The development of CO_2 sequestration projects in Allen Parish presents risks and benefits for Allen Parish and its populace. Based on the suitable geologic conditions and proximity to sources of CO_2, the potential for long-term development and operations of CO_2 sequestration projects in Allen Parish could be significant and much larger than the proposed Oxy and ExxonMobil projects.

The economic benefits were evaluated by the H.C. Drew Center for Business and Economic Analysis at McNeese State University for the Oxy Magnolia Sequestration Hub project in November 2024. The McNeese study found that economic benefits included employment labor income, fiscal impacts, and lease payments to landowners. McNeese found that over a 12-year lifetime of the project, over $81 million in labor income would be created in Allen Parish. This would include construction jobs during a 2-year period and operations staff during a 10-year operating period. Real GDP in Allen Parish would increase by approximately $103 million.

The fiscal impact for Allen Parish would include $3.5 million to $4.4 million in tax collections during 2026 through 2035.

In addition, lease payments for surface rights and pore space use have been agreed with landowners. McNeese points out that these payment amounts are confidential but can be assumed to be substantial. These benefits would increase the overall economic and fiscal benefits.

The highest probabilities for releases of CO_2 are related to wells in the subsurface storage reservoir and from supercritical CO_2 pipeline distribution systems. Potential releases from subsurface containment are most likely related to wells that intersect the sequestration zone.

These include oil and gas exploration and production drill holes and wells and CO2-project related injection wells and monitoring wells. The regulatory requirements for identifying wells and implementing remedial actions are comprehensive and significant. It is possible that CO2 sequestration operators will develop projects in areas with fewer existing oil and gas wells in order to minimize this risk and the expense it poses to their projects.

Potential releases from CO2 pipelines can have a range of causes. The supercritical CO2 pipeline standards and regulations are designed to ensure safe pipeline installations and transmission operations, but there is potential for environmental releases.

It is recommended that Allen Parish communicate with the state and with operators to ensure that all regulatory requirements are met for addressing subsurface containment risk and CO2 transmission pipelines. Allen Parish could implement local ordinances to enhance requirements for testing and monitoring, automatic shutoff equipment, and emergency and remedial response to ensure that any potential releases would be minimized and controlled.

TABLE OF CONTENTS

TABLE OF CONTENTS

Executive Summary ES-1
Section 1: Overview of CO2 Sequestration 1
Section 2: Allen Parish Geology 9
Section 3: Louisiana Class VI Well Permit Process And Regulations 15
Section 4: Risk Evaluation Process 45
Section 5: Application to Allen Parish Proposed Projects..66
Section 6: Risk / Benefit Evaluation..69
Section 7: References 71

LIST OF FIGURES

Figure 1-1 Schematic Diagram of Types of CO2 Sequestration Reservoirs....................73
Figure 1-2 Summary of CO2 Trapping Mechanisms..74
Figure 1-3 Capillary Trapping of CO2 in Pore Spaces 75
Figure 1-4 Conceptual Distribution of CO2 Trapping Mechanisms...............................76
Figure 1-5 Estimated CO2 Storage Capacity in the US...77
Figure 1-6 Locations of CO2 Sequestration Projects..78
Figure 2-1 Location of Geologic Cross Section A-A′ 79
Figure 2-2 North-South Geologic Cross Section A-A′ 80
Figure 2-3 Base of USDW in Allen Parish 81
Figure 4-1 Risk Matrix...82
Figure 4-2 Well Risk Categorization 83
Figure 5-1 Locations of CO2 Sequestration Leases, Allen Parish..................................84
Figure 5-2 Allen Parish Area Projects Proposed Sequestration Zones............................85
Figure 5-3 Location of CO2 Pipelines in the US...86
Figure 5-4 Allen Parish Pipelines 87
Figure 5-5 Allen Parish Petroleum Wells...88

APPENDICES

Appendix 1 Class VI Well Applications 1-1
Appendix 2 Environmental Risk Evaluation... 2-1
Appendix 3 Federal Register – Vol. 75, No. 237, Friday, December 10, 2010 3-1

Appendix 4 Federal Register – Vol. 75, No. 237, Friday, December 10, 2010 4-1
Appendix 5 LDENR OC EPA REG Comparison Table 5-1
Appendix 6 Well Construction and Completion 6-1
Appendix 7 Testing and Monitoring 7-1
Appendix 8 Plugging and Abandonment 8-1
Appendix 9 Closure and Post-Closure 9-1

ENVIRONMENTAL RISK ASSESSMENT

Section 1 – Overview of CO_2 Sequestration

Geologic sequestration of carbon dioxide (CO_2) is a technology for the long-term, permanent storage of CO_2 in deep, porous geologic formations (Ringrose, 2023). The objective of geologic sequestration or geological carbon storage (GCS) is to isolate CO_2 derived from anthropogenic emissions from the atmosphere so that the CO_2 will not contribute to future potential greenhouse warming of the Earth's climate. The terms Carbon Capture and Storage or CO_2 Capture and Storage (CCS) are used to refer to technologies that include capture of CO_2 from combustion emissions and industrial processes and the storage or sequestration of the CO_2. Capture processes also include direct air capture (DAC) of CO_2 from the atmosphere. Another important capture technology is the separation of naturally occurring CO_2 from natural gas in gas processing facilities.

The objective of this report is to evaluate the environmental and public health risks that could be associated with CO_2 sequestration projects in Allen Parish, Louisiana. The contents of this report were presented by the GEC project team to the Allen Parish Police Jury in a Special Meeting held on April 28, 2025 at 6:00 P.M. at the Allen Parish Civic Center in Oberlin, Louisiana. The GEC project team consisted of Michael Simms, Ph.D., P.G. (geologist), Gary Snellgrove, M.S. (environmental scientist)), Doyle Johnson, P.E. (petroleum engineer), and Emily Welch, P.G. (geologist).

This section provides an overview of sequestration projects including the physical and geologic setting for sequestration and a history of the use of CO_2 sequestration.

The subsurface reservoir formations that have been identified to be used for geologic sequestration include the following classes:

- Saline permeable sedimentary formations
- Depleted oil and gas reservoirs
- Coal
- Shale formations
- Volcanic rocks

In all of these types of formations, the pore space makes up the potential storage volume. The pore space can consist of open spaces between sand grains, fractures, or microporosity that can occur in shales and coal. **Figure 1-1** summarizes the types of storage reservoirs that can be used.

The two main types of geologic reservoirs that are most favorable for CO_2 sequestration include the saline permeable sedimentary formations and depleted oil and gas reservoirs. Saline permeable sedimentary formations also are referred to as saline aquifers. However, these formations contain pore water that is more saline than drinking water and are deeper than the Underground Source of Drinking Water (USDW) that contains fresh groundwater aquifers. Depleted oil and gas reservoirs generally are deeper than saline aquifers, but are geologically similar. The oil and/or natural gas in the reservoir has been depleted or removed by petroleum production, but small amounts of petroleum can remain trapped in the reservoir. Both of these types of reservoirs occur within Allen Parish, Louisiana.

REQUIREMENTS FOR CO2 SEQUESTRATION

Requirements for effective long-term geological storage of CO2 include sufficient depth, storage volume capacity, reservoir permeability, and overlying containment of the reservoir.

CO2 storage is most efficient if the CO2 is in the liquid or the supercritical fluid state (Niemi and others, 2017). The supercritical state is a dense-gas like state in which the density varies smoothly without phase changes. The supercritical fluid state occurs at pressures greater than approximately 1,074 pounds per square inch (psi). This pressure corresponds to a depth of approximately 2,400 to 2,600 feet below the ground surface. Supercritical CO2 (scCO2) has a density of approximately 500 to 800 kilograms per cubic meter (kg/m^3) under geologic reservoir conditions (Jarrell and others, 2002). This range of density is equivalent to specific gravity values of 0.5 to 0.8 (dimensionless). Having a specific gravity less than one indicates that supercritical CO2 will be buoyant relative to the saline waters in subsurface formations. Supercritical CO2 will tend to rise to the top of the reservoir formation and be trapped by the next overlying lower-permeability rock or sediment layer.

If the reservoir pressure is lower than approximately 1,074 psi because the depth is shallower than 2,400 to 2,600 feet, CO2 will be present in the gas phase and have a much lower density. Therefore, a larger volume of storage reservoir would be needed to store CO2 in the gas phase, assuming that the same mass of CO2 is to be stored. In addition, gas-phase CO2 is much more buoyant than supercritical CO2.

Porosity and permeability of the reservoir zone are important for the storage capacity and ability to inject CO2 into the reservoir. Porosity is the fraction of the reservoir that is occupied by void (pore) spaces between sand grains or fracture openings. In sand formations, the porosity can be between 0.3 and 0.4 (30 to 40%) at moderate depths (Ringrose, 2023). The permeability is the ease of movement of fluids through a porous formation and is related to the interconnectedness of the pore space. In a more-permeable reservoir, the ability to inject (injectivity) is higher and the injected fluid can spread outward from the point of injection.

CONTAINMENT AND TRAPPING MECHANISMS

Because CO2 fluid is buoyant relative to natural formation waters, it is critically important to have vertical overlying containment of the storage reservoir by a low-permeability formation such as clay, shale, or other caprock. The low-permeability caprock is called a seal for the storage reservoir. Containment by an overlying seal layer of lower-permeability sediment or rock is the most significant type of trapping and is called structural trapping or stratigraphic trapping. A structural trap occurs when the top of the storage reservoir is convex upward such as in a dome structure or anticline fold. Separate-phase CO2 fluid will collect in the apex of the structural trap because of buoyancy and not be able to move upward or migrate laterally out of the trap. As the trap is filled with CO2 fluid, the basal level of the CO2 could reach the lowest point of the trapping surface and allow spreading past the spill point of the trap. The geometry of the top of the storage reservoir also can have a trapping configuration based on the sedimentary layering. An example of this is where a sand layer pinches out against clay. This shape of the reservoir top surface can be classified as a stratigraphic trap. **Figure 1-2** summarizes the types of CO2 trapping mechanisms (National Petroleum Council, 2019). Approximately 65 to 70% of the injected CO_2 is estimated to be present as separate-phase CO_2 in structural and stratigraphic geometric trapping configurations (Ringrose, 2023). The proportion of separate-phase CO_2 in the storage zone reservoir is expected to decrease with time as CO_2 trapping subsequently occurs by other mechanisms described below.

CO_2 also can be trapped in the reservoir formation by capillary and residual trapping, solubility trapping, and mineral trapping. Capillary trapping occurs when bubbles and disconnected patches of CO_2 are caught in pores and contact areas between sand grains or in narrow fractures. Because CO_2 is present as a separate fluid material, a residual amount of CO_2 can adhere to the pore walls or be trapped in pore throats between sand grains and not continue to move in the reservoir. Capillary and residual trapping is estimated to be able to hold approximately 20 to 25% of the injected CO_2 within 1 to 10 years after the start of CO_2 injection. **Figure 1-3** shows the distribution of CO_2 and pore water in the pore space of a sand formation.

Solubility trapping or dissolved-phase trapping occurs as the CO_2 dissolves into the native formation water in the reservoir. Solubility trapping could account for 10 to 13% of the injected CO_2 during the first 20 years of a CO_2 sequestration project operating time period (Ringrose, 2023). The amount of solubility trapping is likely to increase over time as the CO_2 stored in the reservoir is in contact with the formation water.

Mineral trapping is the precipitation of carbonate minerals from the dissolved CO_2 and pore water constituents. Geochemical reactions to cause significant mineral trapping are expected to take several thousand years. Mineral trapping is predicted to trap from 1% to 8% of the injected CO_2 over time (Ringrose, 2023). Solubility trapping and mineral trapping are considered the most-effective long-term trapping mechanisms for CO_2 in any type of storage reservoir.

Figure 1-4 shows the conceptual distributions of CO_2 proportions over time in the saline aquifer setting (Ringrose, 2023). After removal by mineral trapping, the remainder of the injected CO_2 stored over long time periods would consist of separate-phase CO_2 in geometric traps (approximately 50%), capillary / residual phase CO_2 (approximately 30%), and dissolved-phase CO_2 (approximately 12%) according to Ringrose (2023).

CO_2 STORAGE CAPACITY

A geologic sequestration project is considered viable if there is sufficient storage capacity together with containment. The planned storage capacity will need to accommodate the amount of CO_2 to be captured and sequestered during the lifetime of the project.

The amount of CO_2 to be sequestered generally is measured in mass of CO_2 in metric tons (tonnes, t). A metric ton is 1000 kilograms or 2204 pounds. Sequestration masses often are referred to in units of one million tonnes (Mt).

A metric ton of CO_2, when in the supercritical fluid state, takes up a volume of approximately 52.6 cubic feet. This is a cubic volume of CO_2 approximately 3.75 feet on each side. In a subsurface reservoir, the supercritical CO_2 occupies only the pore space so it will spread out into a slightly larger volume of space. For a sand with porosity of 0.35 (35%), the total volume of reservoir occupied by 1 metric ton of supercritical CO_2 is approximately 150.3 cubic feet. This is a cubic volume of reservoir that is approximately 5.3 feet on each side. To get an understanding of the capacity of a 100-foot thick saline sand reservoir formation, one million metric tons (1 Mt) would occupy a volume of the reservoir that would extend outward approximately 690 feet radially from the injection point. This would be a circular area approximately 1,380 feet in diameter, which is approximately one quarter of a mile. For a sequestered CO2 mass of 100 Mt over the lifetime of a large CO2 sequestration project, the injected CO2 in a 100-foot thick reservoir could take up a volume that extends approximately 6,900 feet (1.3 mile) from the injection point. The following paragraphs provide a more-detailed technical discussion of how CO2 storage capacity is evaluated.

Volumetric analysis (U.S. DOE, 2012) is used to estimate the CO2 storage capacity of a sequestration storage zone. The CO2 storage capacity is the mass of CO2 that can be stored in a reservoir zone based on the reservoir-zone volume and physical properties such as porosity and pore-water saturation. The theoretical storage capacity is the amount of CO2 that can displace the pore water leaving pore water only at the irreducible water saturation (Swirr). The theoretical storage capacity is given by

$$G = V\ \emptyset \rho (1 - Swirr)$$

where G is the mass of CO2, V is the reservoir volume, ø is the porosity, and ρ is the density of the CO2 phase. The theoretical storage capacity is the maximum storage capacity and can be achieved in a structural or stratigraphic trap configuration in which the CO2 is constrained to occupy the volume of the trap and fill all available pore space except the pore space occupied by irreducible formation water saturation. In this formulation, volume V is the volume of the storage zone within the trapping region. It is calculated by multiplying the storage zone area by the net thickness of the saline sand permeable intervals. The net thickness of the sand zones is calculated from the total storage complex thickness multiplied by the net sand-to-gross thickness ratio (N/G).

CO2 storage in flat-lying and dipping reservoir zones is affected by fluid dynamic effects including residual CO2-phase saturation and buoyant transport so that the CO2 fills only a fraction of the available pore space as the CO2 plume expands and moves in the reservoir. The effective storage capacity accounts for these effects with a storage efficiency factor ε as follows:

$$G = V\ \emptyset \rho \varepsilon (1 - Swirr)$$

The storage efficiency factor can vary from values ranging from values much less than 1 (residual saturation) to close to 1 depending on the degree of structural trapping.

Saline sand formations in the Gulf Coast can have large potential capacities for storage. Conservative example values of the parameters used in the estimates of CO2 capacity are listed in the following table:

Parameter	Typical Value
Storage Zone Thickness	Hundreds of feet to 2,000 feet

Net-to-Gross (N/G) Ratio (sand thickness to total storage zone thickness)	40 to 60%
Porosity (pore volume to total volume)	0.35 to 0.38 (35 to 38 %)
Density of Supercritical CO2	43.6 pounds/cubic foot at specific gravity of 0.7
Irreducible Water Saturation	0.2 (20%)
Storage Efficiency Factor	0.08 (residual trapping) to 1.0 (structural trapping)

Based on these ranges of conservative typical values, it is possible for a suitable storage zone to have storage capacities ranging from 15 to over 100 Mt per square mile of area of the storage zone. Therefore, the Gulf Coast saline aquifer zones could be very effective reservoirs for sequestration of CO2. **Figure 1-5** shows estimated CO2 storage capacity in the U.S. and that the Gulf Coast region has the highest storage capacities and CO2 injectivity in the U.S. (National Petroleum Council, 2019).

Allen Parish is located within the Gulf Coast and contains numerous saline aquifers that could be used as CO2 storage zones as described in Section 2 of this report. Based on the CO2 storage estimates listed above, the 766-square mile area of Allen Parish could support the subsurface sequestration of on the order of 11,000 Mt to 76,000 Mt of CO2.

HISTORY OF CO2 SEQUESTRATION PROJECTS

Since the 1990s, many CO2 sequestration projects have been proposed worldwide. The planned projects have included pilot projects, demonstration projects, and commercial projects. The commercial projects and the pilot and demonstration projects have provided information on geologic characterization needs, evaluation of storage capacity, monitoring of CO2 injection conditions of pressure and injection rate, monitoring of CO2 in the reservoir, accounting of injected CO2, and environmental monitoring of the subsurface, groundwater aquifers, and near-surface environments.

Pilot projects usually are smaller than 10,000 t (0.01 Mt) and have short durations of operation. Examples of pilot projects have included the Frio pilot projects near Dayton, Texas conducted between 2004 and 2007 and the SECARB Cranfield, Mississippi project conducted in 2008 (Jia and McPherson, 2019). The Otway Basin Project in Australia is another well-known pilot project that was conducted in 2011 (Cook, 2014).

Demonstration projects are considered to inject CO2 at rates between 0.001 and 1 Mt per year for at least several years. The Illinois Basin-Decatur Project was conducted at the Archer Daniels Midland Company (ADM) ethanol plant in Decatur, Illinois from 2011 to 2014 and injected approximately 1 Mt of CO2 (Bauer and others, 2019). The Illinois Basin project included the first permits for long-term underground injection of CO2 that have been granted by the U.S. Environmental Protection Agency is the United States. The SECARB Citronelle, Alabama project also was a significant demonstration project.

Commercial-scale sequestration projects are considered to inject on the order of 1 Mt per year for long-term periods of time. Commercial projects include the Sleipner and Snohvit projects in the Norwegian North Sea, the In Salah project in Algeria, and the Quest project in Alberta, Canada.

Figure 1-6 shows the locations of CO2 sequestration pilot projects and commercial-scale projects in the world (Gale and Wilson, 2019).

The Sleipner offshore CO2 sequestration project is operated by the Norwegian energy company Equinor (formerly Statoil) approximately 150 miles off the coast of Norway on the Norwegian continental shelf (Eiken, 2019; Ringrose, 2023). This is the world's first commercial CO2 sequestration project. Injection of CO2 started in 1996 and has continued since that time at a rate of approximately 1 Mt per year. The source of the CO2 is natural gas produced from the Sleipner West field in the North Sea. The CO2 is separated from the natural gas and transported by pipeline to the Sleipner East field. The water depth at the injection platform is approximately 260 feet and the storage reservoir is the Utsira Formation at a depth of approximately 3,300 feet below sea level. The Utsira Formation consists of approximately 980 feet of unconsolidated sand containing thin mud layers. The Utsira Formation sand has a porosity of 35 to 40% and permeabilities of 1,000 to 8,000 millidarcies (md). The Sleipner project was incentivized by the Norwegian state tax on offshore CO2 emissions and has been expanded to include CO2 from the Gudrun Field since 2014. During the operating period, Equinor has pioneered geophysical monitoring technologies to characterize the injection and storage process and these results have guided the development of CO2 sequestration project plans and government regulations. Three-dimensional seismic surveys have been conducted by Equinor at 1- to 2-year intervals to monitor the spreading of the CO2 in the storage reservoir. The seismic monitoring shows that the CO2 has spread in numerous layers trapped by the thin mud layers within the reservoir. The CO2 has remained within the Utsira Formation and has spread northward more than three miles. There have been no releases of CO2 into the near-surface and surface environment from the Sleipner project.

Equinor also has conducted the Snohvit CO2 sequestration project located in the Norwegian sector of the Barents Sea north of Norway (Gude and Landro, 2019). The CO2 injection was started in May 2008 and has averaged 0.75 Mt per year. The CO2 is separated from natural gas at a liquefied natural gas (LNG) plant and transported by pipeline to the injection site. The injection was into the Tubaen Formation at a depth of 8,700 feet below sea level from 2008 to 2011. Equinor changed the injection zone to the Sto Formation in 2011 after pressure buildup in the Tubaen Formation caused decreased injectivity. Ongoing seismic monitoring of the Snohvit project has been able to track the spreading of CO2 in the storage reservoir. The injected CO2 has been contained in the reservoir and has not been released to the environment.

British Petroleum (BP) conducted the In Salah, Algeria CO2 sequestration project from 2004 to 2011. During this period, 3.8 Mt of CO2 were injected into the reservoir zone in the Krechba anticlinal structure. For this project, the storage reservoir was concluded to be too thin, and the CO2 injection was discontinued after surface uplift of 30 mm was observed with interferometric satellite airborne radar (InSAR) monitoring.

Shell Canada Limited has conducted the Quest CO2 sequestration project north of Edmonton, Alberta, Canada since 2015 (Jia and McPherson, 2019). This project has used three injection wells to sequester CO2 from oil sands operations in a Precambrian storage reservoir at a depth of 7,000 feet below ground surface. Approximately 1.2 Mt of CO2 has been injected per year. The Quest includes extensive monitoring of the subsurface with three deep monitoring wells (5,400 to 5,600 feet deep) and nine shallower monitoring in the groundwater aquifer zone (65 to 650 feet deep). The extent of the CO2 in the storage reservoir also has been monitored with two-dimensional vertical seismic profiling (VSP) and three-dimensional seismic surveys. The CO2 has been contained in the storage reservoir and there have been no releases to the hydrosphere (Shell, 2024). Shell has announced plans for expansion of the CO2 sequestration in the area with the Polaris CO2 sequestration project to sequester more than 10 Mt of CO2 per year.

ENHANCED OIL RECOVERY CO2 FLOODING

CO2 injection has been conducted as part of enhanced oil recovery (EOR) projects since the 1970s and provides additional historical information experience on the injection and movement of CO2 in reservoir zones. In the U.S., the most active CO2 flooding areas are the Permian Basin of West Texas and eastern New Mexico. Other areas of active CO2 floods include the Rocky Mountain Basin, southeastern Texas, southern Louisiana, and southern Mississippi. The CO2 for EOR projects is derived from natural sources such as LaBarge-Big Piney in Wyoming, the Bravo Dome in New Mexico, McElmo Dome in Colorado, and Jackson Dome in Mississippi and from industrial sources such as ammonia plants (Jarrell and others, 2002).

As CO2 flooding projects expanded in the 1990s, it was suggested that CO2 sequestration projects be conducted as part of EOR projects. This approach was taken by the Weyburn-Midale project in southeastern Sakatchewan, Canada. The EOR CO2 flood project started in 1992. The CO2 Monitoring and Storage project began in 2000 and sequestered 21 Mt of CO2 in the Midale reservoir by the end of 2011 (Niemi and others, 2017). The CO2 is derived from the gasification of lignite coal at the Dakota Gasification synthetic fuel plant in Beulah, North Dakota and is transported to Weyburn by pipeline. Extensive geochemical and geophysical monitoring of the project has shown no pressure buildup or migration of CO2 from the reservoir (Maxwell, 2019).

The experience from the numerous EOR CO2 flood projects implemented by the energy industry is that the injected CO2 has not affected human health and the environment through releases to underground sources of drinking water (USDWs) or to the ground surface.

REPORT OUTLINE

Section 2 of this report summarizes the geologic conditions of Allen Parish including the subsurface stratigraphy and structure, the depth of the USDW, and the occurrence of groundwater.

Section 3 summarizes the Federal (U.S. Environmental Protection Agency) and Louisiana Department of Energy and Natural Resources (LDENR) permitting requirements for CO2 sequestration for Class VI of the Underground Injection Control (UIC) program. This includes the regulatory requirements for site characterization, prediction of the CO2 plume movement, corrective action for deficient wells in the project area, monitoring and testing, and emergency response.

Section 4 presents the risk evaluation process for CO2 sequestration projects. This includes evaluation of risks affecting containment in the storage reservoir and risks associated with sequestration operations and CO2 transportation.

Section 5 applies the risk evaluation to CO2 sequestration projects that could be planned for Allen Parish. These include projects being proposed by Oxy Low Carbon Ventures, LLC and by ExxonMobil Low Carbon Solutions Onshore Storage, LLC.

Section 6 compares risks of CO2 sequestration and project benefits.

Section 7 lists the technical references cited in this report.

SECTION 2 – Allen Parish Geology

In Allen Parish and adjacent areas of southwestern Louisiana, interbedded continental and marine deposits form a southeastward-thickening wedge of unconsolidated sediments ranging from late Tertiary to Pleistocene in age (Whitfield, 1975). The shallow portions of this sequence contains the Underground Source of Drinking Water (USDW), which has pore water with total dissolved solids (TDS) content of less than 10,000 mg/L. The fresh-water-bearing aquifers occur within the USDW zone.

This section describes the geology and stratigraphic framework of Allen Parish based on published regional cross sections, geologic reports, geophysical well logs in the parish from the LDENR Strategic Online Natural Resources Information System (SONRIS), and regional geologic and hydrogeologic summaries.

GEC has constructed a geologic cross section from north to south through Allen Parish to illustrate the principal subsurface geologic zones. This cross section is representative of the geologic conditions in Allen Parish. **Figure 2-1** shows the location of the geologic cross section. **Figure 2-2** shows the geologic cross section including formations to depths of approximately 15,000 feet below sea level. The geologic cross section shows the base of the USDW, the main geologic formation boundaries, and the top of the overpressure zone. A Well Summary Table including the geophysical well log's operator name, well name and number, serial number, status, total depth, ground level elevation, and Kelly bushing elevation is included as **Table 2-1**.

The subsurface stratigraphy is discussed below in descending order from the ground surface.

PLEISTOCENE FORMATIONS

The Pleistocene consists of terrace deposits at the land surface and the underlying sands of the Chicot aquifer. In northern Allen Parish, the terrace deposits generally are less than 50 feet thick. The terrace deposits thicken southward to up to 100 feet in thickness. The Chicot aquifer in Allen Parish consists primarily of massive sand that ranges from 100 feet thick in the northern part of the parish to over 300 feet in the southern part of Allen Parish. In this area, the sand units of the Chicot aquifer are undifferentiated (Lindaman, 2023).

PLIOCENE FORMATIONS

The top of the Pliocene occurs at depths of 150 to 200 feet below ground surface (bgs). The Pliocene formations consist of the upper part of the Evangeline aquifer. This portion of the Evangeline aquifer is known as the Foley Formation (Whitfield, 1975) and consists of sand interbedded with clay.

MIOCENE FORMATIONS

The Miocene in Allen Parish consists of sand and clay of the Fleming Formation (Hinds, 1999). The top of the Fleming Formation occurs at depths of approximately 1,000 to over 2,000 feet bgs. The Fleming Formation includes six members and makes up the lower part of the Evangeline aquifer and the underlying Jasper aquifer. The members include from the base upward the Lena Member, Carnahan Bayou Member, Dough Hills Member, Williamson Creek Member, Castor Creek

Member, and Blounts Creek Member. The six members are lithologically heterogeneous but alternate between relatively finer or coarser grained sand bulk compositions that are thought to reflect deposition in either brackish water or fluvial environments, or more specifically in lower or upper coastal plain environments, respectively (Hinds, 1999). The sands are interbedded with thick, continuous clay layers. The base of the Miocene ranges from 3,900 feet bgs in the northern part of Allen Parish to approximately 6,000 feet bgs in the southern part of Allen Parish. The total thickness of the Miocene in Allen Parish is 2,500 to greater than 3,000 feet.

ANAHUAC GROUP

The Anahuac Group of Oligocene age underlies the Miocene deposits. The top of the Anahuac Group occurs at approximately 3,900 to 6,000 feet bgs. The Anahuac Group consists of clay interbedded with proximal deltaic sand deposits. The Anahuac Group is a basal confining zone for the Miocene sands and an upper confining zone for the underlying Frio Formation sands. The Anahuac Group was deposited during a major transgressive phase of sedimentation in south Louisiana. The Anahuac Group is 300 to 750 feet thick.

FRIO FORMATION

The top of the Frio Formation of Oligocene age occurs at approximately 4,200 to 6,700 feet bgs. The Frio Formation is included in the Catahoula Group. The Frio Formation consists of clay interbedded with deltaic sand deposits. The Frio Formation ranges from over 1,200 feet thick to approximately 2,000 feet thick. The base of the Frio is identified as the base of the deepest deltaic sand zone that occurs at any given location and ranges from 5,450 feet bgs to approximately 9,400 feet bgs.

VICKSBURG AND JACKSON GROUPS

The Vicksburg and Jackson Groups consist of geographically widespread clay deposited during a major transgression. This sequence of clay is over 1,000 feet thick in Allen Parish. The Vicksburg/Jackson Groups form a regional seal underlying the Frio Formation and overlying the deeper sand formations such as the Cockfield Formation and Wilcox Group.

COCKFIELD FORMATION

The top of the Cockfield Formation of Eocene age occurs at approximately 5,700 to 9,500 feet bgs and the formation consists of lenticular beds of fine sand and clay. The Cockfield Formation has contained oil and gas fields in Allen Parish. The Cockfield Formation is 1,000 to 1,200 feet thick. The Cockfield Formation in underlain by clay formations.

WILCOX GROUP

The top of the Wilcox Group of Eocene and Paleocene age occurs at approximately 8,400 to 12,400 feet bgs. The Wilcox Group consists of 3,500 to 4,000 feet of interbedded sand and clay. The Wilcox shallow marine sands have been a target of petroleum exploration in Allen Parish. The Wilcox Group is underlain by the Midway Group clay, which occurs at the base of the Cenozoic age section.

The underlying Mesozoic section of Gulf Coast sedimentary formations is not addressed in this report because they are not suitable for CO2 sequestration in this area due to their great depth and overpressured pore fluid conditions.

GROUNDWATER AQUIFERS AND BASE OF THE UNDERGROUND SOURCE OF DRINKING WATER

The primary groundwater resources of Allen Parish, from surface to deepest, include the Chicot aquifer system, Evangeline aquifer, and the Jasper aquifer system. Groundwater in the Chicot aquifer, Evangeline-equivalent aquifers, and Jasper-equivalent aquifers is part of a regional groundwater-flow system known as the Southern Hills regional aquifer system (Griffith, 2003) or the Coastal Lowlands aquifer system (Lindaman, 2023). Regional groundwater flow in the aquifer system is driven by topographic differences between higher-elevation source areas in central Louisiana and the lower elevations of the Mississippi River valley and coastal areas of Louisiana.

The Coastal Lowlands aquifer system is predominantly composed of sands and clays arranged in complex assemblages (Lindaman, 2023). The thickness of beds can change abruptly, with sands ranging from thin beds to stacked channel deposits that are hundreds of feet thick (Lindaman, 2023).

The Evangeline aquifer of Pliocene and Miocene age and the Jasper aquifer of Miocene age are part of a complex of continental and marine sediments deposited progressively gulfward on the continental shelf of the Gulf of Mexico (Whitfield, 1975). The Evangeline and Jasper aquifer are separated by the Burkeville confining beds of the Castor Creek Member of the Miocene Fleming Formation. Sand units within the Evangeline and Jasper aquifer are separated by varying clay beds, which restrict vertical movement.

CHICOT AQUIFER

The Chicot aquifer of Pleistocene age serves as the primary source of fresh groundwater in southwestern Louisiana and was designated as a Sole Source Aquifer (SSA) by the U.S. Environmental Protection Agency in 1988. An SSA is defined as an aquifer that supplies at least 50% of the drinking water for its service area and there are no reasonably available alternative drinking water sources should the aquifer become contaminated (US EPA, 2024). The Chicot aquifer consists of alternating beds of unconsolidated gravel, sand, silt, and clay (Lovelace, 1999). The sediments, deposited in deltaic and near-shore marine environments, form beds that dip and thicken southward beneath the Gulf of Mexico (Lovelace, 1999).

Within northern Allen Parish, the dip of the base of the aquifer system flattens, but its thickness becomes more irregular, owing to the irregular surface that the deposits were laid down upon and subsequent erosion of the ground surface by rivers and streams.

Groundwater in the Chicot aquifer generally flows south and southeastward from the northern part of Allen Parish (Lindaman, 2023) towards areas of lower land surface elevation and areas of greater groundwater use. The areas of maximum use of groundwater from the Chicot aquifer are located to the southeast in Evangeline and Acadia Parishes. Chicot aquifer groundwater in the eastern portions of Allen Parish has a southeastward direction of flow towards the cone of depression centered in Acadia Parish (Lovelace and others, 2002).

EVANGELINE AQUIFER

The Evangeline aquifer of Pliocene and Miocene age primarily consists of a deltaic sequence of fine to medium sand interbedded with silt, soft to moderately hard greenish-gray laminated clay, and local beds of coarse sand (Whitfield, 1975). Sands within the Evangeline are separated by fairly extensive clays; however, the sands are interconnected sufficiently so that they function regionally as one aquifer (Whitfield, 1975). Water from this aquifer is mostly a sodium bicarbonate type, soft, alkaline, and low in iron concentration (Whitfield, 1975).

The maximum thickness of Evangeline sands containing fresh water occurs in southern Allen and Evangeline Parishes, where thicknesses reach 1,000 feet (Whitfield, 1975).

JASPER AQUIFER

The Jasper aquifer of Miocene age consists of deltaic and marine sediments of generally well sorted, very fine to medium sands interbedded with greenish-gray clays; light-gray sands with occasional traces of black, granule-size gravel make up approximately 50% of the aquifer (Whitfield, 1975). Individual sand beds are typically less than 50 feet thick but some sand beds exceed 100 feet. In the upper part of the Jasper aquifer, beds of lignite are interbedded with the sand and clay. Similarly to the Evangeline aquifer, water in the upper part of the Jasper aquifer is a soft, sodium bicarbonate type (Whitfield, 1975). Water from sands in the lower part of the Jasper aquifer tends to contain a lower concentration of iron.

The maximum depth to the top of the Jasper aquifer is approximately 2,600 feet below sea level in southwestern Allen Parish, where only the uppermost sands of the aquifer contain fresh water (Whitfield, 1975).

The Jasper aquifer system consists of the Williamson Creek aquifer, the Dough Hills confining unit, and the Carnahan Bayou aquifer (Lindaman, 2023).

GROUNDWATER QUALITY

The Chicot aquifer system and Evangeline aquifer contain freshwater throughout Allen Parish. The Jasper aquifer system contains freshwater in the northwestern half of the parish and saltwater (water with chloride concentrations greater than 250 milligrams per liter [mg/L]) in the southeastern half (Prakken and others, 2012).

The base of the fresh groundwater generally ranges from 1,500 to 3,500 feet below sea level in the northwestern half of the parish and from about 1,500 to 2,200 feet below sea level in the southeastern half of the parish (Prakken and others, 2012).

Recharge to aquifers in the parish is from rainfall, leakage from overlying aquifers, and seasonally from rivers. The Chicot aquifer is recharged throughout Allen Parish with the exception of lower-elevation areas in the southeastern part of the parish near Bayou Nezpique, Castor Creek, and Caney Creek (Nyman, 1984). The Evangeline and Jasper aquifers are recharged in higher-elevation areas in the northern part of Allen Parish. The Jasper and Evangeline aquifers typically have higher hydraulic heads than the Chicot aquifer so can discharge upward into the Chicot aquifer. The discharge from the aquifers is by natural flow into rivers, leakage into underlying aquifers, and withdrawals from wells (Prakken, and others, 2012).

State well-registration records (LDENR Strategic Online Natural Resources Information System or SONRIS) include 1,000 registered water wells and test boreholes in Allen Parish in January 2025. Of these registered wells, 419 have been plugged and abandoned or otherwise out of service. There are approximately 550 active wells in Allen Parish including 216 domestic wells and 186 irrigation wells. All but one of the domestic wells are installed in the Chicot aquifer and one domestic well is installed in the Evangeline aquifer. The domestic wells predominantly are installed in the upper part of the Chicot aquifer with 87% at depths of less than 150 feet bgs. The irrigation wells predominantly are installed in the Chicot aquifer with 97% of the irrigation wells being less than 300 feet deep. There are 11 water supply wells for industrial purposes in Allen Parish with 6 wells installed in the Chicot aquifer and 5 wells installed in the Evangeline aquifer.

Groundwater is used for municipal and rural public supply in Allen Parish. There are 11 municipal public supply wells and 11 rural public supply wells. These wells predominantly are installed in the Evangeline aquifer. The Evangeline aquifer wells include 5 municipal public supply wells near Oakdale, one municipal public supply well at Oberlin, 2 municipal public supply wells at Elizabeth, and one municipal public supply well at Kinder. There is one municipal supply well installed in the Chicot aquifer at Oberlin and one municipal public supply wells installed in the Jasper aquifer near Reeves. All 11 of the rural public supply wells are installed in the Evangeline aquifer. These include wells supplying water districts near Oberlin, Oakdale, Kinder, and Reeves. The Evangeline aquifer municipal and rural water-supply wells range from 458 to 974 feet in depth.

Groundwater withdrawals for various uses primarily are for domestic supply, public supply, and rice irrigation (Prakken and others, 2012). Drilling rig water-supply wells also have been used for water for petroleum well drilling, but typically are plugged and abandoned after their use.

The USDW consists of an aquifer or its portion, which supplies any public water system, an aquifer or its portion, which contains a sufficient quantity of water to supply a public water system, and which currently supplies drinking water for human consumption, or contains less than 10,000 mg/L of total dissolved solids (TDS) and which is not an exempted aquifer. **Figure 2-3** shows the elevation of the base of the USDW in Allen Parish and the adjoining areas.

The approximate depths to the base of fresh water in the vicinity of the following municipalities in Allen Parish are listed below (Whitfield, 1975):

Municipality or Water District	Depth to Base of Fresh Water (feet)
Elizabeth	1,800
Oakdale	1,800
Oberlin	2,200
Kinder	1,700

STRUCTURAL GEOLOGY

Normal faults occur in the subsurface of Allen Parish (Bebout and Gutierrez, 1982). In general, the fault displacements terminate in the Frio Formation or Anahuac Group so that the faults were not active after Frio deposition in the Oligocene series. Whitfield (1975) refers to two fault systems in the southern part of Allen Parish identified as the Bancroft – Mamou Fault System and

Tepetate – Baton Rouge Fault System. Faults in the southern part of Allen Parish show displacement as shallow as the Lower Miocene. In this area, the base of the USDW is shallower (approximately 2,500 feet bgs) and fresh groundwater is largely restricted to the Chicot aquifer system (Lindaman, 2023).

The formation pore water is normally pressured (hydrostatic) from the land surface to within the Eocene series in Allen Parish. Overpressured conditions, occur at the base of the Midway Group at depths of approximately 15,000 feet in the northern part of Allen Parish (Bebout and Gutierrez, 1982). Overpressured conditions become shallower to the south and are 11,000 to 12,000 feet deep at the south boundary of the parish.

SEQUESTRATION RESERVOIRS

Potential sequestration reservoir formations occur between the base of the USDW and the top of overpressured conditions. Potential sequestration reservoirs could include Miocene sand zones, Anahuac Group sand zones, Frio Formation deltaic sands, Cockfield Formation sands, and Wilcox Group sand zones.

The CO2 sequestration projects proposed for Allen Parish have anticipated using the sand zones in the Frio Formation as storage reservoirs. Section 5 of this report summarizes the proposed projects.

SECTION 3 – Louisiana Class VI Well Permit Process and Regulations

This section includes background details of the Federal and state Class VI injection well permitting and regulatory process with particular focus on how the regulations are designed to mitigate environmental risks.

For the purposes of this section of the report, geologic sequestration (GS) is defined as the long-term containment of a gaseous, liquid or supercritical carbon dioxide (CO2) stream in subsurface geologic formations (US OFR, 2010). Geologic sequestration of CO2 is permissible by use of injection well technology regulated by federal and state authorities under the Federal Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Program.

A. USEPA

The U.S. Environmental Protection Agency (EPA) is authorized by the SDWA to regulate underground injection and CO2 GS to ensure protection of underground sources of drinking water (USDW). Pursuant to that authority and responsibility, the EPA's final UIC program CO2 GS rule was published in the Federal Register on December 10, 2010, made effective on January 10, 2011 (US OFR, 2010). EPA's final rule establishes the minimum UIC Class VI CO_2 injection well permitting, operational, and end of life requirements necessary for implementation and completion of GS projects in the United States.

B. LDENR OC

The EPA granted primary enforcement authority (primacy) of the SDWA UIC Program to the LDENR Office of Conservation (hereafter "OC") on April 23, 1982, for all classes of injection wells in the program at that time, specifically Class I – V injection wells (LDENR, 2021).

Twenty-six years later, the EPA published proposed requirements for the new UIC Class VI CO2 GS injection well program in the Federal Register on July 25, 2008. Shortly thereafter in 2009, the Louisiana Legislature passed ACT 517 made law by authority of the Louisiana Governor, thereby authorizing OC to adopt CO2 GS rules.

The EPA's subsequent UIC Class VI CO2 GS final rule effective January 10, 2011, was followed by publication of OC's proposed Class VI CO2 GS requirements eventually finalized and codified in the Louisiana Administrative Code (currently LAC 43:XVII.Subpart 6.Chapter 36), effective January 20, 2021 (LOSR, 2021). Promulgation of LAC 43:XVII.Subpart 6.Chapter 36 enabled OC to submit its UIC Class VI USEPA Primacy Application, prepared April 21, 2021, and updated September 17, 2021 (LOSR, 2021).

On December 28, 2023, the EPA approved OC's Class VI program for primary enforcement authority (primacy) joining the program with OC's existing UIC primacy Class I-V programs (LDENR, 2023).

Following EPA's approval, OC's Commissioner issued on January 9, 2024, notice to all Class VI injection well interested parties informing of the EPA's primacy approval with details regarding EPA Region 6 Class VI permit application OC transmission protocol, additional Louisiana permit application requirements, and other related administrative items (LDENR, 2024).

C. OC PERMIT APPLICATION UPDATE

OC's website includes Class VI permit application information found in Appendix 1 of this report for applications that have been transferred from the USEPA Region 6 or otherwise submitted to OC thereafter. As of the update provided on January 6, 2025, two CO2 GS projects are reported to be within or in part in Allen Parish. Denbury Carbon Solutions, LLC's Draco project located in the vicinity of NW Allen Parish includes six Class VI well applications. Magnolia Sequestration Hub, LLC's Magnolia Project located south of Oberlin includes two Class VI well applications. OC's latest update indicates that neither project has an OC approved Class VI well application, nor has OC approved an application for any other Louisiana project listed in the report. There are no applications listed for the ExxonMobil proposed projects described in Section 5 of this report.

CLASS VI REGULATIONS RISK EVALUATION AND MITIGATION MEASURES

A. EPA'S CLASS VI FINAL REGULATORY PATHWAY SUMMARY

The EPA is authorized by the United States Congress to implement all tenets of law and regulations thereunder of the SDWA UIC Program. That authority includes delegating primacy to states that apply for UIC Program primacy demonstrating compliance with all applicable criteria to be granted primacy from the EPA. Of pertinent importance for the scope of this report, a state applying for UIC Program primacy must demonstrate in their EPA application that their UIC Program rules and requirements are at least as stringent as all equivalent aspects of the EPA final rules and requirements (US OFR, 1983). USEPA's December 28, 2023, approval of OC's primacy application establishes this stringency requirement as fact.

As such, for purposes of understanding how Louisiana's Class VI permit process and regulations are designed to mitigate environmental risks, it is necessary to investigate the steps taken by the EPA to evaluate and mitigate environmental risks; and sufficient to rely on the EPA's actions, and ultimately their incorporation of environmental risk evaluation results, findings, and conclusions into the final regulatory requirements to mitigate those risks.

In doing so, as further detailed in the following Subsections B and C, and respective appendices, the EPA performed a very thorough, deliberate, and comprehensive evaluation of environmental risks and has developed mitigation measures into their final Class VI rule and requirements based on a fundamentally sound and objective, inclusive process producing a reasonable and practical regulatory approach suitable for initial rule development, implementation, and state UIC program primacy adoption. However it is prudent to note that implementation of the U.S. EPA's approach with respect to preventing and mitigating environmental risks is dependent on operator compliance, timely communication, and agency interaction in all aspects of the regulatory program throughout the life cycle of these facilities.

EPA's regulatory pathway summarized above is further described below with greater detail included in respective referenced appendices in this report.

B. EPA'S PRE-REGULATION PROPOSAL / FINAL RULE EVALUATION STEPS

Pre-regulation proposal / final rule completion steps and actions taken by the EPA to evaluate CO2 GS risks and develop regulatory mitigation measures are briefly summarized by the EPA Office of Water in their guidance publication, EPA 816-F-08-032, provided below.

"How Did EPA Consult with Stakeholders in Evaluating GS and Developing the Proposal?"

"Over the past several years, EPA has coordinated with the Department of Energy, the lead U.S. agency conducting GS field research, to monitor the progress of pilot GS projects. The Agency has convened seven workshops since 2005 to discuss various technical issues associated with GS and convened two public stakeholder meetings in December 2007 and February 2008 to identify and discuss questions relevant to the effective management of CO2 GS. Each stakeholder workshop was attended by more than 200 stakeholders representing a broad range of interests including government, industry, public interest groups, and the general public. EPA also worked closely with four state co-regulators affiliated with the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission" (US EPA, 2008).

Strengthening EPA's consultation and coordination with the US Department of Energy (DOE) is to note that DOE, through its Office of Fossil Energy Carbon Storage Program (CSP) has since 1997 "significantly advanced the carbon capture and storage (CCS) knowledge base through a diverse portfolio of applied research projects", including in-house research with National Energy Technology Laboratory's Research and Innovation Center. The CSP's primary focus as reported in 2018 "is on early-stage R&D to develop coupled simulation tools, characterization methods, and monitoring technologies that will improve storage efficiency, reduce overall cost and project risk, decrease subsurface uncertainties, and identify ways to ensure that operations are safe, economically viable, and environmentally benign." Two noteworthy key goals of CSP include "Improving carbon storage efficiency and security by advancing new and early-stage monitoring tools and models" and "Improving capabilities to evaluate and manage environmental risks and uncertainty through integrated risk-based strategic monitoring and mitigation protocols." Since inception, the CSP reports that as of January 3, 2018, "over 16 million metric tons of CO2 has been injected in the United States as part of DOE's" programs (US DOE, 2018).

Further to the above briefing of steps and actions taken, as reported by the EPA in their Federal Register final CO2 GS Class VI rule publication, the agency's "final rule builds upon longstanding programmatic requirements for underground injection that have been in place since the 1980s and that are used to manage over 800,000 injection wells nationwide. These programmatic requirements are designed to prevent fluid movement into USDWs by addressing the potential pathways through which injected fluids can migrate into USDWs and cause endangerment. EPA coordinated with Federal and non-Federal entities on GS and CCS to determine how best to tailor existing UIC requirements to CO2 for GS." Steps taken in advance of the final rule publication included: "(1) Developing guidance for experimental GS projects; (2) conducting research; (3) conducting stakeholder coordination and outreach; (4) issuing a proposed rulemaking and soliciting and reviewing public comment; and, (5) publishing a Notice of Data Availability (NODA) and Request for Comment to seek additional input on the rulemaking." Appendix 2 describes each step in greater detail as reported by the EPA final rule publication (US OFR, 2010).

C. EPA'S MANAGEMENT AND MITIGATION OF UNIQUE RISKS OF CO2 GS

Through its evaluation process steps and actions taken, the EPA identified unique environmental risks not yet contemplated at the time of rulemaking by the EPA UIC Program, to the extent and nature unique to CO2 GS. Accordingly, the EPA reports in their Federal Register final rule publication the risks from "the large CO2 injection volumes anticipated at GS projects, the relative buoyancy of CO2, its mobility within subsurface geologic formations, its corrosivity in the presence of water, and the potential presence of impurities in the captured CO2 stream", imposed the necessity to develop "tailored requirements, modeled on the existing UIC regulatory framework" to manage (mitigate) "the unique nature of CO2 injection for GS." Appendix 3 discusses each of the above risks in greater detail as reported by the EPA final rule publication (US OFR, 2010).

To mitigate these risks, the EPA reports the final rule "sets minimum technical criteria for the permitting, geologic site characterization, area of review (AoR) and corrective action, financial responsibility, well construction, operation, mechanical integrity testing (MIT), monitoring, well plugging, post-injection site care (PISC), and site closure of Class VI wells for the purposes of protecting underground sources of drinking water (USDWs). The elements of this rulemaking are based on the existing Underground Injection Control (UIC) regulatory framework, with modifications to address the unique nature of CO2 injection for GS. This rule will help ensure consistency in permitting underground injection of CO2 at GS operations across the United States and provide requirements to prevent endangerment of USDWs."

The EPA further notes the final rule "addresses endangerment to USDWs by establishing new minimum Federal requirements for the proper management of CO2 injection and storage in several program areas, including permitting, site characterization, AoR and corrective action, well construction, mechanical integrity testing (MIT), financial responsibility, monitoring, well plugging, PISC, and site closure. EPA believes that proper GS project management will appropriately mitigate potential risks of endangerment to USDWs posed by injection activities." Appendix 4 further describes each program area above as reported by the EPA final rule publication (US OFR, 2010).

D. OC CLASS VI REGULATORY RISK MITIGATION

With passage of Louisiana's ACT 517 of 2009 authorizing OC CO2 GS rule adoption and EPA's January 10, 2011 final UIC Program CO2 GS Class VI rule promulgation complete, OC proceeded with development and promulgation of its own Class VI rules and regulations in pursuit of EPA UIC Class VI Program primacy approval. Statewide Order No. 29-N-6 (LAC 43:XVII.Subpart 6), hereinafter also referenced as "Order", effective January 10, 2021, and revised September 2022, are the rules and regulations adopted by the OC regulating Class VI wells. These rules apply to all owners and operators of proposed and existing Class VI injection wells and projects within the state of Louisiana. The Order is part of the regulatory framework designed to oversee activities related to CO2 GS and became officially authorized for OC implementation by the EPA's December 28, 2023, approval of OC's Class VI Program primacy application.

Having met the legal requirements of the federal SDWA UIC Program for state primacy approval to be at least as stringent as EPA's Class VI rules and regulations, Louisiana's Order inherently includes all aspects of EPA's environmental risk evaluation and subsequent incorporation of regulatory mitigating measures. Additionally, OC's specific statewide risk evaluation determined certain regulatory requirements required more stringent application and/or greater specificity mitigating measures to ensure protection of public safety, welfare, and the environment.

Following notice of EPA's Class VI UIC Program primacy approval, the Louisiana Department of Energy and Natural Resources (LDENR) issued a public announcement on behalf of OC on December 28, 2023. The announcement recognized the OC Injection and Mining Division's deliberative efforts from 2019 to 2021 in preparing Louisiana CO2 GS Class VI regulations for rule promulgation, including a comprehensive review of all existing and proposed state regulations in comparison to EPA requirements.

Four noteworthy areas where Louisiana's regulations exceed, thus are more stringent than, the EPA requirements include (1) no waivers will be granted to injection depth requirements, (2) salt cavern CO2 GS is prohibited, (3) multiple well area permits will not be issued, and (4) additional monitoring and operational measures are required (LDENR, 2023). Appendix 5 further details OC's Class VI state and federal regulations comparative analysis results (LDENR, 2023).

The Order includes permitting, operations, and end of life provisions for protection of public safety and the environment. The several elements of the Order providing for safe operation of the CO2 GS projects ensuring environmental protection include site characterization, detailed Area of Review (AOR) and corrective action plan, well construction and mechanical integrity testing (MIT), testing and monitoring plan, emergency and remedial response plan, post-injection site closure care plan, well plugging and abandonment, and maintaining financial responsibility.

Those provisions found in Statewide Order 29 N-6 that have been adopted to mitigate the possible hazards of CO2 GS projects to ensure safety to the public and protection of the environment are further detailed as follows.

E. SITE CHARACTERIZATION MITIGATION MEASURES

Applicants, owners, or operators of Class VI wells must demonstrate to the satisfaction of the commissioner that the wells will be sited in areas with a suitable geologic system. The demonstration must show that the geologic system comprises an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream; confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids, and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).

F. AREA OF REVIEW AND CORRECTIVE ACTION MITIGATION MEASURES

The AOR is defined as the areal extent of the injectate plume, plus the extent of the increased pressure front induced by the injection operations. Owners or operators of Class VI wells must prepare, maintain, and comply with a plan that includes delineating the AOR, periodically reevaluating the delineation, and performing corrective actions as required by the regulation. Corrective action plans must detail how the AOR will be delineated, the frequency of re-evaluation, and how monitoring and operational data will inform any re-evaluation.

The extent of the pressure front is determined using both computational modelling and the use of monitor wells around the periphery of the AOR. The modeling to be employed is highly complex and is beyond the scope of this report. 40 CFR 146 requires that the operator produce an AOR and Corrective Action Plan on how wells within the AOR will be identified and the corrective action that will be undertaken, and whether or not the corrective action will be phased. The minimum fixed frequency of the AOR re-evaluation is not to exceed five years in which the owner or operator proposes to reevaluate the area of review.

All artificial penetrations that fall within a CO2 sequestration project's AOR are subject to corrective action review whether the well is existing or plugged. To identify wells within the Area of Review (AOR) for CO2 sequestration projects, several methods are commonly employed (US EPA, 2013):

- Review of Historical Records: This involves examining historical well records, maps, and databases to identify existing wells within the AOR. Regulatory agencies often maintain detailed records of well locations and statuses.
- Geophysical Surveys: Techniques such as seismic surveys, electromagnetic surveys, and ground-penetrating radar can help detect subsurface anomalies that may indicate the presence of wells.
- Aerial and Satellite Imagery: High-resolution aerial photographs and satellite images can be used to identify surface expressions of wells, such as well pads and access roads.
- Field Inspections: Physical inspections of the area can help verify the presence and condition of wells. This may involve visiting known well sites and looking for signs of undocumented wells.
- Risk Assessment Models: Advanced modeling techniques can predict the locations of undocumented wells based on geological and historical data. These models help prioritize areas for further investigation.
- Public and Industry Data: Leveraging publicly available data and industry reports can provide additional insights into well locations and conditions.

Corrective action is usually accomplished in one two ways. The applicant can either prove to the satisfaction of the IMD that the pressure increase in the injection interval will not increase to the point that the pressure increase will cause fluids in the wellbore to migrate upward into the USDW, or by conducting a well intervention in which the well is re-entered and the necessary plugs set in the well to prevent migration of injected CO2 from the injection interval. The properties of the fluid left in the well such as density and viscosity must also be considered in order to determine that the weight of the plugging fluid is sufficient to prevent the displacement of the plugging fluid by the injectate.

However, in discussions with Patrick Courrèges of LDENR on October 24, 2024, it was stated that only CO2 resistant cement plugs placed in the well will be considered adequate for corrective action purposes.

The regulation allows for phased corrective action, which means that corrective actions can be addressed in stages. Some corrective actions may be performed prior to injection, while others may be addressed during the injection phase of the project.

The phasing is determined based on the conditions of the AOR and must be adjusted if there are changes in the AOR. The plan must also ensure that site access is guaranteed for future corrective actions. This phased approach allows for flexibility in managing risks to USDWs by addressing potential issues in stages, as they become relevant during the project's lifecycle. It is a strategic method to ensure that environmental safety measures keep pace with the operational aspects of CO2 sequestration projects.

Deficient wells were found in both the northern and southern portions of the parish in this study. The northern half of the parish has far fewer wells than the southern half and thus far fewer deficient wells. The distribution of the wells in the northern part of the parish are configured in such a manner that a CO2 sequestration project may not include a significant number of deficient wells that will be present within the AOR. This is not as probable in the southern half of the parish due to the large number of wells drilled in this area.

Operating wells pose the same issues as improperly plugged wells. There may be instances where the well lacks cement isolation of the top of the injection zone and base of the USDW. For this reason, operating wells are subject to the same requirements of AOR review and corrective action as the other wells within the AOR.

G. WELL CONSTRUCTION AND MIT MITIGATION MEASURES

Operators must follow specific construction requirements for Class VI wells to ensure integrity of the well. All phases of Class VI well construction must be supervised by a person knowledgeable and experienced in practical drilling engineering and is familiar with the special conditions and requirements of injection well construction. Proper casing and cementing are crucial to prevent movement of fluids into or between USDWs. Casing and cement must adhere to American Petroleum Institute, ASTM International, or comparable standards acceptable to the commissioner. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs.

All well materials must be compatible with fluids that the materials may be expected to come into contact. CO2 is highly corrosive and careful consideration must be taken in the selection of steel alloys and cement used in well construction. Casing and cement or other materials used in the construction of each Class VI well must also have sufficient structural strength and be designed for the life of the geologic sequestration project.

Class VI wells are to be designed to meet the following requirements:

- Prevent the movement of fluids into or between USDWs or into any unauthorized zones;
- Allow the use of appropriate testing devices and workover tools; and
- Allow for continuous monitoring of the annulus space between the injection tubing and long string casing.

The surface casing of any Class VI well must extend into a confining bed-such as a shale-below the base of the deepest formation containing a USDW. The casing must be cemented with a sufficient volume of cement to circulate cement from the casing shoe to the surface. The commissioner will not grant an exception or variance to the surface casing setting depth.

Mechanical Integrity

The permittee of a Class VI injection well will be required to establish mechanical integrity prior to commencing injection and on a schedule determined by the rules or the commissioner. Thereafter, the owner or operator of Class VI injection wells must maintain mechanical integrity. The Class VI injection well owner or operator must give notice to the commissioner when it is determined the injection well is lacking mechanical integrity. Upon receiving such notice, the operator must immediately cease injection into the well. The well shall remain out of injection service until well mechanical integrity is restored to the satisfaction of the commissioner.

A demonstration of external mechanical integrity or proof that fluid is not migrating behind the casing is required at least once every 12 months until the injection well is permanently plugged and abandoned. External mechanical integrity can be demonstrated by running an approved tracer-type survey such as a radioactive tracer, oxygen-activation log or similar logging tool, or a temperature or noise log.

Wellhead Identification and Protection

A protective barrier is to be installed and maintained around the wellheads, piping, and above ground structures that may be vulnerable to physical or accidental damage by mobile equipment or trespassers.

H. TESTING AND MONITORING MITIGATION MEASURES

The monitoring requirements for Class VI wells under the Louisiana Office of Conservation Statewide Order 29 N-6 include a comprehensive set of regulations designed to ensure the safe and environmentally responsible operation of geologic sequestration projects.

The owner or operator of a Class VI well must prepare, maintain, and comply with a Testing and Monitoring Plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The Testing and Monitoring Plan must be included with the permit application and must include a description of how the owner or operator will meet these requirements including accessing sites for all necessary monitoring and testing during the life of the project.

Testing and monitoring associated with geologic sequestration projects must include, at a minimum, the requirements below:

1) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;
2) Installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the tubing-casing annulus; and the annulus fluid volume added. Continuous monitoring is not required during well workovers;
3) 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 to ensure that the well components meet the minimum standards for material strength and performance by: analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or using an alternative method approved by the commissioner.

The owner or operator is required to periodically review the Testing and Monitoring Plan to incorporate monitoring data collected, operational data collected, and the most recent area of review re-evaluation performed. In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator must submit an amended testing and monitoring plan or demonstrate to the commissioner that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the commissioner, must be incorporated into the permit, and are subject to the permit modification requirements.

Monitor Wells

The location and number of monitoring wells is based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors.

The monitoring frequency and spatial distribution of monitoring wells is based on baseline geochemical data that has been collected and on any modeling results in the Area of Review evaluation.

Well and Facility Monitoring

Operators are required to monitor the injection well and the geologic sequestration project to confirm that USDWs are not endangered. This includes tracking the movement of the carbon dioxide plume and pressure front, as well as monitoring the integrity of the well and the confining zone. Continuous recording devices must be installed, used, and maintained in proper working order for each well. Continuous recording devices will monitor:

- Surface injection or bottom-hole pressure;
- Flow rate, volume and/or mass, and temperature of the carbon dioxide stream;
- Tubing-casing annulus pressure and annulus fluid volume; and
- Any other data specified by the commissioner.

Continuous recordings will consist of digital recordings. Instruments will be weatherproof or housed in weatherproof enclosures when exposed to the outdoors.

Alarms and automatic shutdown systems designed to actuate on exceedance of a predetermined monitored condition must be installed and maintained in proper working order. All alarms must be integrated with any automatic shutdown system. At the discretion of the commissioner, down-hole shut-off systems (e.g., automatic shut-off, check valves) or other mechanical devices that provide equivalent protection may be approved.

If a shutdown is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well is lacking mechanical integrity, or if monitored well parameters indicate that the well may be lacking mechanical integrity, the owner or operator must immediately cease injection and take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone and notify the commissioner within 24 hours.

It is crucial that injection rates are closely monitored to ensure that the injection rates do not exceed the permitted maximum rate. This monitoring requirement is important since the plume model uses an injection rate as an input; therefore, the assigned injection must be adhered to closely.

All emergency shutdown systems shall be failsafe. The operator shall function-test all critical systems of control and safety at least once every six months. This includes testing of alarms, test tripping of emergency shutdown valves ensuring their closure times are within design specifications, and ensuring the integrity of all-electrical, pneumatic, and hydraulic circuits.

Air Monitoring

The commissioner may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.

The design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review. The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with the requirements to protect the USDW.

I. EMERGENCY AND REMEDIAL RESPONSE MITIGATION MEASURES

As part of the permit application, the owner or operator must provide the commissioner with an Emergency and Remedial Response Plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:

- Immediately cease injection,
- Take all steps reasonably necessary to identify and characterize any release;
- Notify the commissioner within 24 hours, and
- Implement the emergency and remedial response plan approved by the commissioner.

Statewide Order 29 N-6 does not explicitly require that operators include in their emergency response plan the requirement to notify the National Response Center and first responders. However, emergency response plans normally include this requirement.

The owner or operator shall review the emergency and remedial response plan at least once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the commissioner that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the commissioner, must be incorporated into the permit, and are subject to the permit modification requirements.

J. POST-INJECTION SITE CARE AND CLOSURE MITIGATION MEASURES

After injection ceases, operators must continue to monitor the site to ensure that USDWs remain protected. This post-injection care period is determined based on the behavior of the injected carbon dioxide and the presence of USDWs.

The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of the regulations and is acceptable to the commissioner. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application.

The post-injection site care and site closure plan must include the following information:

- The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s),
- The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation,
- A description of post-injection monitoring location, methods, and proposed frequency,
- A proposed schedule for submitting post-injection site care monitoring results to the commissioner and to the USEPA, and
- The duration of the post-injection site care timeframe and, if approved by the commissioner, the demonstration of the alternative post-injection site care.

Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the commissioner-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the commissioner. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under is submitted and approved by the commissioner.

K. WELL PLUGGING AND ABANDONMENT MITIGATION MEASURES

Once the post-injection site care period is complete, wells must be properly plugged and abandoned to prevent future movement of fluids into USDWs.

Before well plugging, the owner or operator must flush each Class VI well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.

The owner or operator of a Class VI well is required to prepare, maintain, and comply with a plan acceptable to the commissioner. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

The well plugging plan must be submitted as part of the permit application, must be designed in a way that will prevent the movement of fluids into or between USDWs or outside the injection zone, and must include the following minimum information:

1) Appropriate tests or measures for determining bottomhole reservoir pressure,
2) Appropriate testing methods to ensure external mechanical integrity,
3) A description of the size and amount of casing, tubing, or any other well construction materials to be removed from the well before well closure,
4) That prior to the placement of plugs, the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method,
5) The type and number of plugs to be used,
6) The placement of each plug, including the elevation of the top and bottom of each plug,
7) The type, grade, yield, and quantity of material, such as cement, to be used in plugging. The material must be compatible with the carbon dioxide stream,
8) The method of placement of the plugs,
9) Pre-closure and proposed post-closure well schematics,
10) That each plug shall be appropriately tagged and tested for seal and stability,
11) That the well casings shall be cut at least five feet below ground surface for land-based wells, and at least 15 feet below the mud line for wells at a water location,
12) That upon successful completion of well closure of a land-based well, a one-half (1/2) inch steel plate shall be welded across all casings and inscribed with the wells state serial number and date plugged and abandoned, and
13) Any addition information that the commissioner may require.

L. FINANCIAL RESPONSIBILITY MITIGATION MEASURES

The permit shall require the permittee to maintain financial responsibility and resources to close, plug, and abandon the underground injection wells and, where necessary, related surface facility, and for post-injection site care and site closure in a manner prescribed by the commissioner. Closure funding must be no less than the amount identified in the cost estimate of the closure plan and any required post-injection site care.

The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response. The cost estimate must be performed for each phase separately and must be based on the costs to the Office of Conservation of contracting a third party to perform the required activities.

M. OC REGULATORY MITIGATION MEASURES SUMMARY

Provisions directed towards public safety and protection of the environment in the operation of a CO2 sequestration project constitute a significant portion of Statewide Order No. 29 N-6.

Proper site characterization and the modeling of the CO_2 plume and pressure front in the sequestration reservoir is critical in determining the suitability of the reservoir for the purpose of CO_2 sequestration. The modeling will determine the extent of the Area of Review around the injection well, which will in turn identify the existing wells requiring corrective action. Well construction requirements specify that all materials used in the construction be compatible with the CO_2 in which it may come in contact with. Well integrity must be maintained at all times. Extensive monitoring of the injection operations are specified, as well as the use of monitor wells to detect any introduction of CO_2 into fresh water sands. Air monitoring may also be required to the detect the presence of CO_2 in the air and soil surface around the well.

Plugging and abandonment regulations have been adopted that ensure that the wells still have adequate mechanical integrity at the end of operations and that the well is plugged in a manner as to ensure that the CO_2 will stay in the injection zone. Post closure care provisions require that the project is monitored for a period of up to fifty years to verify that the pressure of the CO_2 plume has dissipated and that the supercritical CO_2 remains within the project AOR. Financial security will remain in place during the post closure care period to pay for the post closure monitoring and any needed remedial care. Finally, the requirement to maintain a facility Emergency Response Plan and review it every five years is an additional safety factor.

LOUISIANA CLASS VI REGULATIONS TECHNOLOGY REQUIREMENTS

Louisiana's Class VI well permit application, pre-operation, operation, and closure stages of every CO_2 GS project requires timely, appropriate, and adequate application and interpretation of results derived from many geologic diagnostic/analytical tools and techniques for use by both the permit applicant/operator and the regulatory agency to determine project efficacy and ensure protection of public safety, welfare, the environment, and USDWs for the life of the project.

Site and project specific geophysical, geomechanical, and geochemical information is necessary for compliance with LAC 43:XVII.Chapter 36 permitting and regulatory programs and plans including the pre-operation formation testing program, stimulation program, AOR and corrective action plan (CAP), testing and monitoring plan, injection well plugging plan, and post-injection site care and site closure plan. LAC 43:XVII.3607.C.2.

The various technologies required or available for CO_2 GS project permitting and regulatory compliance is organized in three general stages spanning from project inception, through operations, to end of life. GEC has summarized the various technologies and included each in one of three stages representing the primary, prominent, or singular stage of use. Stage 1 includes site characterization/pre-operation technology, Stage 2 includes injection operation technology, and Stage 3 includes site closure technology. It is necessary to note that use of some of the listed technologies in each stage are required or may be utilized in more than one or all three stages.

Stage 1 - Site Characterization/Pre-Operation Technology

Performing site characterization, i.e., CO_2 GS formation (reservoir) characterization, using site-specific wireline logging and formation core sampling/testing information is a critical step necessary in the permitting process for geologic mapping and computational modeling to predict the extent of the CO2 plume and formation pressure front and establish the AOR and Corrective Action Plan. Use of an on-site Class V Strat Test well may be necessary to fully characterize the site and obtain the required site-specific data for Class VI permitting purposes. Well logging and core sampling/testing will follow installation of the Class VI injection well, prior to injection operations to verify and complete mapping and modeling to establish the pressure front and plume AOR.

The following technologies are available for permit applicants/operators to utilize to demonstrate compliance with applicable permitting and pre-operation AOR and CAP requirements.

A. Open-Hole Logging

Open-hole logs are crucial tools used to gather detailed information about the geological formations encountered during drilling. Key uses include formation evaluation for measurements of resistivity, porosity, and rock density which are essential for reservoir characterization and identifying/verifying suitable injection formations and confining strata. The data collected is used to evaluate and understand the types of rocks, their permeability, and the potential for injectate fluid flow to guide decisions related to well completion and injection operation strategies (Asquith and Krygowski, 2004).

The open-hole logs required when drilling a Class VI well include:

- Resistivity Log - These tools induce a current in the formation and measure the resulting conductivity, which is then inverted to obtain electrical resistivity of the formation. Formations, and fractures, filled with conductive fluids (like water) will show lower resistivity, while those filled with hydrocarbons or air will show higher resistivity.
- Gamma-Ray Log - Used to identify lithology by measuring the natural gamma radiation emitted by rocks. This radiation primarily comes from the decay of radioactive isotopes such as uranium, thorium, and potassium.
- Spontaneous Potential Log - These logs measure the natural voltage difference between a movable electrode in the borehole and a fixed reference electrode at the surface. This voltage difference arises due to electrochemical and electrokinetic potentials in the formation. The SP log is used to identify sand zones from shale (clay) zones and to assess the salinity of pore water in permeable zones.
- Density Log - Measures the electron density of the formation, which is then converted to bulk density. Porosity is calculated by comparing the bulk density to the known densities of the rock matrix and the fluid in the pores.
- Neutron Log - Measures the hydrogen content in the formation, which correlates with the amount of fluid-filled porosity. Neutrons emitted from the tool are slowed down by hydrogen atoms, and the count rate of slowed neutrons is used to estimate porosity.

- Sonic Log - Measures the travel time of acoustic waves through the formation. The speed of these waves is affected by the porosity and the type of fluid in the pores. The slower the wave, the higher the porosity.
- Caliper Log - Measures the diameter of the borehole at a given depth and calculates the borehole volume.
- Fracture Finder Logs - Fracture finder logs, also known as fracture identification logs, are specialized tools used in the oil and gas industry to detect and analyze fractures within a reservoir. The types of fracture finder logs available for use include:
  - Image Log - Tools like the Formation MicroScanner (FMS) or Borehole Televiewer (BHTV) create high-resolution images of the borehole wall. These images help identify fractures by showing variations in the borehole wall's texture and structure.
  - Dipmeter Log - High-resolution dipmeters, such as the Fracture Identification Log (FIL), use multiple arms to measure the borehole's diameter at different orientations. Variations in these measurements can indicate the presence and orientation of fractures.
  - Sonic Log - Sonic amplitude logs measure the attenuation of acoustic waves. Vertical and high-angle fractures tend to attenuate compressional waves more, while horizontal and low-angle fractures affect shear waves.
  - Resistivity Log – See above.

B. Core Sampling/Testing

Site-specific well bore core sampling and testing data is also essential to verify and complete reservoir characterization during the permitting process.

Core samples are cylindrical sections of rock or sediment extracted from the well. Core sampling is necessary for geologic analysis to determine geological characteristics such as porosity, permeability, and fluid content, and formation properties such as strength and stability for drilling and completion programs. Core sampling further defines reservoir characterization to understand the nature of the pore system in the reservoir for predicting and maximizing injection performance.

The coring process is summarized as follows:

<u>Continuous cores</u> can be analyzed by conventional or whole core procedures, but conventional core analysis is most frequently used. This procedure employs a small sample to represent an interval of core and produces acceptable results when the pore system is relatively homogeneous. Conventional core analysis plugs are usually collected once per foot. Variations in pore system development or lithology require more frequent sampling. Sample density should be adequate to define net pay, hydrocarbon-water transition zones, contact levels, and formation boundaries. Sampling can be done statistically at the mid-point of each foot or the most representative sample in each foot can be selected.

Whole core analysis examines the complete length of full-diameter core in the interval being tested and affords the maximum possible sample size. Large samples are mandatory in heterogeneous formations in which most of the porosity and permeability are due to fractures, solution vugs (cavities), or erratically developed pore systems. In these cases, the volume of individual pore spaces may be large in relation to the size of conventional core analysis plug samples. A variation of whole core analysis, called full-diameter analysis, utilizes selected lengths of a core rather than the entire core.

Sidewall core analysis is performed on cores recovered by any of the sidewall coring techniques.

C. Class V Stratigraphic Tests

A Class V stratigraphic test well is a type of injection well used primarily for geological exploration.

The Class V well category includes wells that inject non-hazardous fluids underground, either into or above an underground source of drinking water. These wells are not classified under Classes I-IV or Class VI and can range from simple shallow wells to complex experimental injection technologies. A Class V stratigraphic test well is a well drilled specifically to gather information about the geological layers (strata) and structures beneath the surface providing site-specific geophysical, geomechanical, and geochemical information for CO2 GS Class VI injection computational modeling and geologic mapping of subsurface formations. A Class V stratigraphic test well could also be used to inject fluids for studying geological formations and data collection without posing a risk to drinking water sources for CO2 GS Class VI well permitting and regulatory compliance.

D. Geomechanical Surveys

In CO2 sequestration projects, geomechanical surveys are crucial for ensuring the stability and integrity of the storage site. These surveys typically involve a combination of field data collection, laboratory experiments, and numerical modeling to provide a comprehensive understanding of the geomechanical behavior of the storage site (Babarinde, 2023).

Geomechanical surveys collectively help in assessing and mitigating risks associated with CO2 sequestration, ensuring that the storage sites are safe and effective. Key types of geomechanical surveys available for use at CO2 GS projects are listed below (Sminchak, 2014).

- Pore Pressure-Stress Coupling – This evaluation involves understanding how the injection of CO2 affects the pressure within the rock pores and the overall stress distribution in the reservoir.
- Fault Reactivation – This survey assesses the risk of existing faults becoming reactivated due to increased pressure from CO2 injection, which could potentially lead to fluid migration outside of containment or leakage.

- Caprock Integrity – This survey ensures that the caprock, which acts as a seal to prevent CO_2 from escaping, remains intact and effective under the new stress conditions.
- Rock Physics – This survey includes studying the physical properties of the rocks, such as porosity, permeability, and compressibility, to predict how they will behave under CO_2 injection.
- Induced Seismicity – The survey includes monitoring for any seismic activity that might be triggered by the injection process, which could indicate changes in the geomechanical stability of the site.
- Geophysical Logging – This method involves using tools lowered into boreholes to measure the physical properties of the rock formations to identify fractures, faults, and other features that could impact CO_2 storage.
- Seismic Surveys - These surveys use seismic waves to create detailed images of the subsurface for mapping the geological structures and identifying any potential issues that could affect CO_2 storage.

E. Geophysical and Geochemical Surveys

A wide range of geophysical and geochemical monitoring technologies have been implemented in CO_2 sequestration pilot tests, demonstration projects, and commercial-scale projects. These include gravity surveys, multicomponent seismic monitoring, electrical and electromagnetic methods, as well as soil gas and groundwater monitoring. These technologies are primarily used in the injection operation stage.

F. Pressure Transient Tests

Data collected from geophysical surveys, geochemical surveys, and pressure transient tests can be used for site characterization purposes and is noted as such here. However, these technologies are primarily used during the injection operation stage and are detailed in the Stage 2 Injection Operation section of this report.

G. Geologic Maps

Geologic maps are primarily constructed using data obtained from open hole logs run on nearby wells and seismic data. Geologic mapping can include use of structure, cross-section, isopach, and fault plane maps for identifying the various trapping mechanisms in the reservoir that will prevent the migration of the CO_2 plumes out of the intended subsurface storage area.

Trapping mechanisms are crucial for containing the CO_2 plumes in the reservoir and preventing its migration. The primary types of trapping mechanisms are listed and summarized below:

- Structural Traps

- Anticline Traps - Formed by the folding of rock layers into an arch-like structure. The hydrocarbons accumulate at the crest of the fold, with impermeable rock layers above preventing upward migration.
- Fault Traps - Created when reservoir rock is displaced along a fault line. The movement can juxtapose permeable and impermeable layers, trapping hydrocarbons.
- Salt Domes - Occur when a salt layer moves upward, deforming the surrounding rock layers and creating traps around the salt structure.

- Stratigraphic Traps
  - Unconformity Traps - Formed where there is a break or gap in the geological record, with older rocks overlain by younger, impermeable rocks.
  - Pinch-out Traps - Occur where a reservoir rock layer thins out or pinches off against an impermeable rock layer.
- Combination Traps - These involve both structural and stratigraphic elements, such as a faulted anticline where both the fold and the fault contribute to trapping hydrocarbons.
- Capillary Trapping - This mechanism involves the trapping of hydrocarbons in the pore spaces of the reservoir rock due to capillary forces. It is significant in enhanced oil recovery (EOR) and carbon capture and storage (CCS) applications.

H. Computational Modeling

Computational modeling plays a crucial role in CO2 sequestration projects, especially during permitting as modeling provides the technical basis for establishing the predicted extent of the injection formation pressure front and plume boundaries for the AOR and CAP aspects of regulatory compliance. Modeling also continues to provide essential information during the injection operation stage of CO2 projects for monitoring geologic storage of CO2. However, for simplicity, modeling is fully described in this section of the report.

The primary purposes of computational modeling use for Class VI CO2 GS projects are summarized below (Tchelepi and others, 2023).

- Predicting CO2 Behavior – Modeling is used to predict how CO2 will behave once injected into the subsurface. This includes understanding the flow, distribution, and long-term fate of CO2 in geological formations.
- Assessing Storage Capacity - Models can estimate the storage capacity of different geological formations, ensuring that the selected site can safely and effectively store the required amount of CO2.
- Evaluating Risks - Computational models are used to assess potential risks, such as CO2 leakage or migration into unintended areas. This is essential for ensuring the safety and integrity of the storage site.

- Optimizing Injection Strategies - By simulating various injection scenarios, models help optimize the injection process to maximize storage efficiency and minimize risks.
- Monitoring and Verification - Models support the design of monitoring programs to verify that CO_2 remains securely stored over time and are used to interpret monitoring data and adjust strategies as needed.
- Cost and Time Efficiency - Computational modeling allows for the testing of multiple scenarios and conditions without the need for expensive and time-consuming field experiments.

Common types of computational models and primary uses for CO_2 projects are summarized below:

- Flow and Transport Modeling - These models simulate how CO_2 moves through porous rock formations, predicting its spread and interaction with existing fluids. This helps in understanding the efficiency and safety of the sequestration process.
- Geomechanical Modeling - These models assess the mechanical stability of the storage site to predict how the injection of CO_2 might affect the stress and strain in the surrounding rock, which is crucial for preventing leaks and ensuring long-term storage integrity.
- Reactive Transport Modeling – This modeling involves simulating the chemical reactions between CO_2, water, and minerals in the rock. These reactions can affect the porosity and permeability of the storage site, influencing the long-term behavior of the stored CO_2.
- Deep Learning and AI - Advanced computational models use deep learning and AI to create surrogate models that can predict the behavior of CO_2 storage systems more efficiently. These models can handle complex datasets and provide faster predictions compared to traditional numerical simulations.
- Risk Assessment and Management - Computational models help in identifying potential risks associated with CO_2 sequestration, such as leakage or induced seismicity. By simulating various scenarios, these models aid in developing strategies to mitigate these risks.

These models integrate various physical, chemical, and geological data to provide a comprehensive understanding of the CO_2 sequestration process, making them indispensable tools in the development and management of CO_2 storage projects.

Following Class VI well installation, additional formation and well evaluation is necessary to ensure well integrity and collect site specific formation information for computational modeling, AOR, and CAP finalization for LDENR approval prior to commencement of CO_2 injection operations.

Appendix 6 includes Class VI well construction and completion technical details and regulatory requirements for casing and cementing, casing and casing seat tests, tubing and packer, pre-injection logging, sampling, and testing requirements. LAC 43:XVII.3617.

Prior to CO_2 injection operations, a final AOR computational model and CAP must be completed based on the additional technical data derived from well installation and evaluation required in LAC 43:XVII.3617, and approved by LDENR.

Stage 2 - Injection Operation Technology

During active CO_2 injection operations, operators must implement their approved testing and monitoring plan and submit all results and data interpretations to LDENR to demonstrate safe and proper well and storage operations throughout the duration of injection operations. Details of the testing and monitoring requirements of LAC 43:XVII:6.3625 are provided in Appendix 7.

Numerous technologies are available for use to demonstrate injection well mechanical integrity and monitoring CO_2 injection and storage operations. These technologies are listed and summarized below.

A. Geophysical Surveys

Geophysical surveys play a crucial role in CO_2 sequestration projects by providing means to evaluate, monitor, and verify adequate containment and storage of CO_2 in geological formations at CO_2 GS sites for ensuring the safety and effectiveness of CO_2 sequestration operations by providing detailed information about the subsurface, including detection of any potential fluid migration pathways, leaks, or other containment related issues.

Geophysical surveys include indirect methods capable of accessing a much larger area than can be achieved by direct sampling such as coring and logging techniques. As such, certain geophysical survey techniques may also be utilized and beneficial during the site characterization and pre-operation stage.

Key geophysical techniques and commonly used surveys available to project operators are detailed below (Ma and others, 2016) (Ceyhan and others, 2022).

- Seismic Surveys - These are the most commonly used geophysical method. The technique involves sending sound waves into the ground and measuring the reflected waves to create detailed images of subsurface structures. This technique is useful in identifying suitable storage sites and monitoring CO_2 fluid movement in the subsurface.
    - Vertical Seismic Profiling (VSP) - This method involves placing seismic sources at the surface and receivers in the wellbore to create detailed images of the subsurface. VSP can be used to monitor the movement and distribution of CO_2 over time.

- Cross-Well Seismic Surveys - These surveys use seismic sources and receivers placed in different wells to create high-resolution images between the wells. This technique is particularly useful for monitoring the CO_2 plume and detecting any potential leakage.
- Microseismic Monitoring - This technique involves monitoring small-scale seismic events induced by CO_2 injection. It helps in understanding the geomechanical response of the storage formation and ensuring the integrity of the storage site.
- Time-Lapse (4D) Seismic Surveys - These surveys involve repeating seismic measurements over time to detect changes in the subsurface caused by CO_2 injection. Time-lapse seismic data can provide valuable information on the behavior and migration of the CO_2 plume.

- Gravity Surveys – These surveys measure variations in the Earth's gravitational field caused by density changes in the subsurface. Gravity surveys can be used to detect the presence and movement of CO_2 by identifying changes in the density of the storage formation.
- Electrical Resistivity Tomography (ERT) - ERT involves injecting electrical currents into the ground and measuring the resulting voltage differences. This technique is used for mapping the distribution of CO_2 in the subsurface by detecting changes in electrical resistivity.
- Electromagnetic (EM) Surveys - Cased-hole EM surveys measure the electrical resistivity of the subsurface, which can change due to the presence of CO_2. This method helps in tracking the CO_2 plume and ensuring it remains within the designated storage area.

Geophysical surveys are crucial for ensuring the safe and effective storage of CO_2, as they provide detailed information on the subsurface conditions and the behavior of the injected CO_2 and are often used in combination to provide a comprehensive understanding of the subsurface (Ma and others, 2016).

B. Cased-Hole Logging

In addition to the above described geophysical survey techniques commonly used in cased-holes, various logging techniques summarized below are available to monitor and ensure the effectiveness and safety of the injection process (Ceyhan and others, 2022).

- Cased-Hole Logging - Various logging tools can be run in cased holes to measure properties such as porosity, saturation, and pressure. These logs help in understanding the reservoir conditions and the impact of CO_2 injection.
- Tracers and Fluid Sampling - Tracers are injected along with CO_2 to track its movement. Fluid samples are collected to analyze the chemical interactions between CO_2 and the formation.

C. Pressure Transient Test

Pressure transient (fall-off) testing (PTT) is a crucial tool in CO_2 sequestration projects. Primary uses during operations include monitoring the CO_2 plume, leak detection, and assessing injection efficiency. However, the technology is also used for assessing reservoir characterization properties such as formation permeability and porosity for predicting CO_2 behavior once injected (Tran and Zeidouni, 2018).

During CO_2 injection operations, PTT pressure data is used to track and monitor the movement and spread of the CO_2 plume within the reservoir. Conducting periodic PTT can be used to detect potential leaks by monitoring changes in pressure that might indicate CO_2 escaping from the intended storage zone. PTT data can be evaluated to determine the efficiency of CO_2 injection for optimizing the injection process and ensuring effective CO_2 storage operations.

The Louisiana Department of Energy and Natural Resources (LDENR) has specific requirements for pressure fall-off testing in CO_2 sequestration projects, particularly for Class VI wells. The requirements include periodic testing to monitor the integrity of the CO_2 injection well and the surrounding geological formations. The tests should collect data on pressure, temperature, and fluid composition to assess the behavior of the injected CO_2 and the response of the reservoir. The operator must also analyze and report PTT results and data interpretations to the LDENR to ensure the CO_2 is being sequestered safely and effectively.

These uses make pressure transient testing an indispensable tool in the successful implementation and monitoring of CO_2 sequestration projects. Key uses are further described below (Tran and Zeidouni, 2018).

- Reservoir Characterization - PTT helps determine the properties of the reservoir, such as permeability, porosity, and pressure distribution. This information is essential for understanding how CO_2 will move and be stored in the subsurface.
- Wellbore Conditions - By analyzing pressure data from the wellbore, PTT can identify issues such as well integrity, potential leaks, and the effectiveness of the injection process.
- CO_2 Plume Tracking - PTT can be used to track the movement of the CO_2 plume within the reservoir. This is done by monitoring pressure changes at various observation wells, which helps in understanding the extent and behavior of the CO_2 plume.
- Flow Regimes Identification - Log-log pressure diagnostic plots from PTT can identify different flow regimes in the reservoir. This is beneficial in understanding how CO_2 interacts with the reservoir rock and fluids.
- Geomechanical Effects - PTT can also provide insights into the geomechanical effects of CO_2 injection, such as changes in stress and potential for induced seismicity.

- History Matching and Model Validation - The data obtained from PTT can be used to validate and refine reservoir models, ensuring that predictions of CO_2 behavior are accurate and reliable.
- Boundary Condition Identification - By analyzing pressure data from drawdown and buildup tests, pressure transient testing can identify the fluid flow boundary conditions of the reservoir. This includes determining whether the boundaries are open, closed, semi-open, or infinite, which affects the storage capacity and the spread of the CO_2 plume.
- Monitoring CO_2 Plume - PTT allows for tracking the movement and behavior of the CO_2 plume within the reservoir. This is essential for ensuring that the CO_2 remains contained and does not migrate to unintended areas.
- Geomechanical Assessment – PTT can be used to assess the geomechanical risks associated with CO_2 injection, such as fault reactivation and seal integrity, thus contributing to designing safe injection strategies that minimize the risk of inducing seismic activity or compromising the storage site.
- Optimization of Injection Strategies - The data obtained from pressure transient tests can be used to optimize injection rates and volumes, ensuring efficient and safe storage of CO_2.

D. Geochemical Surveys

Geochemical information plays a crucial role in CO_2 sequestration, ensuring the safe and effective storage of carbon dioxide in geological formations. For Class VI permitting and CO_2 GS operations, general objectives of geochemical surveys are listed and summarized below (Jun and others, 2012).

- Understanding Reservoir Characteristics - Geochemical analysis helps in understanding the chemical composition of the reservoir rocks and fluids. This information is essential to predict how CO_2 will interact with the reservoir environment, ensuring that the injected CO_2 will remain securely stored.
- Monitoring and Safety - By analyzing the geochemical properties, operators can monitor changes over time, which is vital for detecting any potential leaks or unintended migration of CO_2. This ensures the long-term safety and integrity of the storage site.
- Regulatory Compliance - Louisiana's regulations are designed to be stringent to protect the environment and public health. Geochemical analysis is part of the comprehensive data required to demonstrate that a proposed sequestration site meets all safety and environmental standards.
- Predicting Long-term Behavior - Geochemical data helps in modeling the long-term behavior of CO_2 in the subsurface. This includes understanding potential chemical reactions between CO_2, reservoir rocks, and formation fluids, which can affect the storage capacity and stability.

Geochemical surveys play a vital role in CO_2 sequestration by monitoring and understanding the chemical interactions between injected CO_2, reservoir rocks, and formation fluids. Provided below are more specific uses of geochemical surveys pursuant to the objectives listed above (Kharaka and others, 2013).

- Baseline Geochemistry - Establishing the initial chemical composition of groundwater, soil, and gases before CO2 injection begins for comparative analysis and evaluation to identify any changes caused by the sequestration process.
- Monitoring CO2 Migration - Tracking the movement of CO2 within the reservoir to ensure it remains contained in the approved formation. This involves sampling and analyzing fluids from monitoring wells.
- Mineral Trapping - Studying how CO2 reacts with minerals in the reservoir to form stable carbonate minerals, which helps in long-term storage.
- Dissolution and Precipitation Reactions - Understanding how CO2 dissolves in formation water and the subsequent chemical reactions that may occur, potentially affecting the porosity and permeability of the reservoir.
- Leak Detection - Monitoring for any signs of CO2 leakage to the surface or into groundwater, which could pose environmental risks.
- Geochemical Reactions - When CO2 is injected into a geological formation, it can dissolve in brine, react with minerals in the rock, and form stable carbonate minerals. These reactions trap CO2 and prevent it from migrating beyond the approved storage formation.
- Monitoring Technologies - Various methods listed below are used to monitor the geochemical state of the storage site.
    - Gas Monitoring - Analyzing the composition of gases in the reservoir to detect any changes.
    - Groundwater Monitoring - Checking the chemical composition of groundwater to ensure no contamination occurs.
    - Tracer Monitoring - Using tracers to track the movement of CO2 within the reservoir.
    - Isotope Monitoring - Studying isotopic ratios to understand the interactions between CO2 and the geological formation.
- Modeling and Predictions - Geochemical models are used to predict the behavior of CO2 once it is injected. These models take into account various factors such as temperature, pressure, and the presence of impurities in the CO2.
- Uncertainties and Challenges - One of the main challenges in CO2 sequestration is accurately predicting the long-term behavior of CO2 in the subsurface. This requires detailed geochemical modeling and continuous monitoring to manage uncertainties.

These surveys typically involve a combination of field sampling, laboratory analysis, and geochemical modeling to provide a comprehensive understanding of the chemical processes occurring during CO2 sequestration.

E. Monitor Wells

The LDENR regulations require implementation of an approved testing and monitoring plan during the active CO2 injection operations to "verify that the geologic sequestration project is operating as permitted and is not endangering USDWs." LAC 43:XVII.6.3625.A. Minimum testing and monitoring requirements are detailed in Appendix 7.

Monitor wells play a crucial role in CO2 sequestration projects. Here are some of their key uses (Ceyhan and others, 2022):

- Tracking CO2 Migration - Monitor wells help track the movement of the CO2 plume and pressure front within the storage reservoir to ensure that the CO2 remains within the designated storage area.
- Assessing Reservoir Integrity – Monitor wells are used to monitor the integrity of the storage reservoir and the overlying cap rock for use in detecting any potential leaks or breaches that could allow CO2 to escape beyond the approved formation boundaries.
- Groundwater Protection - Monitor wells strategically installed above the storage formation, near the base of the USDW, and in aquifer systems are essential for protecting underground sources of drinking water (USDWs) providing a means for early detection of any CO2 migration beyond the approved storage formation to mitigate and prevent CO2 migration into these water sources.
- Pressure Management - Some monitor wells are used to measure and manage pressure within the reservoir. This can involve removing formation water to reduce pressure and maintain the stability of the storage site.
- Geochemical and Geophysical Monitoring - These wells are used to collect geochemical and geophysical data, which helps in understanding the interactions between CO2, the reservoir rock, and the fluids within the reservoir.
- Long-term Monitoring - Even after CO2 injection has ended, monitor wells continue to be used to ensure the long-term stability and safety of the storage site.

Monitoring information obtained with implementation of the testing and monitoring plan is vital to ensure safe and effective implementation of CO2 sequestration projects, ensuring that the stored CO2 does not pose any environmental or health risks. The information is necessary to periodically update predictive computational modeling for CO2 pressure front and plume growth in the approved AOR and storage formation, reporting the same to the agency, and making any necessary operational or permitting modifications to ensure safe and environmentally protective ongoing and future operations at the project site.

F. Computational Modeling

Computational predictive modeling is required during the permitting process and prior to CO2 injection operations to establish the AOR and CAP. Modeling and periodic reporting must continue during injection operations and for the life of the project through an interactive process with LDENR utilizing current monitoring information available for model input, updating, and adjustments. Modeling is comprehensively discussed in the Stage 1 Site Characterization/Pre-Operation section of this report.

Stage 3 – Site Closure Technology

A. Injection Well Plugging

Following completion of active injection operations, the Class VI injection well must be properly plugged and abandoned, and the facility enter the post-injection site care and closure phase.

The Louisiana Department of Energy and Natural Resources (LDENR) oversees the regulation of Class VI wells used for CO2 sequestration. The plugging plan for these wells is a critical component of ensuring long-term environmental safety and compliance with regulatory standards. Appendix 8 includes the minimum Class VI well plugging and technical requirements in LAC 43:XVII.6.3631.A.3. Provided below is a listing of some key elements and brief summaries included in the well plugging plan:

- Well Integrity Assessment - Before plugging, a thorough assessment of the well's integrity is conducted to identify any potential issues that need to be addressed.
- Plugging Materials - The plan specifies the materials to be used for plugging, such as cement, which must meet certain standards to ensure it can effectively seal the well.
- Plug Placement - Detailed procedures for the placement of plugs at various depths within the well to prevent any potential leakage of CO2.
- Monitoring and Verification - Post-plugging monitoring to verify the effectiveness of the plug and ensure there are no leaks.
- Documentation and Reporting - Comprehensive documentation of the plugging process and submission of reports to the LDNR for review and approval.
- Environmental Safeguards - Measures to protect groundwater and other environmental resources during and after the plugging process.

B. Site Closure Monitoring

Class VI CO2 sequestration projects include a post-injection site care and site closure plan which must include ongoing pressure differential and predicted CO2 plume and pressure front monitoring (computational modeling) and periodic reporting of the same to LDENR "to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered." LAC 43:XVII.6.3633.A.1 & 2. Appendix 9 includes the minimum post-injection site care and closure plan technical requirements.

Computational modeling is detailed in the Stage 1 Site Characterization/Pre-Operation Technology section of this report.

Site closure monitoring must continue for at least 50 years or otherwise approved by the commissioner of Conservation until such time it has been demonstrated that "the geologic sequestration project no longer poses an endangerment to USDWs" as approved by the commissioner. LAC 43:XVII.6.3633.A.2.a.

Upon site closure authorization by the commissioner, all remaining monitoring wells must be plugged in a manner sufficient to prevent movement of injection or formation fluids that may endanger a USDW.

SECTION 4 – Risk Evaluation Process

This section describes the proposed methodology for study, evaluation, and quantification of environmental and public health risks associated with CO_2 sequestration projects in Allen Parish. The potential risks of concern to Allen Parish include environmental risks to surface water resources, shallow groundwater resources, deep groundwater aquifer resources, and public safety risks associated with exposure of the public to CO_2.

Project risks associated with CO_2 sequestration have been the subject of significant research efforts in the U.S. and internationally (National Energy Technology Laboratory, 2017, Best Practices: Risk Management and Simulation for Geologic Storage Projects, U.S. Department of Energy). The evaluation of project risk is fundamental to the U.S. Environmental Protection Agency (EPA) Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells and the Louisiana Department of Energy and Natural Resources (LDENR) UIC regulations.

Risk is the probability of an event that can cause a loss and the magnitude of that loss. The following three questions are part of the definition of risk (Rausand and Haugen, 2020):

- What can go wrong?
- What is the likelihood of that happening?
- What are the consequences?

To identify what could go wrong, possible events are analyzed. The possible events are derived from a hazard condition that has a potential threat for a loss. Hazard events can include initiating events and processes that reach an end state that causes harm.

The likelihood of an event happening can be a qualitative statement or could be quantitative probabilities based on observed frequencies of events.

The consequences of an event are potential harm or adverse consequences.

Risk can be quantified as the mathematical product of the probability of a hazard event and its consequences. Quantitative risk assessment can be conducted for cases where the likelihood can be quantified from known frequencies of hazard events and the consequences can be quantified based on common metrics such as cost of damages or losses. Semiquantitative evaluations of risk can include relative rankings of likelihood and consequences. **Figure 4-1** shows an example risk matrix in which the consequences (incident outcomes) are ranked vertically from low levels to high levels and the likelihood is ranked from left to right. Sequential numerical values from 1 through 5 are listed for each category of consequence and each category of likelihood of occurrence. The risk value is the mathematical multiplication of the consequence category values and the likelihood category values. For example, for consequence level 1 (first aid only or no injuries, light damage, or no environmental impact) and for likelihood category 1 (very unlikely frequency), the risk value is calculated to be 1 and is the lowest value in the risk matrix. As the consequences increase in severity and as the likelihood of occurrence increases, the corresponding risk values increase and are highest in the upper right corner of the risk matrix.

A risk matrix can be used to classify relative risks in this way based on estimations of potential damages and on potential frequencies of risk events occurring. For well-quantified hazards, it is possible to use a risk matrix to fully quantify risk levels based on numerical values of damages (such as economic cost of a risk event) and the probability that the event occurs. This type of risk analysis estimates the absolute risk based on expected costs or damages.

The quantification of likelihood in risk assessment typically uses the following correspondences (Bowden and others, 2001; Rausand and Haugen, 2020):

Likelihood of Occurrence	Order of Magnitude Probability	Qualitative Description
Very Likely (Almost Certain to Certain)	0.2 to 0.9 to near 1	Near certain event is expected to occur frequently
Likely (Highly Probable)	0.1	An event has occurred in the past or is normally experienced
Possible	0.01	Rare event that could occur
Unlikely (Remote)	0.001	Very rare event that has occurred
Very Unlikely	0.0001	Event has happened elsewhere
Highly Improbable	0.00001 (10^{-5})	Extremely rare event
Almost Impossible	0.000001 (10^{-6})	No published information on this event

The numerical values of probability can be used to represent ranges of likelihood of events.

CO2 PROJECT RISKS

Project risks for CO2 sequestration can be broadly classified as subsurface storage zone (reservoir) containment risks and risks associated with operations of project surface facilities and transportation of CO2. Subsurface containment is the ability of the reservoir to contain most or all of the injected CO2. The key technical risk is can the CO2 be stored safely in the reservoir so that it is not released to the USDW or to the land surface?

Surface and transportation facilities risks include releases of CO2 from pipelines, pumping stations, and well heads. Releases of CO2 from these facilities could be related to operations and accidents.

The consequences of releases of CO2 from the storage reservoir or from surface facilities could include impacts to public safety and environmental damages. Exposure of the public to the escape of CO2 from the system could include migration from subsurface containment into aquifers in the USDW or to the land surface including surface water resources and to the atmosphere.

CO2 HAZARDS

CO2 has well-known hazards (API, 2023). Pure CO2 is a nonflammable, colorless, and odorless gas. CO2 can exist as a gas, liquid, or solid depending on the temperature and pressure. At temperatures and pressures higher than the critical point (temperature of 87.7 °F and pressure of 1,074 psi, 72.8 atmospheres, or 7.4 MegaPascal), CO_2 is in the supercritical state and the gas phase and liquid phases are indistinguishable.

Humans and the environment are constantly exposed to CO_2. It is a by-product of cellular respiration and the CO_2 content of atmospheric air varies from 0.03% (300 ppm) to 0.06% (600 ppm).

There are physical hazards to high concentrations of CO_2 that could occur from a sudden release of CO_2. Carbon dioxide can physically displace the other components of ambient air and reduce the amount of available oxygen. Normal oxygen concentration is 20.9% of ambient air with the remainder being nitrogen, water vapor, trace gases, and particulates. If the oxygen concentration decreases below 19.5%, the atmosphere is oxygen deficient. Oxygen levels less than 6% result in cessation of breathing, convulsions, cardiac arrest, and death. If oxygen concentration is less than 19.5%, the general public should evacuate to an area with normal oxygen content.

Exposure limits for CO_2 have been established by the American Conference of Governmental Industrial Hygienists (ACGIH) and the National Institute for Occupational Safety and Health (NIOSH), and the Occupational Safety and Health Administration of the U.S. Department of Labor. The ACGIH Threshold Limit Values (TLV) have been established for occupational daily work shift exposures to CO_2 over an entire working lifetime. The ACGIH time-weighted average TLV is 5,000 ppm of CO_2 for an 8-hour work shift. This is 0.5% CO_2 in breathing air. The ACGIH short-term exposure limit (STEL) is 30,000 ppm for a 15-minute duration. This is 3% CO_2 in breathing air and would displace oxygen to less than its normal content.

The NIOSH recommended exposure limits are similar with a TWA value of 5,000 ppm of CO_2, a STEL value of 30,000 ppm of CO_2, and an Immediately Dangerous to Life and Health (IDLH) value of 40,000 ppm of CO_2. The IDLH value is equivalent to 4% CO_2 in breathing air and is immediately dangerous because of the displacement of oxygen levels that would occur at this concentration of CO_2.

The OSHA Permissible Exposure Limit (PEL) has been established as 5,000 ppm of CO_2 in breathing air. This is equivalent to 0.5% CO_2 and shows no toxicity effects in humans.

Direct toxicity of CO_2 includes impacts to kidneys after prolonged exposure to CO_2 at concentrations greater than 30,000 ppm (3%). Concentrations greater than 100,000 ppm (10%) have caused difficulty breathing, impaired hearing, nausea, vomiting, asphyxiation, and loss of consciousness within 15 minutes. These effects could be associated with oxygen deprivation.

Other hazards that could occur in a sudden release of CO_2 such as a surface pipeline failure or other rapid escape of CO_2 into the atmosphere include decreases of visibility and cold temperatures. In a sudden release, the CO_2 pressure would decrease rapidly and the expansion of the CO_2 results in sudden cooling. This can produce an opaque cloud of water vapor. The CO_2 and water vapor cloud could remain close to the ground surface unless there is wind to cause dispersion of the CO_2. The decrease of visibility is likely to be more significant at night. Near the point of release, the expansion of the CO_2 also could cause enough cooling to freeze water and result in an accumulation of ice. Daytime conditions in the atmosphere have more heating, lower humidity, and more wind activity so the decrease of visibility and cooling effects generally will be more localized and less significant.

CO2 will affect the geochemistry of groundwater and soil (Kharaka and others, 2013). The presence of CO2 from a subsurface release will decrease the pH and increase the bicarbonate alkalinity of groundwater that the CO2 comes in contact with. Depending on the mineralogy of the groundwater aquifer or soil and the geochemical conditions of the soil, the input of CO2 could decrease the pH to values on the order of 5.5 to 5.7 Standard Units (S.U.) and could increase the bicarbonate alkalinity by 100 to 3,000 mg/L. The pH decrease could result in dissolution of minerals and release of metals such as iron and manganese.

EVALUATION OF CO2 RELEASE RISK EVENTS

The principal hazard consequences for CO2 release from storage reservoirs or from project operations and transportation of CO2 are impacts to public health and the environment.

Containment risk events include the following events during the operational period and post injection (Watson, 2014):

- Leakage through permeable zones in seals
- Leakage along faults (including undetected faults)
- Excessive regional pressurization of the sequestration zone
- Leakage from wells including plugged and abandoned wells and operating wells

Releases from project surface facilities include leaks from pipelines, pumping stations, and injection well heads. Releases from project operations and CO2 transportation will occur only in the operational period and not have potential to occur post injection.

Containment risk events related to leakage through confining zone seal formations and faults have low probability of occurrence based on monitoring conducted during CO2 pilot tests, demonstration projects, and commercial-scale projects and extensive computational modeling of CO2 storage zone processes (see Sections 1 and 3 of this report and reference therein). In addition, the occurrence of multiple overlying confining zones minimizes the potential for CO2 to migrate upward from the sequestration zone to the USDW, fresh groundwater zones, or the near-surface environment. In Allen Parish, faults terminate within the Frio Formation and Anahuac Group, or at greater depths so they do not present potential pathways for CO2 to the USDW. Under the geologic conditions of Allen Parish, any potential movement along a fault, if possible, would likely leave CO2 within the confined zone deeper than the USDW so that the CO2 would remain in the subsurface. In Allen Parish and other areas of Louisiana, the prevalence of high-permeability storage reservoirs for CO2 will allow the injection pressure buildup to be relatively low so that the potential for regional pressurization of the sequestration zone is minimized.

On the other hand, existing wells and well bores can present potential direct pathways for CO2 to move from the sequestration storage reservoir to the USDW or to the near-surface and surface environment. These can include CO2 sequestration project-related wells and other earlier-drilled wells including plugged and abandoned wells.

The surface facilities (pipelines and other surface facilities, such as pumping stations and well heads of CO2 injection wells and project monitoring wells) also can provide a potential for exposure of CO2.

The following section discusses the risks posed by wells and pipelines (surface facilities).

WELLS AND PIPELINES

Two prominent areas of interest for evaluating potential CO2 sequestration environmental and public health risks in Allen Parish include all oil and gas (O&G) exploration and production (E&P) drill holes and wells (Wells), and supercritical CO2 pipeline distribution systems (Pipelines). Wells represent all LDENR recorded artificial O&G E&P penetrations, regardless of status, including active, inactive, orphaned, and plugged and abandoned wells in Allen Parish. Pipelines include all surface and/or shallow subsurface supercritical CO2 transportation and distribution system components installed to deliver CO2 to a Class VI well for geologic storage. Both areas were further evaluated by GEC focusing on potential environmental and public health risks. Additional discussion and results of risks evaluation for these areas of interest are summarized in the sections that follow.

DEFICIENT WELLS DISCUSSION

As of October 24, 2024, the LDENR SONRIS database shows a total of 1,130 O&G E&P wells have been drilled and reported to the agency in Allen Parish since 1920. Of the total number of well installations reported in Allen Parish, regulatory interest for the protection of USDWs from produced water injection operations would be the subset of these wells that would be considered deficient as further discussed below.

In the traditional O&G E&P industry including associated produced water injection operations and regulatory protection of USDWs, existing or plugged and abandoned Wells are considered to be deficient within an AOR if they lack cement isolation across the base of the USDW to prevent fluid movement into the USDW due to produced water injection operations and/or the lack cement isolation across the top of the injection zone in the well of interest to prevent injected fluids from escaping from the injection zone.

BASE OF USDW ISSUES

Wells that lack isolation of the USDW include:

- Wells in which the surface casing does not extend below base of the USDW and are currently shut-in or producing,
- Dry holes that did not have surface casing set and cemented below the base of the USDW and were not required by the Lafayette District Office of Conservation (or its predecessor) to have a cement plug set in the open hole across the base of the USDW, and
- Wells that were completed, and subsequently plugged and abandoned, but were not required during plugging and abandonment to have the USDW isolated with cement behind the pipe.

LAC 43:XIX.Subpart 1, otherwise known as statewide Order No. 29-B, does not require that the surface casing of a O&G E&P well extend below the base of the USDW. The minimum amount of surface casing required depends on the total depth of the well as given in the table below:

Total Depth, Feet	Casing Required, Feet
0-2500	100
2500-3000	150
3000-4000	300
4000-5000	400
5000-6000	500
6000-7000	800
7000-8000	1000
8000-9000	1400
9000-Deeper	1800

The base of the USDW in Allen Parish can range from depths of 2,350' in the northern tip of the parish (Black Stone 26 #1 Serial Number 234084) to 3,484' in the southern tip of the parish (Labokay 22 No. 1 Serial Number 252882).

Except for produced water disposal injection wells, as seen in the table above, none of the O&G E&P wells drilled in Allen Parish were required to have surface casing set and cemented below the base of the USDW. However, it is noted from searching SONRIS that some operators did elect to set sufficient casing in some wells that extended below the base of the USDW.

Statewide Order 29-B was amended in October 2023 to require that wells lacking surface casing set below the base of the USDW have a cement plug set across the base of the USDW in the case of dry holes. However, the LDENR Office of Conservation District Office and its predecessors, started around the early 1940s to require operators to isolate the base of exposed USDWs with cement plugs when plugging dry holes.

TOP OF INJECTION ZONE ISSUES

Wells that lack cement isolation of the top of the injection zone include:

- Dry holes that penetrated the proposed injection zone and were plugged without placing cement plugs across the top of the injection zone, and
- Wells in which the casing extends across the top of the injection zone but does not have cement placed behind the pipe. (The EPA has determined that these wells are deficient due to the corrosive nature of the CO2 with steel.)

As reported to and understood by GEC, the geologic formations in Allen Parish that have been investigated for CO2 sequestration by operators are the Frio and the Wilcox. The Frio is found at a depth of approximately 5,000 feet, whereas the Wilcox is found at a depth of approximately

10,000 feet. The formations that are found between these two are the Vicksburg/Jackson, Cockfield, and the Sparta, all of which are possible candidates for CO_2 sequestration projects.

The Frio formation has been the source of extensive petroleum production in the parish, especially in the southern portion. The wells completed in Frio could quite possibly have cement isolation of the top of the injection zone, since this isolation would be critical for production operations.

Five hundred thirty-nine oil and gas E&P wells were drilled as dry holes. These wells most likely do not have cement isolation of the top of any possible injection zones. Statewide Order 29-B does not specifically require that these formations be isolated when plugging, however, the LDENR District Manager does have at their discretion the authority to require these plugs.

CO2 SEQUESTRATION PROJECT AOR DEFICIENT WELLS

All oil and gas E&P wells with USDW or injection zone issues identified and discussed above within a CO_2 sequestration project AOR will require corrective action. As discussed elsewhere in this report, corrective action can be accomplished by well intervention techniques or modeling. Due to potential estimated intervention costs up to $1 million dollars or possibly more per well, the operator has the incentive to use computational modeling to demonstrate that a deficient well, although within a project AOR, would not come into contact with injected CO_2 fluid, and poses no other threat to the USDW, environment, and public safety, thus potentially eliminating the need for well intervention.

WELLS ENVIRONMENTAL AND PUBLIC HEALTH RISK EVALUATION

Based on research findings of the Department of Energy (DOE) report issued May 2013, any well penetrations that have not been constructed or plugged and abandoned with casing and/or cement with CO_2 corrosion inhibitors or other like additives will not withstand the corrosive effects of contact with the supercritical CO_2 stream, thus will eventually fail to prevent CO_2 from entering the well and potentially migrating out of the injection zone and into the USDW.

For CO_2-resistant cement, common additives include pozzolanic materials like fly ash, silica fume, and metakaolin, which enhance the cement's resistance to CO_2 by reducing its permeability and improving its mechanical properties. Pozzolan (Poz) cement is common in the oilfield. It is usually referred to as 50/50 Poz mix cement or other proportions.

EPA and LDENR Class VI CO_2 sequestration AOR Wells corrective action plan (CAP) requirements do not include any specific methods, cements, or cement additives necessary to be applied to address Wells determined to need corrective action. However, EPA states that "methods used must be appropriate for CO_2 injection and compatible with all fluids." (Geologic Sequestration of Carbon Dioxide, EPA, May 2013)._ Further, LDENR CAP regulations require corrective action on all wells in the AOR determined by the agency to be deficient "using methods designed to prevent the movement of fluid into or between USDWs, including *use of materials compatible with the carbon dioxide stream* [emphasis added], where appropriate." LAC XVII.6.3615.C.1.

For agency application of the aforementioned CAP requirements, GEC was informed in October 2024 that the LDENR Office of Conservation was requiring operators to demonstrate in their Class VI permit applications that any wells in the AOR penetrating the injection zone were completed or plugged and abandoned with corrosion resistant cement, where appropriate, for adequate casing and well bore protection against potential adverse corrosive effects of contact with supercritical CO_2. (personal communication, P.Courreges, October 24, 2024). For reasons detailed in the following paragraph, GEC is unable to verify if the above CAP AOR requirement has been fully implemented, remains in effect, or if other considerations have been approved by the agency.

Due to confidential business information (CBI) limitations, additional details of the agency's specific implementation of CAP requirements for individual Class VI permit applications under review by LDENR were not available at the time of publication of this report. However, it stands to reason for purposes of risk evaluation, conservatively, considering the age of most wells in Allen Parish, and no apparent reason operators to complete or plug and abandon past wells with use of CO_2 corrosion resistant cement, that most if not all traditional Allen Parish oil and gas E&P well installations within any given Class VI AOR most likely would not have been installed with methods and/or materials considered by the agency to be compatible with the CO_2 stream. Should that be the case, it should be noted that deficient cement behind pipe can be remediated by milling out a section of casing and setting a new cement CO_2 compatible plug.

It is understood and noted here there is the possibility of an unregistered well(s) existing within an AOR of a CO_2 sequestration project. It is also possible for registered wells to be incorrectly identified within an AOR, or not be identified within an AOR with use of the LDENR SONRIS database due to reporting and/or recording entry errors. Due to permit application CBI limitations previously mentioned, it is not known if these issues have been encountered by the agency, or how specifically operators and/or the agency may be addressing these possibly scenarios. However, GEC is aware of drone equipment with magnetometer and GPS technology that is available for operators to use to verify the location of registered wells and evaluate for any unregistered wells that may be located within AORs. These actions should be sufficient to consider these scenarios to be negligible pertaining to public health and environmental risks.

Although perhaps remote and minimal, it is possible for a well installed and plugged and abandoned prior to 1946 to have been utilized during the nation's war effort for metal recycling by re-entry and casing removal. Considering that there are only 19 wells that were permitted and drilled in Allen Parish prior to 1946, the coordinates of these wells are recorded in SONRIS, and, if needed, ground-truthing any of these wells that may fall within an AOR with magnetometer technology, or drone use for the same, to determine if any such wells were re-entered and casing removed for the operator and agency to determine how to mitigate the situation. As such, these actions should be sufficient to consider this scenario to be negligible pertaining to public health and environmental risks.

Leaks and releases from Class VI wells, associated equipment, and injection pump systems during active operations or during closure are possible. The operations (Section 3621), testing and monitoring (Section 3625), mechanical integrity (Section 3627), and closure (Section 3633) requirements of LAC 43:XVII.6.Chapter 36 include numerous preventative measures, early detection testing and monitoring, alarms and automatic shut-down systems, and protective closure plan provisions to prevent any potential releases from wells and surface equipment from occurring, and reducing/minimizing any such release occurrences from likely being anything greater than short term and contained to the well site, thus a negligible risk to public health and the environment.

WELLS RISK CATEGORIZATION AND RANKING

In consideration of the DOE research finding, agency CAP compliance considerations, and Wells discussion above, CO2 sequestration project environmental and public health risks from Wells can be generally categorized and qualitatively ranked from highest (1) to lowest (5) environmental/public health risk below.

1) Wells within AOR Extending Into/Through Injection Zone CO2 Plume.
2) Wells within AOR Extending Into/Through Injection Zone Pressure Front Only.
3) Wells within AOR Above the Injection Zone At or Below Primary Confining Unit.
4) Well within AOR Above Primary Confining Unit At or Below USDW.
5) Wells Nearby Outside of AOR Extending Into/Through Injection Zone.

These five categories are illustrated on **Figure 4-2** and ranked by the qualitative environmental and public health risk potential of each category, respectively, along with respective risks associated with Pipelines further discussed below, in the AOR Risk Matrix.

Category 1 Wells

The highest risk Category 1 wells penetrating into the CO2 injection zone and in contact with the plume are shown on Figure 4-2. Category 1 wells pose the greatest risk for an environmental release of CO2 extending beyond geologic storage injection zone containment potentially impacting the USDW, area aquifers, soil, surface water, and/or ecological systems, representing the greatest potential for environmental consequences. Depending on the construction and characteristics of a Category 1 well, the likelihood of CO2 movement in the well is highly probable.

A recent example of this type of movement of CO2 is at the Archer-Daniels-Midland CO2 sequestration project in Decatur, Illinois. Monitoring well VW#2 installed in both the sequestration zone (Mt. Simon Formation) and in an overlying zone that is deeper than the USDW was reported in July 2024 to have movement of CO2 and brine from the sequestration zone into the shallower monitored interval (Ironton-Galesville Formation). Based on the findings of this movement, the U.S. EPA has issued an administrative order on consent dated September 2024 to conduct repair of the monitoring well, conduct monitoring of the extent of CO2 movement, and to identify and implement remedial measures to address the migrated CO2 and brine.

Category 2 Wells

The Category 2 Wells also are expected to have higher risk due to the probability of pressure buildup of formation fluids in the sequestration zone and potential to enter the well.

Category 3 Wells

The Category 3 Wells environmental and public health ranking is lower because of isolation from the sequestration zone by the confining zone. The likelihood of contact with injection zone fluids is very unlikely to highly improbable.

Category 4 Wells

The Category 4 Wells environmental and public health ranking also is lower because of isolation from the sequestration zone by the confining zone. The likelihood of contact with injection zone fluids is very unlikely to highly improbable.

Category 5 Wells

The Category 5 Wells environmental and public health ranking is relatively low risk, but over time the risk could increase if the injected CO2 moved to the location of the well or if pressure buildup affected the well.

Although there may be other scenarios not noted herein or ranked above which could possibly occur to pose environmental or public health risks resulting from environmental release of CO2 by way of Wells, the ranked scenarios in the list above represent GEC's knowledge and understanding of regional subsurface conditions, published scientific research and literature, and applied reasonable risks contemplated under the current EPA and LDENR regulatory permitting and operational requirements promulgated for CO2 sequestration projects.

It is further contemplated here that LDENR permitting and regulatory oversight of CO2 sequestration projects will be an ongoing, facility owner/operator and agency interactive process incorporating CO2 AOR plume and pressure front computational modeling calibration, reporting, evaluation, and decision-making adjustments as necessary for protection of public health, safety, welfare, the environment and USDWs based on project surface/subsurface monitoring, additional/periodic well logging and pressure data, and other agency required/approved data submissions throughout the life of a project.

Pipelines Discussion

Based on information available to GEC in advance of completion of this report, pipeline transportation and delivery systems for supercritical CO2 appear to be the preferred, if not the only feasible means of transportation and delivery of supercritical CO2 to Class VI injection well facilities proposed in Allen Parish. It is plausible at this time to consider that pipeline systems will remain now and in the foreseeable future the preferred and most feasible means of transporting fluid CO2 material to any other potential Class VI projects in Allen Parish. Accordingly, pipeline transportation and delivery of supercritical CO2 will be an integral key and necessary component of any CO_2 Class VI sequestration project in Allen Parish with unique design and operation considerations for protection of public safety, health, and the environment. The following sections include assessment of potential pipeline system environmental and public health issues, regulatory control and mitigation measures, and risk evaluation.

Design Considerations

Supercritical CO_2 pipeline transportation systems must be designed and constructed in a manner that addresses a multitude of construction and performance standards and requirements, all necessary to ensure safe operations from the point of CO_2 source system entry, throughout transport, and destination exit/delivery. Both state LDENR and Federal Pipeline and Hazardous Material Safety Administration (PHMSA) regulations have specific design specifications found in 49 CFR Part 195 Subpart C. These design specifications are:

- Qualifying metallic components other than pipe,
- Design temperature,
- Variations in pressures between two pipeline components,
- Internal design pressure,
- External pressure,
- External loads,
- Fracture propagation,
- New and used pipe,
- Valves,
- Fittings,
- Passage of internal inspection devices,
- Fabricated branch connections,
- Closures,
- Flange connections,
- Design and construction of aboveground breakout tanks,
- Fabricated assemblies,
- Station piping, and
- Leak detection.

As one can see, state and federal regulations are highly prescriptive and regulated with regards to pipeline design specifications, thus system design flaw risks present are considered to be very low. It is worthy to note that PHMSA's pipeline safety regulations were last amended on April 29, 2024, incorporating the latest design specifications and updating the regulations for, in part, maintaining and improving protection of the environment and public safety.

Corrosion Issues

Contrary to the relatively low risk of failure of a pipeline system resulting in an environmental release due to design flaws, it is well documented that supercritical CO_2 fluid poses significant metal corrosivity risks including pipeline systems which, if not mitigated, could result in mechanical integrity failure and uncontrolled environmental release of CO_2.

Types of corrosion risks include external corrosion, internal corrosion, and corrosion due to interference currents. Each are further discussed below.

External Corrosion

External corrosion can have several detrimental effects on pipelines. The primary concern is thinning of the pipe wall, which can reduce the thickness of the pipe wall, weakening its structural integrity. This makes the pipeline more susceptible to ruptures and leaks.

Corroded pipelines also pose a significant safety risk, including the potential for sudden release of large volumes of CO_2 gas, which if near human population, could cause death due to asphyxiating surface conditions.

Internal Corrosion

Internal corrosion of a pipeline system is an issue that must be addressed by pipeline operators to prevent failures. For pipeline systems that transport supercritical carbon dioxide, internal corrosion is a significant issue that must be adequately addressed to prevent mechanical failure and potential environmental releases. At a minimum, pipeline system operators must investigate the corrosive effect of the carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.

If corrosion inhibitors are used to mitigate internal corrosion, the operator is required to:

- Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect,
- Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion, and
- Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding seven and one half (7.5) months.

Additionally, whenever pipe is removed from a pipeline, the internal surface of the pipe must be inspected for evidence of corrosion. If internal corrosion is found, the operator must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

Corrosion from Interference Currents

Pipeline interference currents are unwanted electrical currents that can affect pipelines, typically caused by nearby electrical systems. These currents can be either alternating current (AC) or direct current (DC) and can lead to various issues, including corrosion and safety hazards (Rizk and others, 2014).

AC interference often occurs when pipelines are in close proximity to high-voltage power lines. The electromagnetic fields generated by these power lines can induce AC voltages onto the pipeline, leading to induced AC currents. Factors such as the condition of the pipeline coating, soil composition, and distance from the power lines influence the magnitude of these currents.

DC interference can happen due to the interaction of cathodic protection systems, which are used to prevent corrosion on pipelines. If a pipeline's cathodic protection system inadvertently directs current onto a nearby foreign pipeline, it can cause corrosion at the point where the current exits the foreign pipeline.

Corrosion Mitigation

Corrosion risks are mitigated by the comprehensive and specific requirements of 49 CFR Part 195 Subpart H. These rules specify the methods to be employed to prevent external and internal corrosion of the pipeline and associated components.

External Coatings

Each buried or submerged pipeline must have an external coating for external corrosion control. Coating material for external corrosion control must:

- Be designed to mitigate corrosion of the buried or submerged pipeline,
- Have sufficient adhesion to the metal surface to prevent under film migration of moisture,
- Be sufficiently ductile to resist cracking,
- Have enough strength to resist damage due to handling and soil stress,
- Support any supplemental cathodic protection, and
- If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

Cathodic Protection

Each buried or submerged pipeline must have cathodic protection. The cathodic protection must be in operation not later than one year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable. All other buried or submerged pipelines that have an effective external coating must have cathodic protection.

Cathodic protection is a technique used to prevent the corrosion of metal surfaces by making them the cathode of an electrochemical cell. This is typically achieved by connecting the metal to be protected to a more easily corroded "sacrificial metal" that acts as the anode. The sacrificial metal corrodes instead of the protected metal, thereby preserving its integrity.

Cathodic protection by induced currents, often referred to as Impressed Current Cathodic Protection (ICCP), is another method used to prevent corrosion in metal structures by applying a controlled electrical current. ICCP systems use an external power source to provide a continuous electrical current to the metal structure that needs protection. This current is supplied through anodes, which are typically made of materials like titanium or mixed metal oxides (Payer and others).

Electrical Isolation

To mitigate interference currents, operators implement various measures, such as improving pipeline coatings, increasing separation distances, and using grounding techniques.

The operator must also electrically isolate each buried or submerged pipeline from other metallic structures, unless the operator electrically interconnects and cathodically protects the pipeline and the other structures as a single unit.

Operators must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. Each electrical isolation must be inspected and electrically tested to assure the isolation is adequate.

For pipelines exposed to stray currents, operators must have a program to identify, test for, and minimize the detrimental effects of such currents. Operators must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

Assessments

Pipeline system operators have both direct and indirect methods available for assessing the presence and/or undesirable effects of corrosion on system mechanical integrity to identify issues and mitigate with corrective actions necessary to prevent uncontrolled environmental releases from system failure.

Direct assessment means an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion, and stress corrosion cracking) to a pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post-assessment.

Operators of buried pipelines must follow the requirements of NACE SP0502 and develop and implement an External Corrosion Direct Assessment (ECDA) plan. In addition to the requirements in Section 3 of NACE SP0502 (incorporated by reference, see §195.3). The ECDA plan procedures for pre-assessment must include the following:

- Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment,
- The basis on which the selection is made of at least two different, but complementary, indirect assessment tools to assess each ECDA region, and
- If an indirect inspection method is utilized that is not described in Appendix A of NACE SP0502 (incorporated by reference, see § 195.3), the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

The use of smart pigs is also a method of pipeline direct assessment. Smart pigs, also known as in-line inspection (ILI) tools, are used to inspect the internal condition of pipelines. They travel through the pipeline and use various sensors to detect anomalies such as corrosion, cracks, and other defects.

Pipeline indirect assessment is a crucial phase in pipeline integrity management. It involves using various aboveground inspection tools to gather data about the pipeline's condition without directly accessing it. This method helps identify areas that are most susceptible to issues like external corrosion or coating damage. Some key points about indirect assessment are provided below.

- Data Collection: Tools such as pipeline current mappers (PCM) and sub-meter accurate GPS are used to collect data on the pipeline's depth, elevation profile, and other relevant parameters.
- Analysis: The collected data is analyzed to predict potential problem areas, such as spots where corrosion or environmental cracking might occur.
- Complementary Tools: At least two complementary inspection tools are typically used to confirm the most susceptible locations.
- Direct Examination: Based on the indirect assessment, specific sites are selected for direct examination, where the pipeline is excavated and inspected directly.

Mitigation of internal corrosion is also a critical concern to pipeline operators as it can cause reduced transmission flowrates. The identification and mitigation of pipeline corrosion has been thoroughly addressed in 49 CFR Part 195 Subpart H. The pipelines will be closely inspected and monitored either by direct or indirect assessments, or both. Therefore, the corrosion risks will pose a low risk if monitored properly.

Injection Well Facility Pipeline System Operations Risks

Operators are required to monitor the injection well and the geologic sequestration project to confirm that the well, facility and pipeline are functioning properly. Continuous recording devices must be installed, used, and maintained in proper working order for each well. Continuous recording devices will monitor:

- surface injection or bottom-hole pressure,
- flow rate, volume and/or mass, and temperature of the carbon dioxide stream,
- tubing-casing annulus pressure and annulus fluid volume, and
- any other data specified by the commissioner.

It is very important that facility operators adhere to the authorized wellhead pressures and corresponding injection rates. Close monitoring of the pressures and injection rates is needed since rates and pressures are inputs in the modeling of the plume size and pressure front induced as result of the CO2 injection.

Operations risks also involve what is commonly referred to as the human factor. This can involve incidents resulting from human error during normal operations and/or routine maintenance. For example, accidental environmental releases can occur by failing to close a valve during a startup, applying system pressures that exceed permitted maximums, and other errors or omissions. However, operational risks can be mitigated through proper training of operations personnel with frequent refresher courses and running simulated emergency responses to a specific failure.

Third Party Risks

Third party risks are one of the greater potential risks when it comes to pipeline safety. It is the risk over which the operator has the least control and is the most difficult to anticipate. Third party risks can range from intentional acts of vandalism to accidents caused by the careless operation of machinery. Excavations by third parties in the vicinity of the pipeline without having the operator mark the location of the pipeline is another hazard.

However, third party risks can be mitigated with use of strategies such as those bulleted below.

- Installation of protective barriers around wellheads, piping, and above ground structures that may be vulnerable to physical or accidental damage by mobile equipment or trespassers.
- Providing for site security such as enclosing the area with fencing.
- Installation of cameras or other surveillance equipment that will allow operators to observe the facility when on duty and at all times.
- Encouraging the public to call 811, which is the national call-before-you-dig phone number. Anyone who plans to dig should call 811 or go to their state 811 center's website before digging to request that the exact location of buried utilities be marked with paint or flags.
- Keep first responders educated on facility operations and any hazards they may encounter (i.e., stored chemicals on site) should the need arise to respond to an emergency.
- Promote public awareness at appropriate public events.

The measures listed above are just some of the actions that may be employed to mitigate third party risks. However, it remains difficult to anticipate all third-party risks that may happen.

Pipelines Environmental and Public Health Risk Evaluation

Although supercritical CO2 pipeline transmission has been regulated under the authority of PHMSA with implementation and enforcement of 49 CFR Part 195 hazardous liquids pipeline requirements for well over 30 years effective July 12, 1991, a simple internet search on the topic of CO2 pipeline transmission today shows continued, if not heightened public interest on the safety of CO2 pipeline transmission operations. One can find today on the internet related discussion on CO2 pipeline transmission, including comments addressed and presumably previously submitted to PHMSA on environmental release dispersion modeling, in-line odorants, pipe ductile fracturing, CO2 stream contaminants, and existing line conversion to CO2, among others.

GEC respects PHMSA's public trust, duties, and responsibilities to ensure public safety and environmental protection pursuant to implementation of their statutory authority including past and ongoing rulemaking and public participation processes to address public safety and environmental protection specifically for supercritical CO_2 pipeline transmission. As such, it is expected that PHMSA has and will continue to duly consider and vet all substantive and relevant public comments submitted to their agency, and with sound and objective scientific basis within their authority, has taken and will continue to take in due time the necessary and appropriate actions to adequately address the same to ensure protection of public safety and the environment. The following three paragraphs are presented in support of this position.

PHMSA

In its most recent amendment to 49 CFR 195 with the final rule published on April 21, 2024, PHMSA evaluated comments received during the rule-making process and acknowledged the following general environmental consequences due to transmission of hazardous liquids, including supercritical CO_2.

"The release of hazardous liquids (as well as carbon dioxide) or gas can cause the loss of cultural and historical resources (e.g., properties listed on the National Register of Historic Places); biological and ecological resources (e.g., coastal zones, wetlands, plant and animal species and their habitats, forests, grasslands, or offshore marine ecosystems); special ecological resources (e.g., threatened and endangered plant and animal species and their habitats, national and State parklands, biological reserves, or wild and scenic rivers); and the contamination of air, water resources (e.g., oceans, streams, or lakes), and soil that exists directly adjacent to and within the vicinity of pipelines. Incidents involving pipelines can result in fires and explosions, causing damage to the local environment. Depending on the size of a spill, carbon dioxide release, or gas leak, and the nature of the failure zone, the potential impacts could vary from property or environmental damage, to injuries or, on rare occasions, fatalities."

In consideration and mitigation of these potential environmental impacts and public safety issues, PHMSA responsibilities include implementation and enforcement of the Federal pipeline regulations structured as "a risk-management system that is <u>prevention-oriented and focused on identifying safety hazards and reducing the likelihood and quantity of a</u> gas or hazardous liquid (or <u>carbon dioxide</u>) <u>release</u>." Pursuant to the underlined objective, PHMSA regulations require pipeline operators to develop and implement integrity management (IM) programs "to enhance safety by identifying and reducing pipeline integrity risks." Further, in developing regulations, PHMSA notes that "staff actively participates in the standards development process to ensure that each incorporated standard will enhance pipeline safety and environmental protection." In holistic summary, PHMSA further states that compliance with the pipeline safety regulations (PSRs) "substantially reduces the possibility of an accidental release of product."

Key Regulatory Preventative Measures

PHMSA's hazardous liquid CO_2 pipeline safety requirements are developed and designed for the safe transmission of CO_2, including utilization for transportation to Class VI injection well

CO_2 sequestration projects as further detailed with key points and preventative measures summarized below.

Supercritical Carbon Dioxide

During Class VI CO_2 sequestration operations, CO_2 will be transported in pipelines to the injection well for injection into subsurface geological formations that have been approved for sequestration in what is known as the supercritical state.

A supercritical state occurs when a substance is at a temperature and pressure above its critical point, where distinct liquid and gas phases do not exist. In this state, the substance exhibits properties that are intermediate between those of gases and liquids. For example, it can flow through materials like a gas but dissolve substances like a liquid (Chemistry Learner, 2024).

The critical pressure and temperature of CO_2 are key points where CO_2 can exist as both a liquid and a gas. Specifically, the critical temperature is 31.0°C (87.8°F) and the critical pressure is 73.8 atm (1071.6 psi or 7.38 MPa).

The pipeline line pressure will be maintained at a pressure above 1071.6 psi in order to keep the CO_2 in a supercritical state. The formation pore pressure in a normally pressured reservoir will occur at a depth of 2,305 feet. Therefore, the formations selected for CO_2 sequestration must at a minimum be deeper than this depth. Additionally, the temperature of a geological formation at this depth will be approximately 102 degrees Fahrenheit, which will be above the critical temperature of 87.8°F.

CO2 Pipeline Construction Materials

CO_2 pipelines are typically constructed using various alloys of steel to ensure durability and resistance to corrosion. Carbon steel is often used for CO_2 pipelines, especially in dry conditions, as pure, dry CO_2 is non-corrosive to carbon steels. Corrosion Resistant Alloys (CRAs) are recommended for environments where CO_2 is wet or contains impurities. Examples include Martensitic Stainless Steels which are typically 13% chromium (Cr) steels and Austenitic Stainless Steels such as 316L, 904L, and 6Mo Austenitic stainless steels (Craig and others, 2023).

Other types of pipe may be used under the PHMSA CO_2 pipeline regulations. One option is the use of glass reinforced epoxy (GRE) lined tubing comprised of an internal fiberglass liner bonded to the inside of a steel pipe, which is used for some CO_2 pipelines. Epoxy-coated and polyethylene-lined carbon steel pipes are also options.

The requirements for CO_2 pipelines made of materials other than steel are addressed in 49 CFR §195.8. It states that no person may transport any hazardous liquid or carbon dioxide through a pipe that is constructed after October 1, 1970, for hazardous liquids or after July 12, 1991, for carbon dioxide of material other than steel unless the person has notified the Administrator in writing at least 90 days before the transportation is to begin. Notification details include whether carbon dioxide or a hazardous liquid will be transported and the chemical name, common name, properties, and characteristics of the substance to be transported, and the material used in the construction of the pipeline. These requirements ensure that PHMSA is informed and can assess the safety and suitability of the materials used.

It is important to consider the specific conditions of the CO_2 transport, such as pressure, temperature, and impurities, when selecting the appropriate pipeline material. For detailed guidance, consulting with material experts or industry standards like those from the American Petroleum Institute (API) is advisable.

Leak Detection

A CO_2 pipeline must have an effective system for detecting leaks in accordance with 49 CFR §195.134 or §195.452, as appropriate. An operator must evaluate the capability of its leak detection system to protect the public, property, and the environment and modify it as necessary to do so. At a minimum, an operator's evaluation must consider the following factors including length and size of the pipeline, type of product carried, the swiftness of leak detection, location of nearest response personnel, and leak history.

The requirement for pipeline operators to use Computation Pipeline Monitoring (CPM) is another enhancement added to the regulations. CPM is a software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating anomaly that may be indicative of a commodity release.

Each CPM leak detection system installed on a hazardous liquid pipeline must comply with API RP 1130 in operating, maintaining, testing, recordkeeping, and dispatcher training of the system. Pipelines constructed prior to October 1, 2019, are required to have a leak detection system that complies with the requirements in §195.444 by October 1, 2024. Pipelines constructed on or after October 1, 2019, were required to have a leak detection system that complies with the requirements in §195.444 by October 1, 2020.

Pipeline Integrity Management Plan

The requirements for a Pipeline Integrity Management Plan under 49 CFR Part 195 are detailed in section 195.452. The pipeline safety regulations require operators to have a written Pipeline Integrity Management Plan. This plan is a critical component of the safety requirements and includes the components outlined below.

- Risk Assessment: Identifying potential threats to pipeline integrity and assessing the risks associated with them.
- Preventive and Mitigative Measures: Developing and implementing measures to prevent pipeline failures and to mitigate the consequences of such failures.
- Performance Monitoring: Continuously monitoring the performance of the pipeline and the effectiveness of the integrity management program.

- Remediation: Addressing any anomalies or defects detected in the pipeline system in a timely manner.
- Management of Change: Ensuring that any changes in operations, conditions, or regulations are accounted for in the integrity management plan.
- Training and Qualifications: Providing appropriate training to personnel involved in the integrity management program and ensuring they are qualified to carry out their duties.
- Record Keeping: Maintaining comprehensive records of all activities related to pipeline integrity management.

The provision for risk-based assessments in 49 CFR Part 195 can be found in Appendix B to Part 1951. This appendix provides guidance on how a risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines is allowed by §195.3031. It establishes test priorities for older pipelines, not previously pressure tested, based on the inherent risk of a given pipeline segment.

Additionally, §195.452 (f) and (i) require an operator to include a process in its integrity management program for identifying which pipeline segments could affect a high consequence area and to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area.

High consequence areas include certain waterways and populated/sensitive areas as defined below.

- A commercially navigable waterway, which means a waterway where a substantial likelihood of commercial navigation exists.

- A high population area, which means an urbanized area, as defined and delineated by the Census Bureau that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.

- An other populated area, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

- An unusually sensitive area, as defined in §195.6., including a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

Integrity assessments are to be conducted on a schedule based on the risk that the pipeline facility poses to the high consequence area in which the pipeline facility is located.

Rupture-Mitigation Valve (RMV) is an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of hazardous liquid or carbon dioxide released from the pipeline and to mitigate the consequences of a rupture.

Additionally, operators must conduct a post-failure or post-accident analysis if a failure involves the closure of a rupture-mitigation valve (RMV) or alternative equivalent technology. This analysis should identify factors that may have impacted the release volume and consequences, and outline measures to minimize the consequences of a future failure or accident.

For CO2 pipelines, the American Petroleum Institute (API) provides a tactical guidance document that outlines best practices for preparedness and initial response to a pipeline release of CO2.

Valve Spacing

The valve spacing requirements for CO2 pipelines are quite specific. According to the regulations set by PHMSA, for newly constructed or entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments installed after April 10, 2023, the valve spacing must not exceed 15 miles for pipeline segments that could affect or are in High Consequence Areas (HCAs), and 20 miles for pipeline segments that could not affect HCAs. However, a maximum distance is not to exceed 7½ miles from the endpoints of the HCA segment or the segment that could affect an HCA.

Control Rooms

49 CFR 195.446 requires operators of pipeline facilities to have a control room if they use controllers to monitor and control the pipeline through a SCADA (Supervisory Control and Data Acquisition) system. This regulation mandates that operators must have written control room management procedures that cover various aspects, including the roles and responsibilities of controllers during normal, abnormal, and emergency conditions.

Control systems for components on carbon dioxide pipelines must have a fail-safe design where practical from good engineering practice. A safe condition must be maintained until personnel take appropriate action either to reactivate the component served or to prevent a hazard from occurring.

Electrical control systems, means of communication, emergency lighting, and firefighting systems must have at least two sources of power, which function so that failure of one source does not affect the capability of the other source.

Sudden Environmental Release

The LDENR and PHMSA supercritical CO2 pipeline system standards and regulations are designed to ensure safe pipeline installations and supercritical CO2 fluid transmission operations when applied and implemented to the fullest extent by the regulated community. However, as further discussed below, real potential for a sudden environmental release of supercritical CO2, for whatever reason, from pipeline transmission operations exists.

The consequences of CO2 pipeline failures can differ widely because of differences in release rates and volumes of CO2, the dispersion characteristics of a release, and the environmental setting at the point of release and adjacent impacted area. Release volumes can depend on factors such as leak or rupture size, flow rate through the pipeline, the time required to detect the leak or rupture, the effect and timing of operator actions, the locations of isolation valves and / or Rupture Mitigating Valves, and the elevation profile of the pipeline. The dispersion characteristics are highly dependent on location and environmental conditions including temperature, humidity, wind speed and direction, local topography, and other factors that could affect the ability of CO2 to migrate. Environmental surface settings may vary from very remote rural unpopulated locations with little to no environmentally sensitive area to HCA locations with environmentally sensitive areas.

Pipelines Risk Categorization and Ranking

Based on review of available published literature on supercritical CO2 pipeline transmission, applicable and relevant PHMSA and LDENR hazardous liquids pipeline transmission regulations, surface and shallow subsurface conditions of Allen Parish, and discussions with industry representatives, GEC summarizes supercritical CO2 pipeline system environmental / public health risks with the general categories and qualitative ranking from highest (1) to lowest (6) listed below.

1) Operator (Human) Error
2) Third-Party Incident
3) Corrosion Induced Equipment Failure
4) Faulty Material / Equipment / Weld Failure
5) Design Flaw
6) Acts of God / Force Majeure / Natural Disasters (Meteorological, Geological, Climatic)

An example of a Category 6 CO2 pipeline release is the Satartia, Mississippi rupture of the Denbury Delta Pipeline on February 22, 2020. A landslide slope failure following extended heavy rainfall caused the subgrade soils to move downslope and resulted in a full circumferential girth weld failure. The pipeline rupture released an estimated total of 31,405 barrels of CO2.

On April 3, 2024, the Denbury Green Pipeline at the Sulphur, Louisiana Lake Charles Pump Station had a release of CO2 related to failure of surface facilities at the pump station. This release was an example of a Category 4 or 5 failure.

As previously stated above, it is GEC's belief that the LDENR and PHMSA supercritical CO2 pipeline system standards and regulations are adequate when applied and implemented to the fullest extent by the regulated community ensuring safe pipeline installations and supercritical CO2 fluid transmission operations.

Although there may be other scenarios not ranked above which could possibly occur to pose environmental or public health risks resulting from environmental release of CO_2 by way of pipelines, the ranked scenarios in the list above represent GEC's knowledge and understanding of regional subsurface conditions, published scientific research and literature, and applied reasonable risks contemplated under the current PHMSA and LDENR regulatory standards and requirements promulgated for supercritical CO_2 pipeline transmission systems.

SECTION 5: Application to Allen Parish Proposed Projects

Allen Parish has favorable geologic conditions for CO2 sequestration. Potential CO2 sequestration reservoirs between the base of the USDW and the top of overpressured conditions include:

- Miocene sands
- Anahuac Group sands
- Frio Formation sands
- Cockfield Formation sands
- Wilcox Group sands

The potential depth range for CO2 sequestration reservoirs is from approximately 3,000 feet to over 14,000 feet in the northern part of Allen Parish to approximately 3,000 feet to 11,000 feet depth in the southern part of Allen Parish.

The regional structure of Allen Parish is relatively simple with generally uniform southward dip of the sedimentary formations and minor occurrence of faulting.

Allen Parish is close to large industrial emitters of CO2 in southwest and south Louisiana. In addition, the ExxonMobil (formerly Denbury) interstate CO2 pipeline (Green Pipeline) is located in the southern part of Allen Parish.

Allen Parish has been well-characterized by petroleum exploration that has been conducted for over 100 years. A large number of petroleum test wells has been drilled and the geophysical logs and other data from these wells are available. In addition, two-dimensional seismic surveys have been conducted at close intervals across Allen Parish and several large three-dimensional seismic surveys have been run.

Allen Parish Police Jury informed GEC that CO2 sequestration projects are being planned in Allen Parish. These include the Magnolia sequestration project planned by Oxy Low Carbon Ventures, LLC and the Hummingbird and Mockingbird CO2 sequestration projects planned by ExxonMobil Low Carbon Solutions Onshore Storage, LLC. In addition, a Denbury Carbon Solutions LLC (acquired by ExxonMobil in 2024) CO2 sequestration project has been planned in southern Vernon Parish to the northwest of Allen Parish. This project is called the Draco CO2 sequestration project.

GEC met with representatives of Oxy Low Carbon Ventures, LLC (Oxy) on August 13, 2024 and with representatives of ExxonMobil Low Carbon Solutions Onshore Storage, LLC (ExxonMobil) on August 22, 2024, to obtain information about the planned CO2 sequestration projects. The meetings with GEC provided summaries of major components of the project plans. GEC, however, has not received copies of permit applications or other documentation concerning these projects from Oxy or ExxonMobil. GEC has submitted public information requests to the LDENR, but has not received information. This is a significant limitation for evaluating risks specific to these projects.

GEC has received copies of lease agreements by Oxy and by ExxonMobil with surface owners of properties in the areas of the planned projects. **Figure 5-1** shows the approximate areas of the leases for the Oxy and ExxonMobil projects.

OXY MAGNOLIA CO2 SEQUESTRATION PROJECT

The proposed Magnolia project is to be located in the north-central portion of Allen Parish to the northwest of Oberlin, Louisiana. Oxy has leased 26,824.80 acres from timber land companies in a contiguous area located in the following townships:

- T. 2 S., R. 5 W.
- T. 2 S., R. 4 W.
- T. 3 S., R. 5 W.
- T. 3 S., R. 4 W.
- T. 4 S., R. 5 W.
- T. 4 S., R. 4 W.

The lease area extends approximately 13 miles from north to south. At the north and south ends, the lease area is 4 miles wide. The central part of the lease area is 7 miles wide. The lease area overlaps with the West Bay Wildlife Management Area.

The lease specifies that the CO2 sequestration interval extends from the top of the Lower Miocene to the base of the Vicksburg Group. In the southern part of the lease area, the sequestration zone is the depth interval from 3,306 feet to 6,820 feet as shown in the geophysical logs of well serial number 238172. Oxy stated that the planned injection wells will be in the Lower Frio Formation.

Oxy submitted two Class VI UIC permit applications to the U.S. EPA in 2021 for the first two injection wells. The plans are for the wells to inject 2 Mt per year of CO2 for a period of 15 years. The permit applications were transferred to the LDENR when Louisiana was granted primacy for the Class VI UIC program in 2024. Oxy received a Notice of Deficiencies letter containing review comments on the permit applications from the LDENR in August 2024.

Oxy also submitted a Class V UIC permit application to the LDENR for a stratigraphic test well. This well (Serial Number 975950) was drilled and tested in November-December 2022.

Oxy stated that a source of CO2 for the Magnolia project has not been established, but that industrial sources will be used.

Oxy stated that an environmental risk assessment for the Magnolia project will be conducted during 2025 by Pacific Northwest National Laboratory under a grant from the U.S. Department of Energy.

EXXONMOBIL HUMMINGBIRD AND MOCKINGBIRD CO2 SEQUESTRATION PROJECTS

The Hummingbird and Mockingbird projects are to be located in the southern part of Allen Parish to the west and southeast of Oberlin, Louisiana.

ExxonMobil has leased 32,653 acres from timberland companies in two non-contiguous area located in the following townships:

- T. 4 S., R. 6 W.
- T. 4 S., R. 5 W.
- T. 4 S., R. 4 W.

- T. 4 S., R. 3 W.
- T. 5 S., R. 6 W.
- T. 5 S., R. 5 W.
- T. 5 S., R. 4 W.
- T. 5 S., R. 3 W.
- T. 6 S., R. 4 W.
- T. 6 S., R. 3 W

The Hummingbird lease area is located on the south side of the Oxy lease and extends westward into Beauregard Parish and eastward north of Oberlin. The Mockingbird lease area is southeast of Oberlin. The ExxonMobil lease areas have numerous gaps that are currently being acquired. The boundaries as shown in Figure 5-1 are approximate and are enveloping outside boundaries of the actual leased properties. The extent of any additional property leasing is not known at this time.

ExxonMobil is developing plans for these projects. ExxonMobil plans to use CO2 from the former Denbury Green Pipeline, which extends from east to west through the southern part of Allen Parish.

ExxonMobil has submitted two Class V UIC permit applications to the LDENR for drilling of two stratigraphic test wells.

At the present time, Exxon anticipates that the CO2 injection will be proposed to be in the Frio Formation.

The ExxonMobil representatives briefly discussed the former Denbury Draco project to be located in Vernon Parish. The proposed injection interval would be in the Wilcox Group. Based on results of the stratigraphic test well for this project (Serial Number 976118), ExxonMobil stated that this project would not be economically viable.

SECTION 6 -- Risk / Benefit Evaluation

The development of CO_2 sequestration projects in Allen Parish presents risks and benefits for Allen Parish and its populace. Based on the suitable geologic conditions and proximity to sources of CO_2, the potential for long-term development and operations of CO_2 sequestration projects in Allen Parish could be significant and much larger than the proposed Oxy and ExxonMobil projects.

The economic benefits were evaluated by the H.C. Drew Center for Business and Economic Analysis at McNeese State University for the Oxy Magnolia Sequestration Hub project in November 2024. The McNeese study found that economic benefits included employment labor income, fiscal impacts, and lease payments to landowners. McNeese found that over a 12-year lifetime of the project, over $81 million in labor income would be created in Allen Parish. This would include construction jobs during a 2-year period and operations staff during a 10-year operating period. Real GDP in Allen Parish would increase by approximately $103 million.

The fiscal impact for Allen Parish would include $3.5 million to $4.4 million in tax collections during 2026 through 2035.

In addition, lease payments for surface rights and pore space use have been agreed with landowners. McNeese points out that these payment amounts are confidential but can be assumed to be substantial. These benefits would increase the overall economic and fiscal benefits.

Additional lease income could be generated by future seismic data acquisition and Class V test drilling.

The ExxonMobil projects were not included in the economic analysis. Based on potential areas of the ExxonMobil projects, it is possible that the economic impact would be larger than that related to the Oxy project. The ExxonMobil leased areas to date are similar in area to the Oxy project, but the infill leasing would increase the leased area significantly.

Based on the favorable geologic conditions, additional operators could be attracted to Allen Parish. As the relevant subsurface data is acquired and as progress is achieved by Oxy and ExxonMobil, leasing of adjoining areas and other parts of Allen Parish could expand significantly. In addition, the CO_2 sequestration projects could operate for extended periods of time based on the high potential storage capacity of the original targeted formations as well as other portions of the subsurface.

The implementation of CO_2 sequestration projects is accompanied by risks as discussed in Section 4 of this report. A principal goal of the regulatory structure for the Class VI UIC program has been identification and control of potential risks and Section 3 of this report has presented the regulatory program in detail.

The highest probabilities for releases of CO_2 are related to wells in the subsurface storage reservoir and from supercritical CO_2 pipeline distribution systems. Potential releases from subsurface containment are most likely related to wells that intersect the sequestration zone.

These include oil and gas exploration and production drill holes and wells and CO2-project related injection wells and monitoring wells. The regulatory requirements for identifying wells and implementing remedial actions are comprehensive and significant (Sections 3 and 4). It is possible that CO2 sequestration operators will develop projects in areas with fewer existing oil and gas wells in order to minimize this risk and the expense it poses to their projects.

Potential releases from CO2 pipelines can have a range of causes. The supercritical CO2 pipeline standards and regulations are designed to ensure safe pipeline installations and transmission operations, but there is potential for environmental releases.
It is recommended that Allen Parish communicate with the state and with operators to ensure that all regulatory requirements are met for addressing subsurface containment risk and CO2 transmission pipelines safety and risk minimization. Allen Parish could implement local ordinances to enhance requirements for testing and monitoring, periodic reporting and notifications, automatic shutoff equipment, and emergency and remedial response to ensure that any potential releases would be minimized and controlled.

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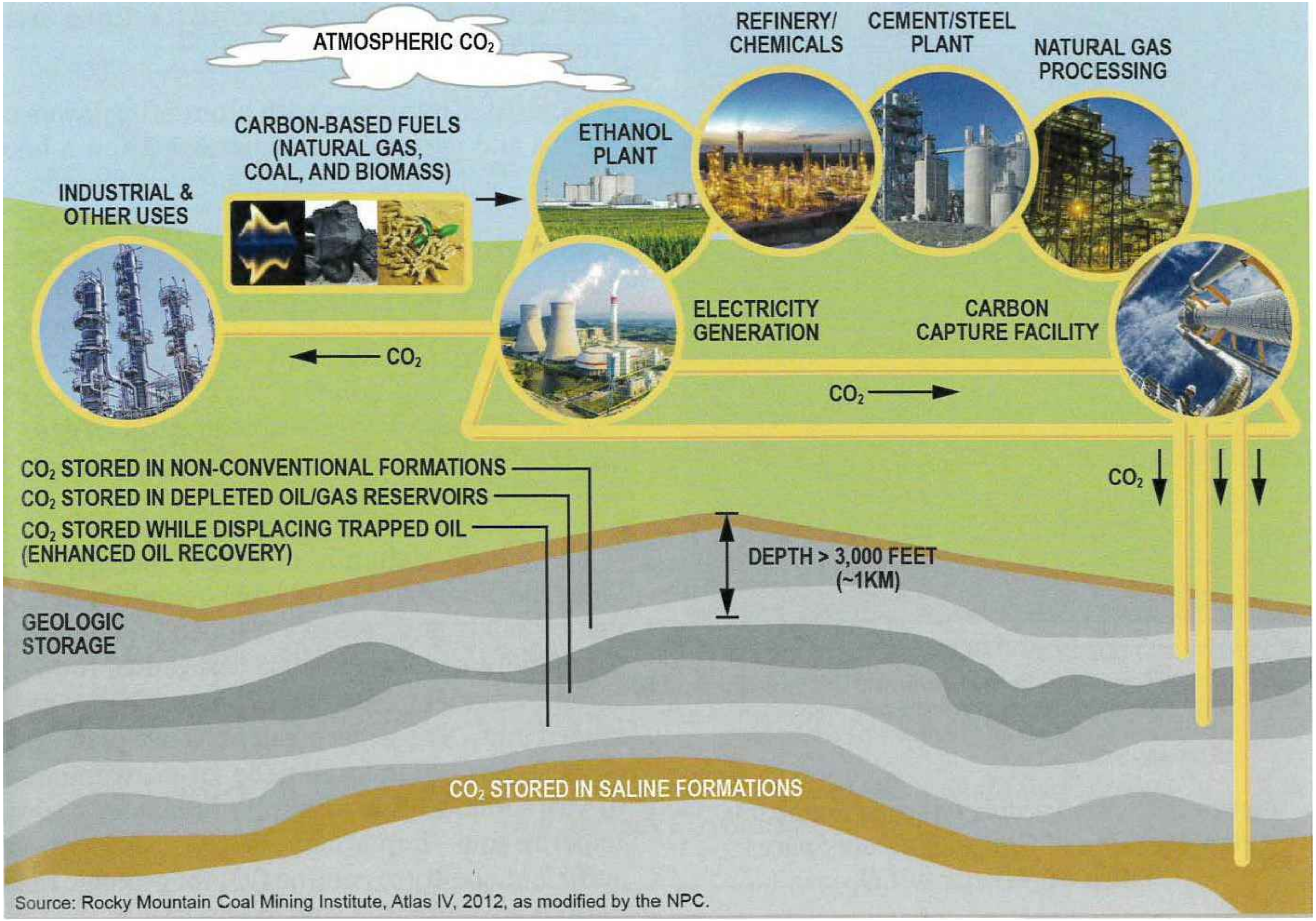
FIGURES



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Reference:
National Petroleum Council
2019, (Figure 7–1)

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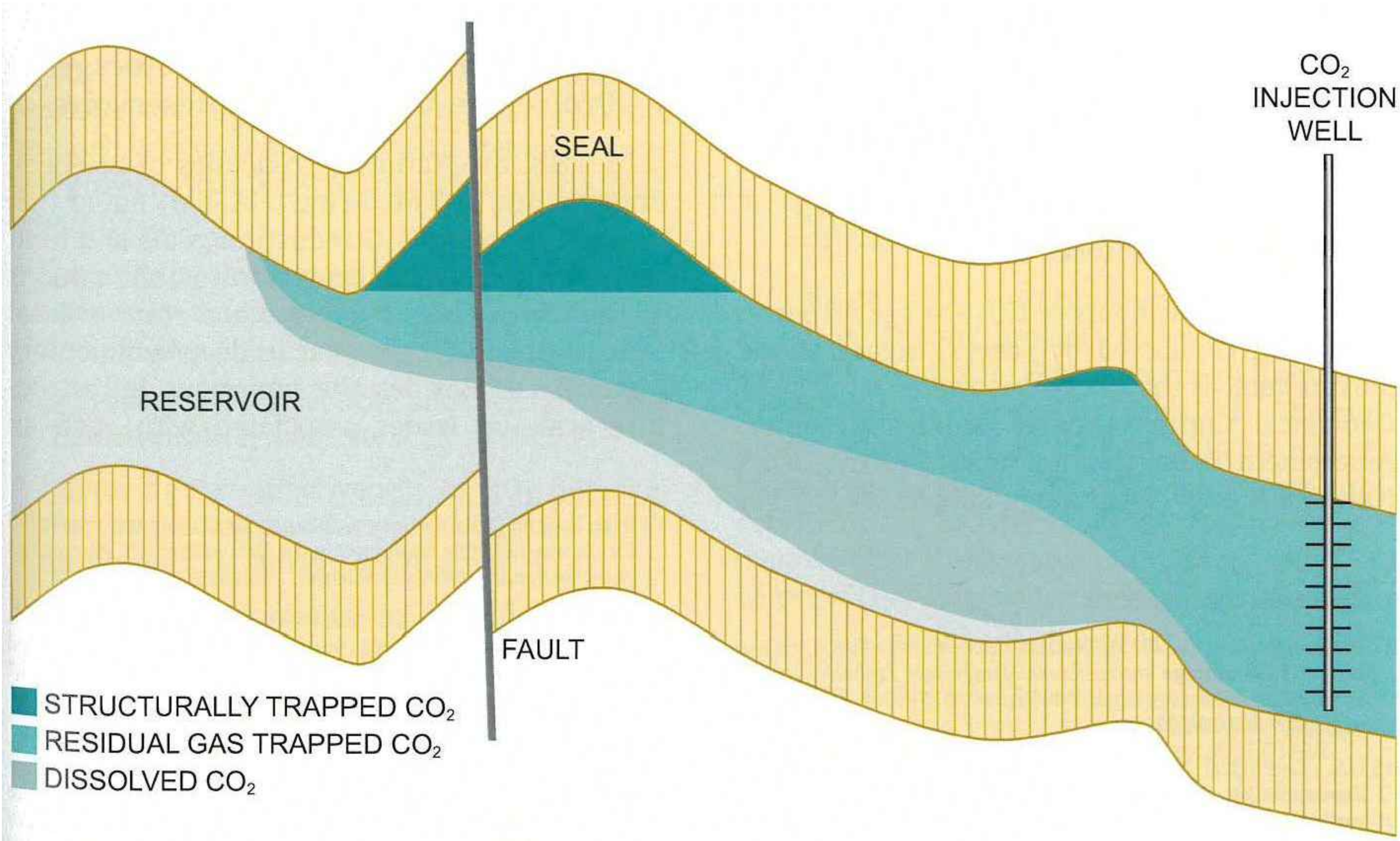
SCHEMATIC DIAGRAM OF TYPES OF CO2 SEQUESTRATION RESERVOIRS	FIGURE 1–1
	SCALE: N.T.S.
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 1–5.dwg



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Reference:
National Petroleum Council
2019, (Figure 7-4)

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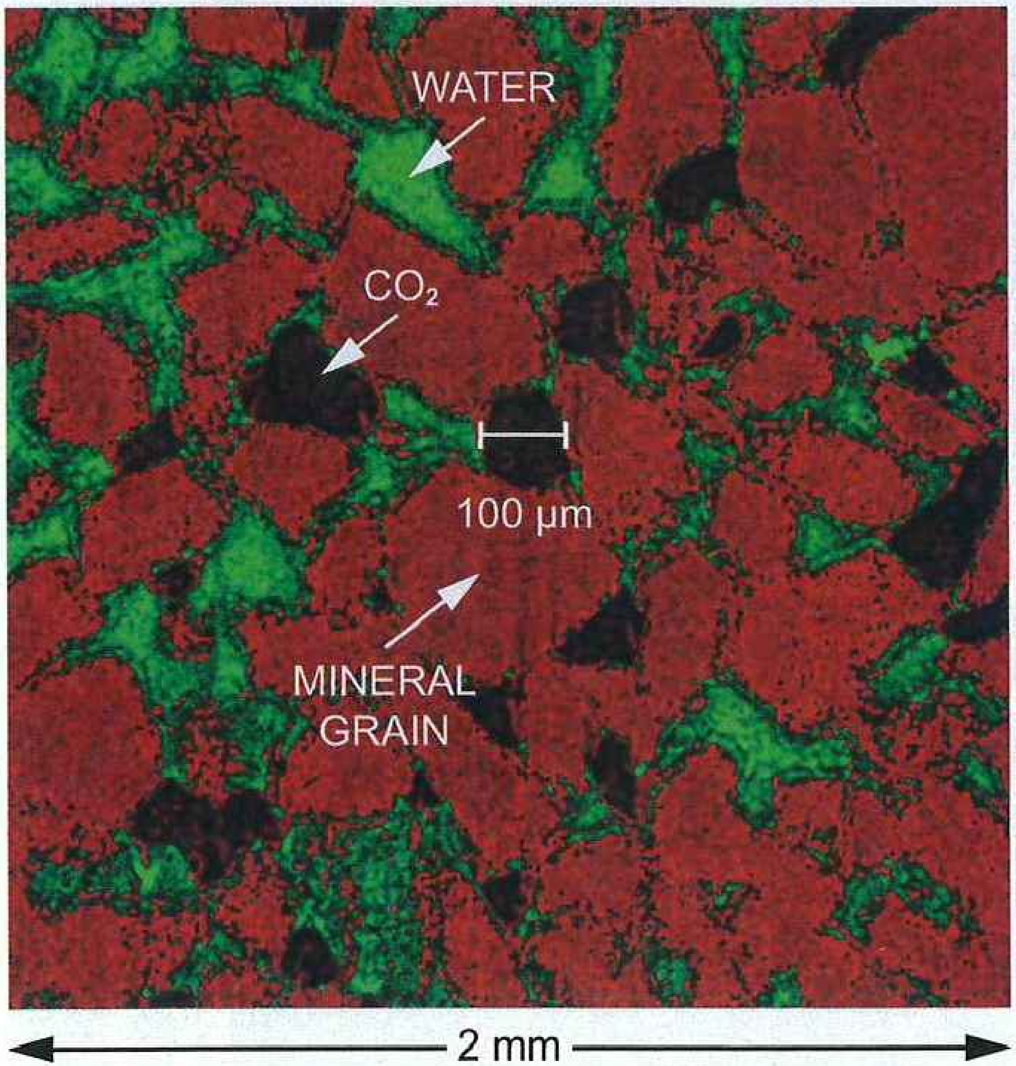
SUMMARY OF CO2 TRAPPING MECHANISMS	FIGURE 1-2
	SCALE: N.T.S.
	DATE: JAN. 2025



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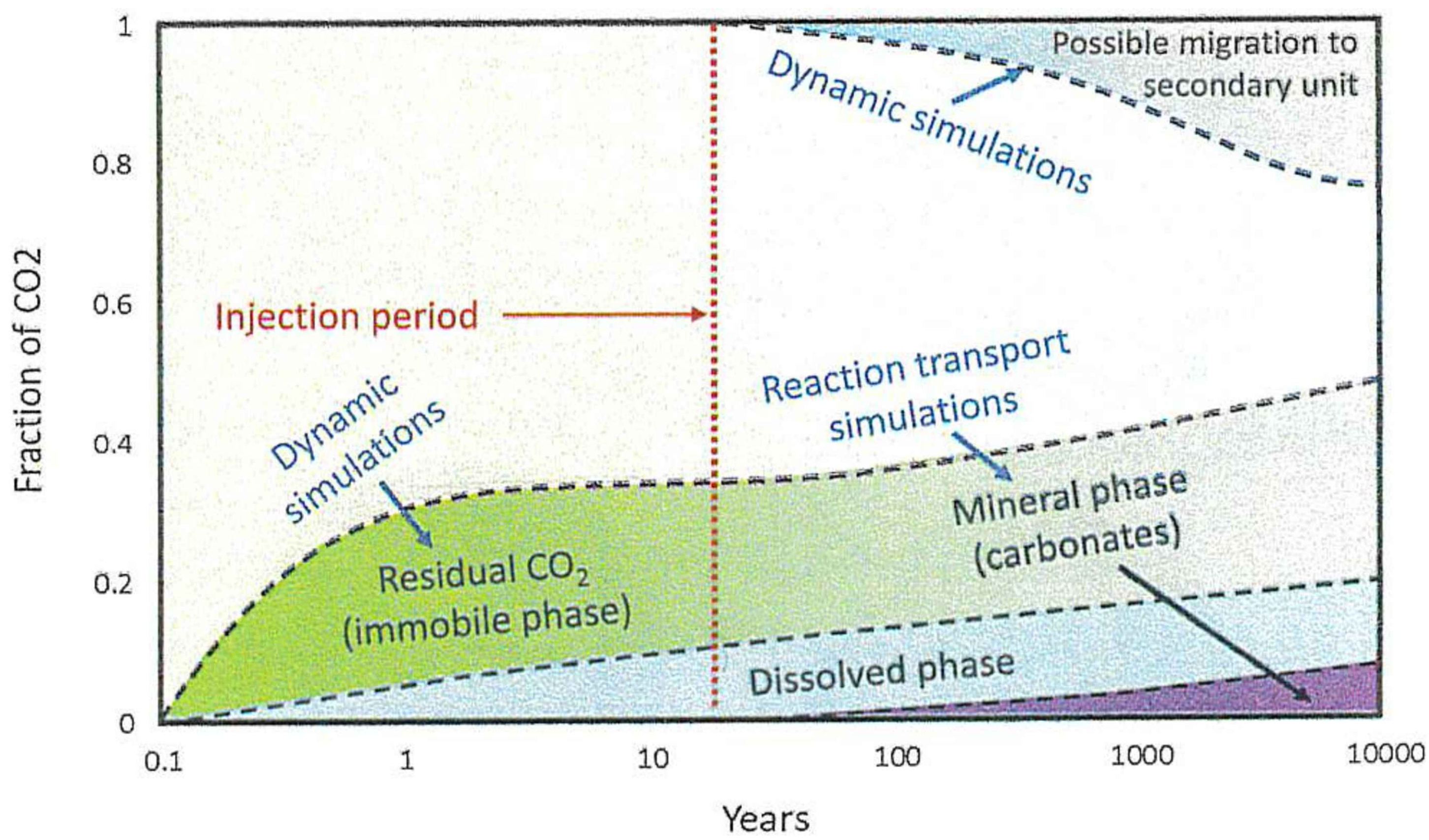
CAPILLARY TRAPPING OF CO2 IN PORE SPACES

FIGURE 1–3	
SCALE: N.T.S.	
DATE: JAN. 2025	

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 1–5.dwg



Source:
Ringrose, 2023

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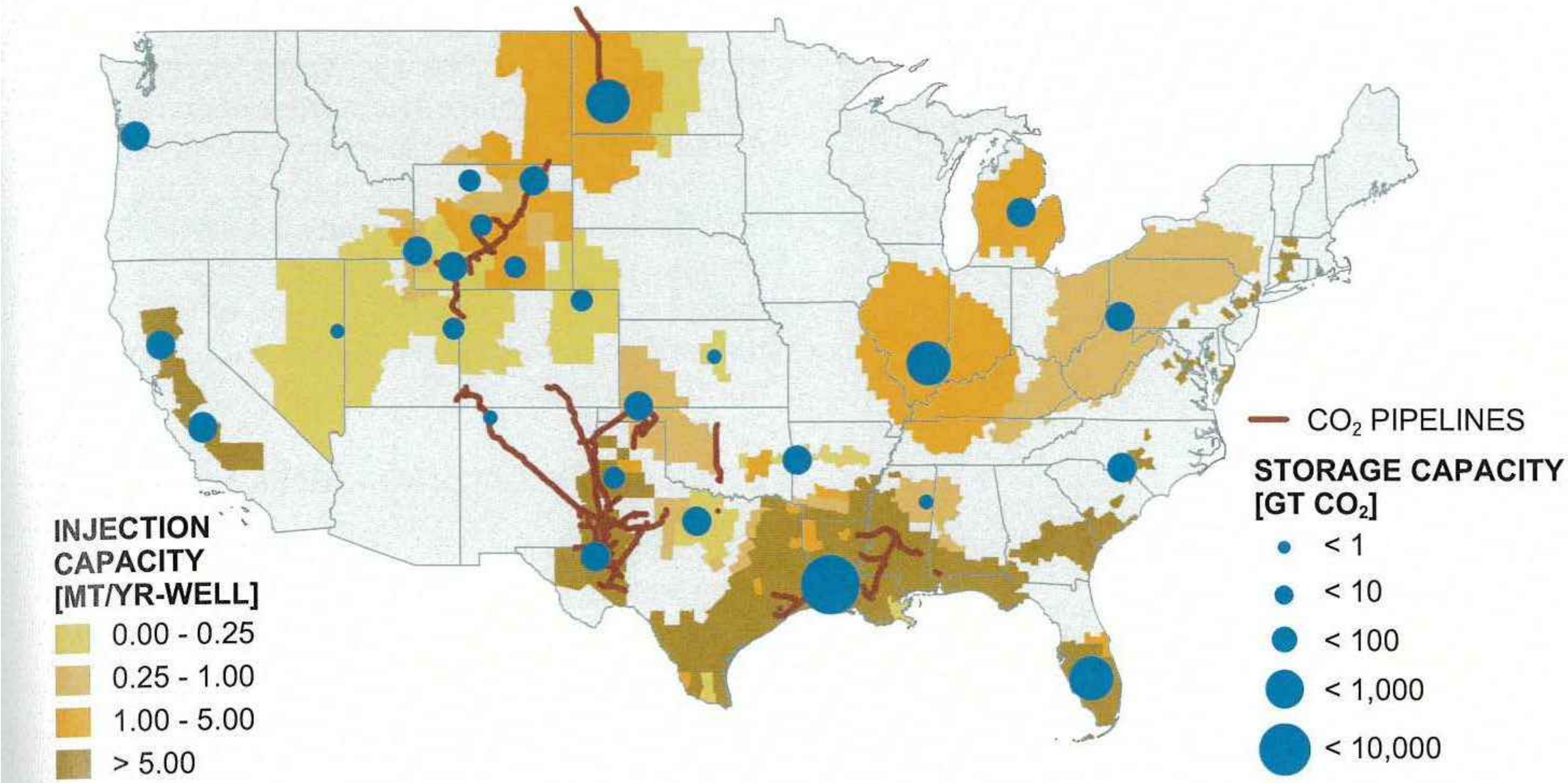
CONCEPTUAL DISTRIBUTION OF CO2 TRAPPING MECHANISIMS	FIGURE 1–4
	SCALE: N.T.S.
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 1–5.dwg



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

Reference:
National Petroleum Council
2019, (Figure 7–5)

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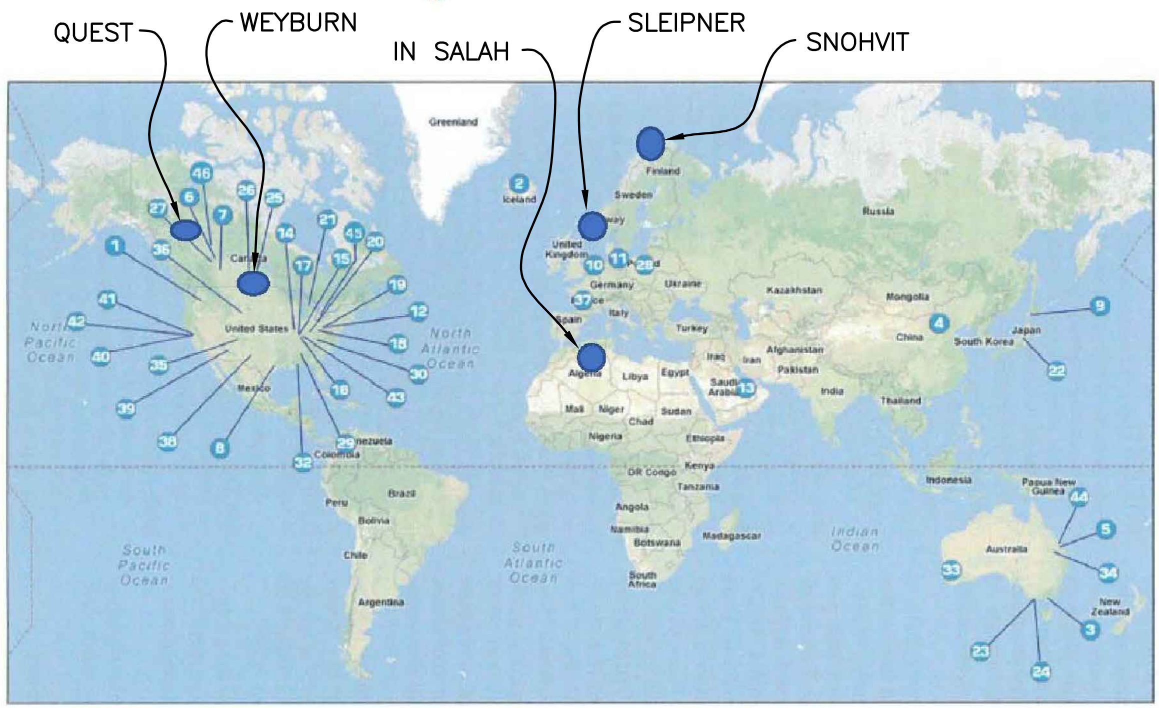
ESTIMATED CO2 STORAGE CAPACITY IN THE US	FIGURE 1–5
	SCALE: N.T.S.
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 1–5.dwg

CO2 Sequestration Projects

MAJOR PROJECTS

Sleipner, Norway
Snohvit, Norway
In Salah, Algeria
Weyburn, Canada
Quest, Canada



1 BSCSP Basalt	16 MGSC Sugar Creek EOR Phase II	32 SECARB - Mississippi Saline Reservoir Test Phase II
2 Carbfix	17 MGSC Tanquary ECBM Phase II	33 South West Hub (Collie South West Hub)
3 CarbonNet	18 Mountaineer PVF	34 Surat Basin CCS Project (Previously Wandoan)
4 CIDA China	19 MRCSP Appalachian Basin (Burger) Phase II	35 SWP San Juan Basin Phase II
5 CS Energy Callide Oxyfuel Project	20 MRCSP Cincinnati Arch (East Bend) Phase II	36 Teapot Dome, Wyoming
6 CSEMP	21 MRCSP Michigan Basin Phase II	37 Lacq-Rousse
7 Fenn/Big Valley	22 Nagaoka Pilot CO2 Storage Project	38 West Pearl Queen
8 Frio, Texas	23 Otway I (Stage I)	39 WESTCARB Arizona Pilot (Cholla)
9 JCOP Yubari/Ishikari ECBM Project	24 Otway II Project (Stage 2A,B)	40 WESTCARB Northern California CO_2 Reduction Project
10 K12B	25 PCOR Lignite	41 WESTCARB Rosetta-Calpine test 1
11 Ketzin	26 PCOR Williston Basin -Phase II (NW McGregor Field)	42 WESTCARB Rosetta-Calpine test 2
12 Marshall County	27 PennWest Energy EOR Project	43 Western Kentucky
13 Masdar/ADCO Pilot project	28 Recopol	44 Zerogen Project
14 MGSC loudon Field EOR Phase II	29 SECARB - Black Warrior Basin Coal Seam Project	45 East Canton Oil Field
15 MGSC Mumford Hills EOR Phase II	30 SECARB - Central Appalachian Coal Seam Project	46 PCOR Zama Field Validation Project

Reference:
Gale and Wilson
2019, (Figure 1.2)

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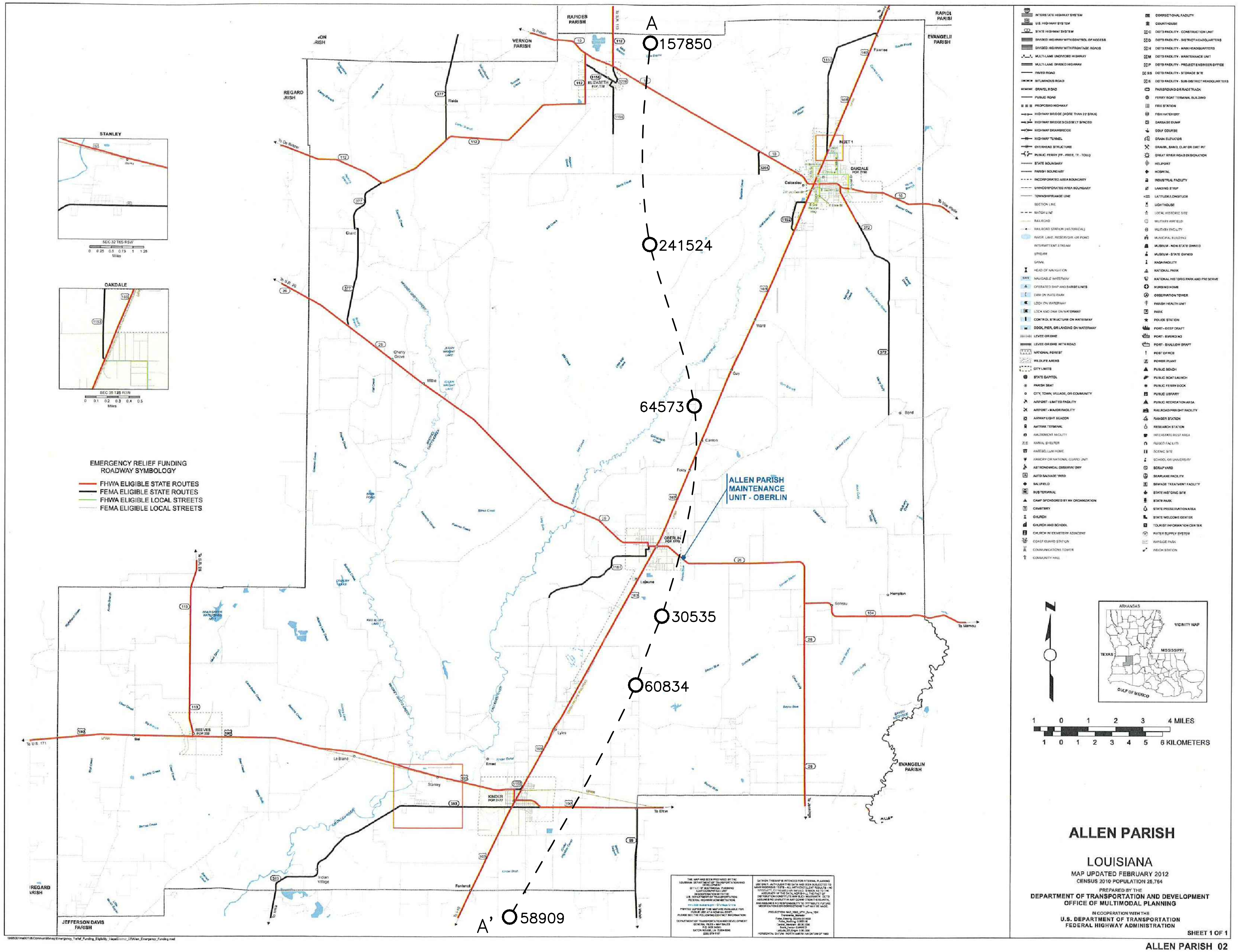
LOCATIONS OF CO2 SEQUESTRATION PROJECTS	FIGURE 1–6
	SCALE: N.T.S.
	DATE: JAN. 2025



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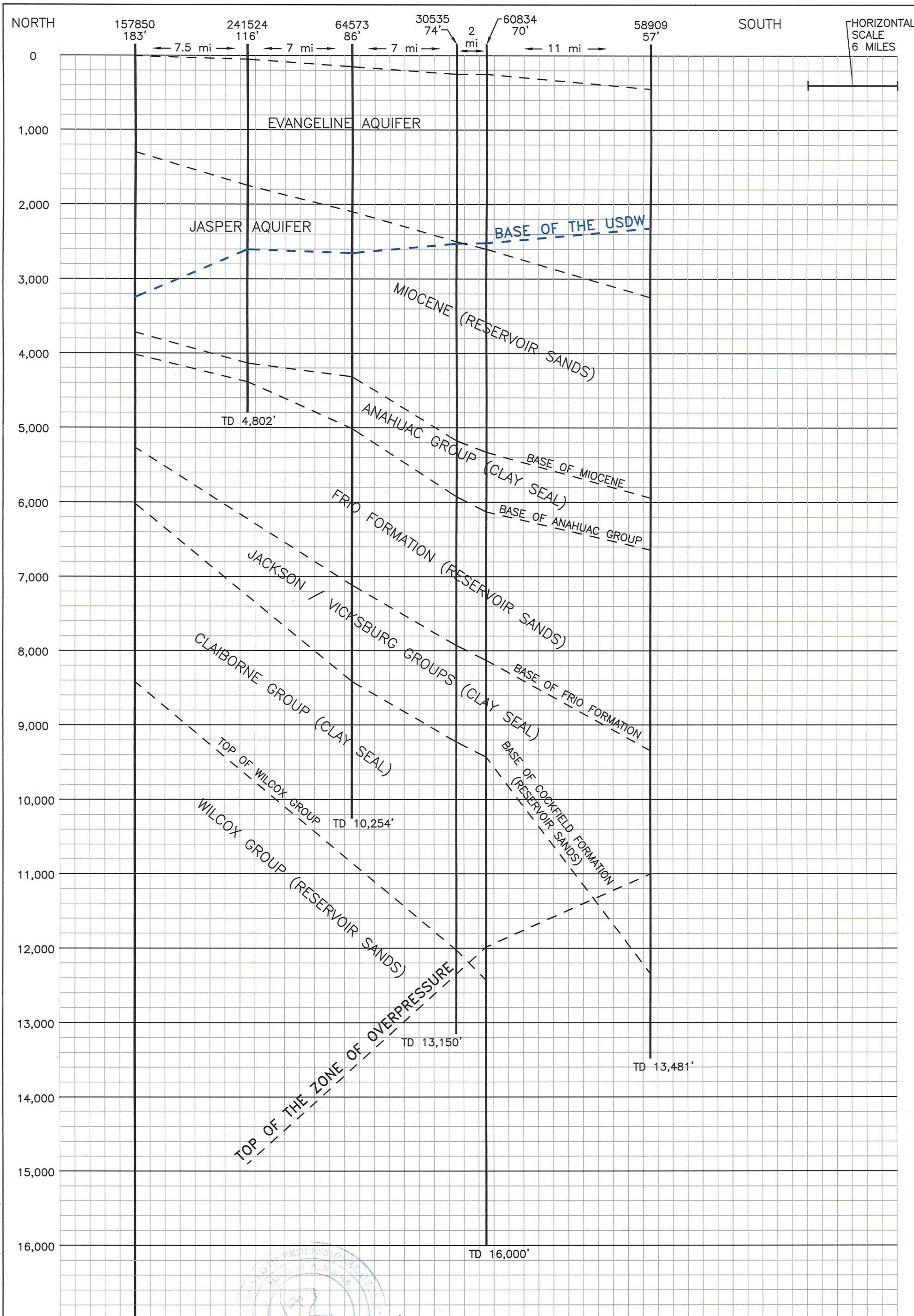
LOCATION OF GEOLOGIC CROSS SECTION A–A'	FIGURE 2–1
	SCALE: 1" = 8 MILE
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 2-1.dwg



Michael A. Simms
January 17, 2025

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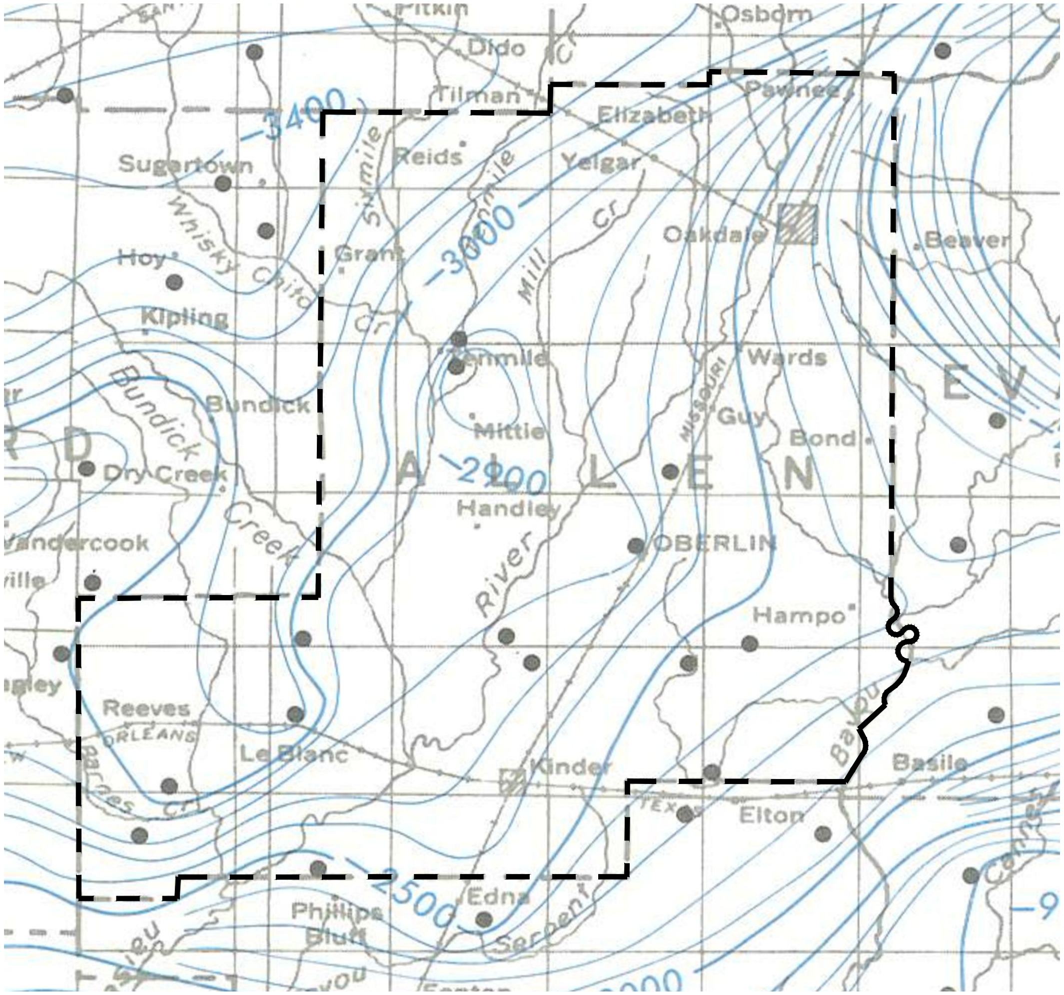
Prepared by: Michael A. Simms, PhD., P.G.
(Louisiana PG 1142)

NORTH – SOUTH GEOLOGIC CROSS SECTION A–A'	FIGURE 2–2
	SCALE: 1" = 6 MILE HORIZ.
	DATE: 11/8/2024

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 2-2.dwg



EXPLANATION

Control point

—100 Water-zone contour

Shows the approximate altitude of the 10,000 milligrams per liter dissolved-solids surface which defines the base of the moderately-saline-water zone and the top of the very-saline-water zone. Contour interval, in feet, is variable. Datum is mean sea level

Area where moderately-saline water is not present in aquifers

SCALE 1:750 000

10 0 10 20 30 40 MIL

Source:
Winslow, A.G., et al. (1968).
"Saline Ground Water in Louisiana."
Hydrologic Atlas 310.

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BASE OF USDW IN ALLEN PARISH	FIGURE 2–3
	SCALE: SEE DRAWING
	DATE: 11/8/2024

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 2-3.dwg

Incident outcomes				Likelihood of occurrence				
Severity rating	Health effects (people)	Property damage	Environment impact	1 Very Unlikely	2 Unlikely	3 Possible	4 Likely	5 Very Likely
5	Death or permanent total disability	Catastrophic damage	Significant impact	5	10	15	20	25
4	Permanent partial disability; hospitalizations of three people or more	Severe damage	Significant, but reversible impact	4	8	12	16	20
3	Injury or occupational illness resulting in one or more days away from work	Significant damage	Moderate reversible impact	3	6	9	12	15
2	Injury or occupational illness not resulting in a lost work day	Moderate damage	Minimal impact	2	4	6	8	10
1	First aid only or no injuries or illnesses	Light damage	No impact	1	2	3	4	5

Very high risk: **15 or greater** High risk: **10 –14** Moderate risk: **5 – 9** Low risk: **1 – 4**

Figure 1.3 Risk matrix example.

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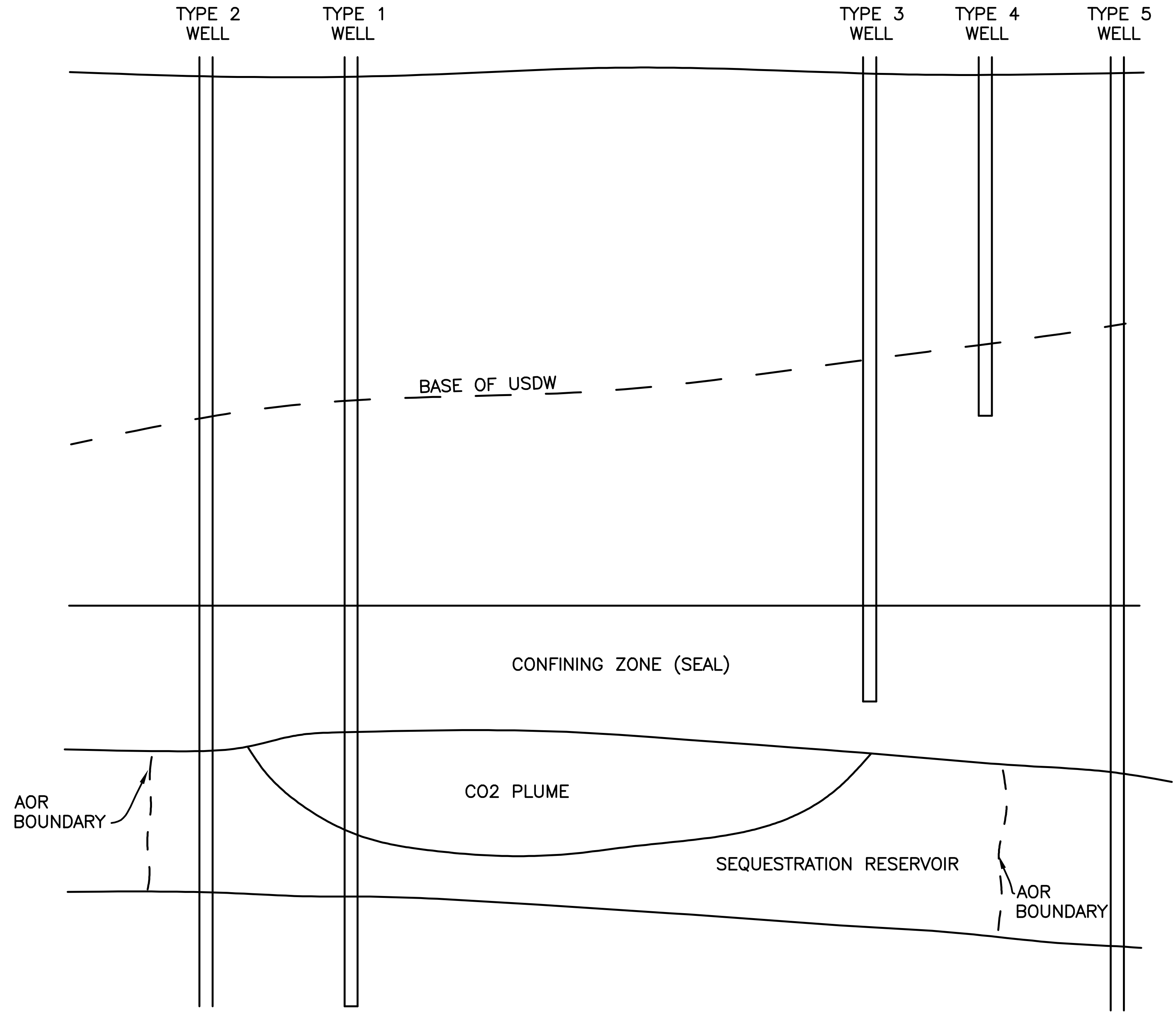
RISK MATRIX	FIGURE 4–1
	SCALE: N.T.S.
	DATE: JAN. 2025



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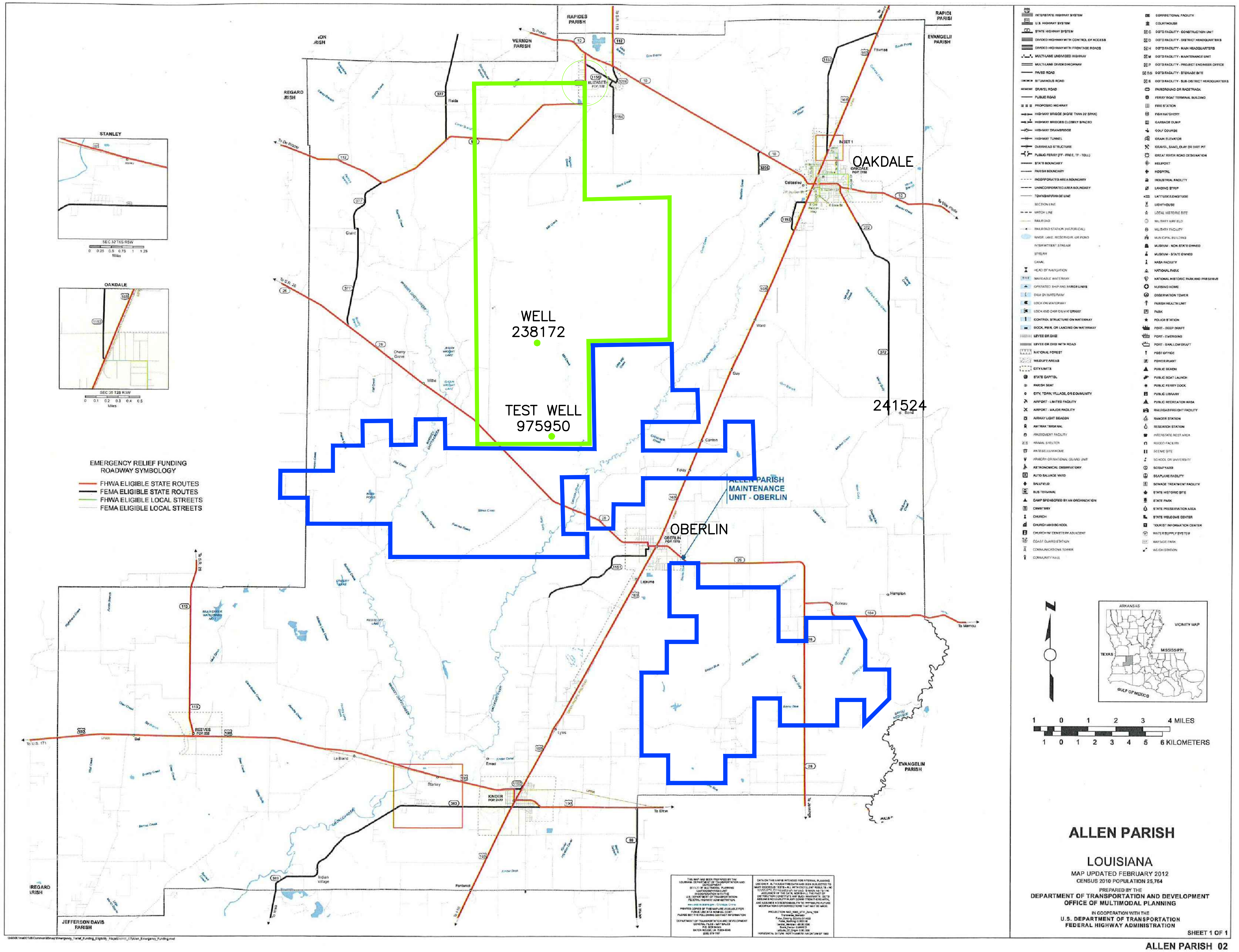
WELL RISK CATEGORIZATION	FIGURE 4–2
	SCALE: N.T.S.
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 4.dwg



LEGEND:

APPROXIMATE BOUNDARY
OXY LOW CARBON VENTURES, LLC.
SEQUESTRATION SERVITUDE

APPROXIMATE BOUNDARY
EXXON MOBIL LOW CARBON
SOLUTIONS ONSHORE STORAGE LLC.
CARBON DIOXIDE STORAGE
AGREEMENT AREAS

NOTE:
BOUNDARIES SHOWN FOR EXXON MOBIL PROJECTS ARE OUTER ENVELOPES OF LEASED SECTIONS.

BOUNDARIES ARE APPROXIMATE.

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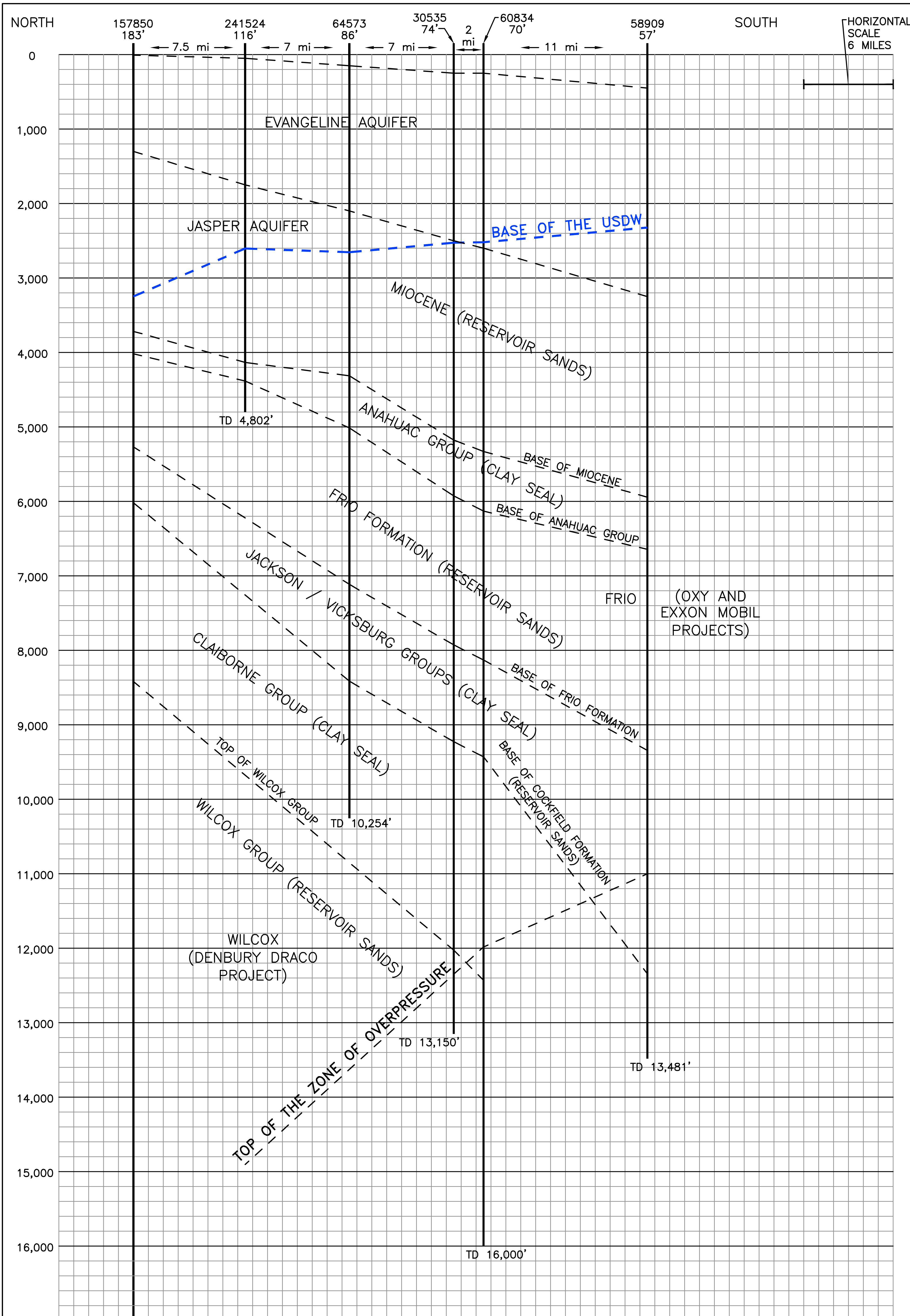
LOCATIONS OF CO2 SEQUESTRATION LEASES ALLEN PARISH	FIGURE 5–1
	SCALE: 1" = 4 MILE
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 5–1.dwg



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Prepared by: Michael A. Simms, PhD., P.G.
(Louisiana PG 1142)

ALLEN PARISH AREA
PROPOSED
SEQUESTRATION ZONES

FIGURE 5-2
SCALE: 1" = 6 MILE HORIZ.
DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 5-2.dwg

Reference:
National Petroleum Council
2019, (Figure 6–2)

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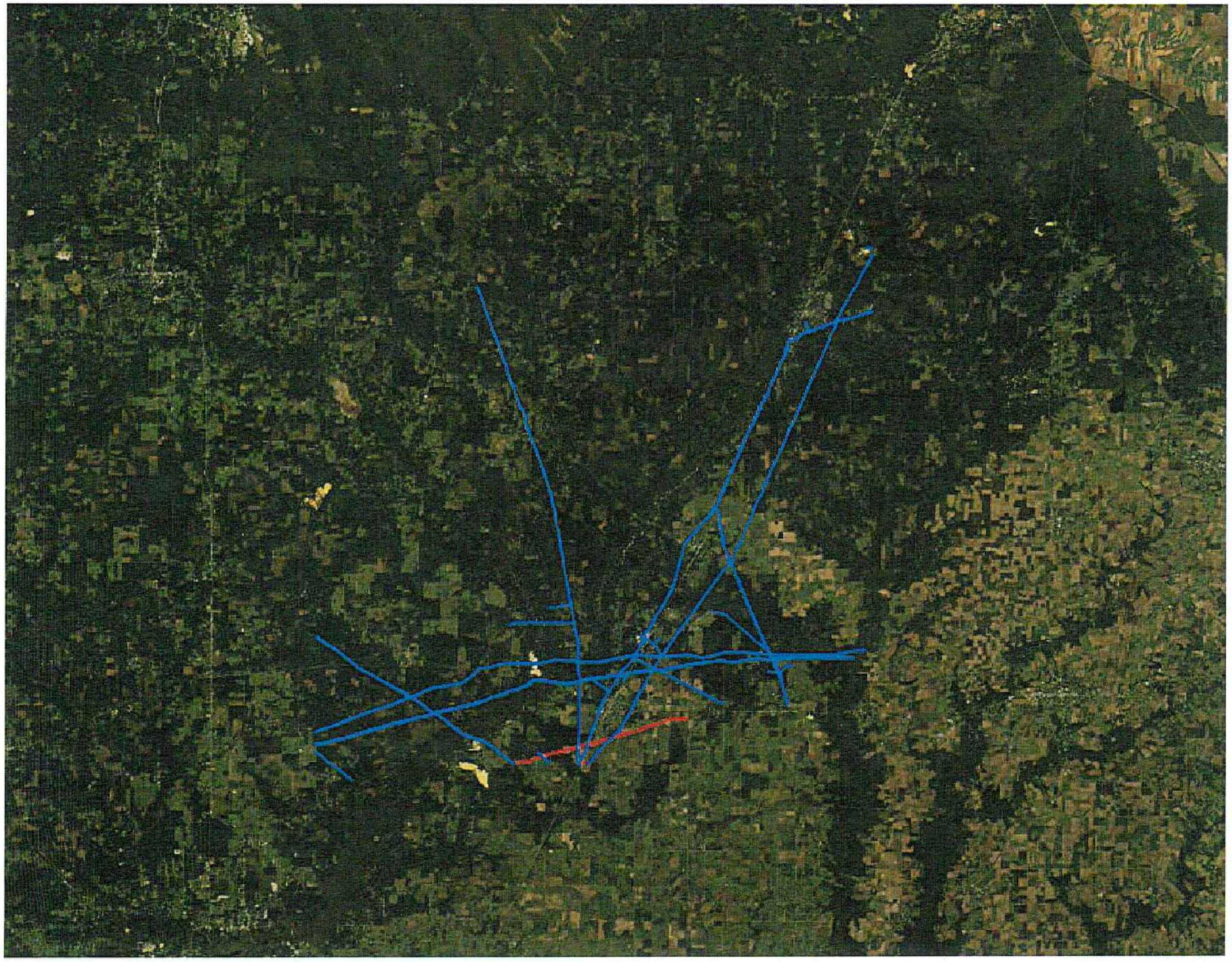
LOCATION OF CO2 PIPELINES IN THE US	FIGURE 5–3
	SCALE: N.T.S.
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 5-3.dwg

Pipeline and Hazardous Materials Safety Administration

NATIONAL PIPELINE MAPPING SYSTEM



Legend

- Gas Transmission Pipelines
- Hazardous Liquid Pipelines

10 km
5 mi

Pipelines depicted on this map represent gas transmission and hazardous liquid lines only. Gas gathering and gas distribution systems are not represented.

This map should never be used as a substitute for contacting a one-call center prior to excavation activities. Please call 811 before any digging occurs.

Questions regarding this map or its contents can be directed to npms@dot.gov.

Projection: Geographic

Datum: NAD83

Map produced by the Public Viewer application at www.npms.phmsa.dot.gov

World Imagery map service data is attributed to Esri, Maxar, Earthstar Geographics, and the GIS User Community.

Date Printed: Nov 12, 2024

811

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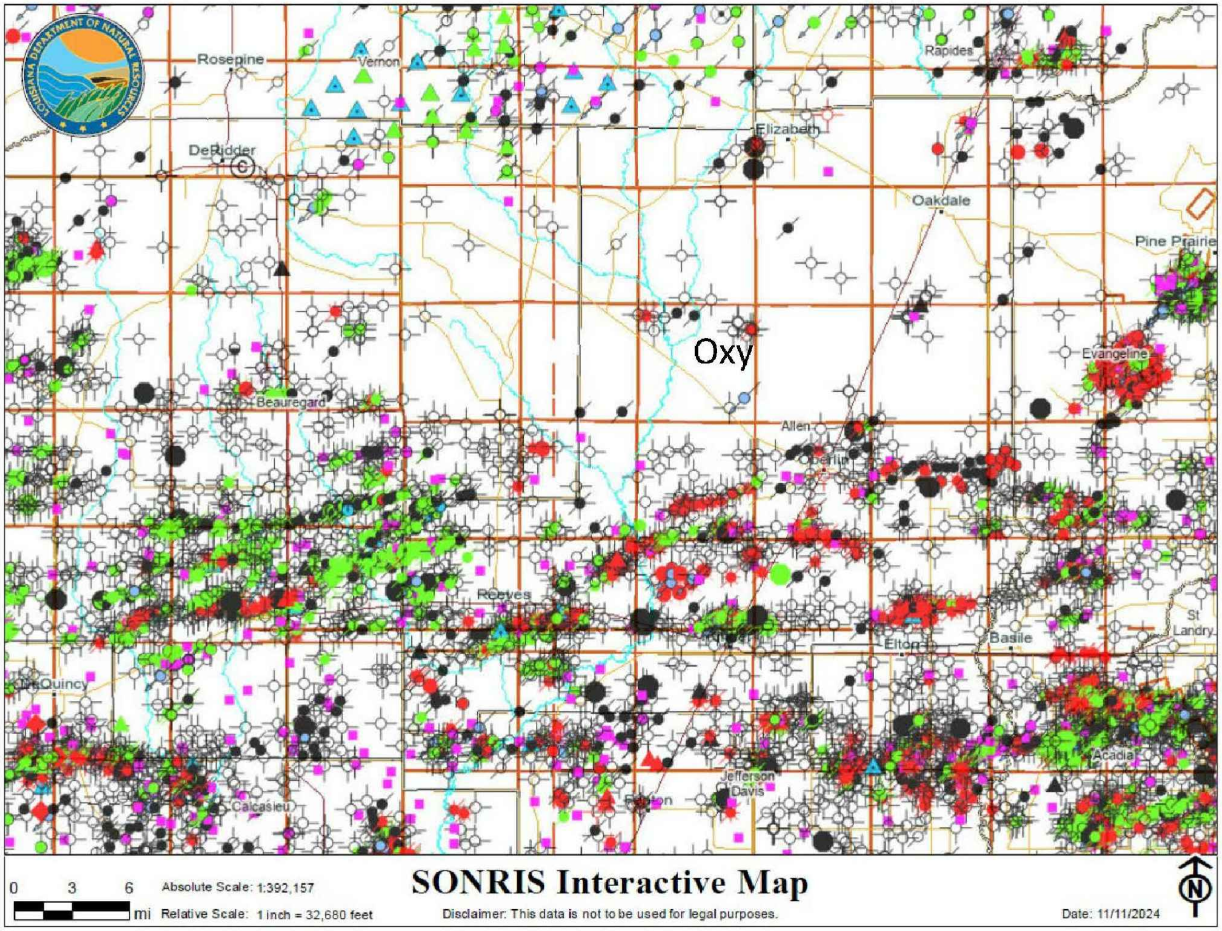
ALLEN PARISH PIPELINES	FIGURE 5-4
	SCALE: N.T.S.
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 5-4.dwg

Allen Parish Oil/Gas Wells



Reference:
Strategic Online Natural
Resources Information System

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ALLEN PARISH PETROLEUM WELLS	FIGURE 5–5
	SCALE: N.T.S.
	DATE: JAN. 2025

G:\Projects\2024 PROJECTS\ALLEN PARISH\DRAWINGS\ALLEN PARISH FIG 5-5.dwg

Appendix 1

CLASS VI WELL APPLICATIONS (1/6/2025)

Appendix 1

Louisiana Department of Energy and Natural Resources - Class VI Well Applications (1/6/2025)

Operator	Project Name	Parish	Number of Wells/Applications	Application Received by EPA	Declared Adminstratively Complete by EPA	Application Received by DENR	Declared Administratively Complete by DENR	Start of DENR Technical Review
Air Products Blue Energy, LLC	LCEC Carbon Sequestration Site South	St. John the Baptist	5	--	--	7/12/2024	7/17/2024	9/27/2024
BKVerde, LLC	Donaldsonville	Ascension	1	1/9/2024	1/25/2024	2/5/2024	7/25/2024	--
Capio Sequestration, LLC	Capio Sherburne CCS Well #1	Pointe Coupee	1	12/13/2022	2/16/2023	2/5/2024	4/30/2024	4/30/2024
Capio Maurepas Sequestration, LLC	Maurepas WMA Sequestration Project	St. John the Baptist	2	--	--	6/3/2024	7/10/2024	--
CapturePoint Solutions, LLC	CCS 1 - Wilcox	Rapides	6	6/24/2022	7/22/2022	2/5/2024	4/2/2024	4/2/2024
CapturePoint Solutions, LLC	CCS 2 - Wilcox 2	Vernon	6	3/14/2023	5/18/2023	2/5/2024	3/25/2024	3/25/2024
Cleco Power, LLC	Diamond Vault	Rapides	6	5/19/2023	8/9/2023	2/5/2024	3/7/2024	--
Denbury Carbon Solutions, LLC	Draco	Allen, Beauregard, and Vernon	6	7/6/2023	10/6/2023	2/5/2024	--	--
DT Midstream Holdings, LLC	LA CCS	Sabine	1	11/22/2022	3/27/2023	2/5/2024	6/5/2024	--
Evergreen Sequestration Hub, LLC	Evergreen Sequestration Hub	Beauregard	2	--	--	2/28/2024	3/19/2024	10/10/2024
ExxonMobil Low Carbon Solutions Onshore Storage LLC	Pecan Island Area Project	Vermillion	2	7/28/2023	9/6/2023	2/5/2024	--	--
Gulf Coast Sequestration	Minerva	Calcasieu	4	1/26/2022	3/10/2022	2/5/2024	8/14/2024	--
Gulf Coast Sequestration	Goose Lake	Calcasieu	2	8/31/2022	9/26/2022	2/5/2024	8/14/2024	--
Hackberry Carbon Sequestration, LLC	Hackberry Sequestration	Cameron	1	9/15/2021	11/9/2021	2/5/2024	3/15/2024	3/15/2024
Harvest Bend CCS LLC	White Castle	Iberville	3	10/25/2023	11/22/2023	2/5/2024	3/1/2024	--
Lapis Energy (LA Development), LP	Libra CO2 Storage Solutions Project	St. Charles	3	--	--	11/20/2024	12/2/2024	--
Live Oak CCS, LLC	Live Oak CCS Hub	West Baton Rouge	3	--	--	11/7/2024	11/26/2024	--
Live Oak CCS, LLC	Live Oak CCS Hub	Iberville	5	--	--	11/7/2024	11/26/2024	--
Louisiana Green Fuels LLC	LGF Columbia	Caldwell	3	3/15/2023	4/24/2023	2/5/2024	3/26/2024	3/26/2024
Magnolia Sequestration Hub, LLC	Magnolia	Allen	4	7/20/2021	3/10/2022	2/5/2024	4/23/2024	4/23/2024
OnStream CO2, LLC	GeoDura	Cameron	6	--	--	12/18/2024	1/6/2025	--
Pelican Sequestration Hub, LLC	Pelican Sequestration Project	Livingston	2	8/11/2023	2/2/2024	2/5/2024	4/23/2024	--
River Parish Sequestration, LLC	River Parish Sequestration - RPN 1	Ascension	1	5/10/2023	6/15/2023	2/5/2024	3/1/2024	5/28/2024
River Parish Sequestration, LLC	River Parish Sequestration - RPN 2	Assumption	1	5/25/2023	6/15/2023	2/5/2024	3/1/2024	--
River Parish Sequestration, LLC	River Parish Sequestration - RPN 3	Assumption	1	6/19/2023	6/22/2023	2/5/2024	3/1/2024	--
River Parish Sequestration, LLC	River Parish Sequestration - RPN 4	Iberville	1	7/9/2023	8/1/2023	2/5/2024	3/1/2024	--
River Parish Sequestration, LLC	River Parish Sequestration - RPN 5	Iberville	1	7/9/2023	8/1/2023	2/5/2024	3/1/2024	--
River Parish Sequestration, LLC	River Parish Sequestration - RPS 1 & 2	Assumption	2	8/31/2023	9/20/2023	2/5/2024	3/1/2024	--
Shell U.S. Power and Gas, LLC	El Camino	St. Helena	2	12/12/2022	3/9/2023	2/5/2024	4/3/2024	6/14/2024
Venture Global CCS Cameron, LLC	Venture Global CCS Cameron LLC CO2 Sequestration Project	Cameron	1	7/25/2023	--	2/5/2024	6/12/2024	6/12/2024

Appendix 2

ENVIRONMENTAL RISK EVALUATION

Appendix 2

Environmental Risk Evaluation

Federal Register, Vol. 75, No. 237, Friday, December 10, 2010, pgs 77237 - 77240

What steps did EPA take to develop this rulemaking?

1. Developing Guidance for Experimental GS Projects

In 2007, EPA issued technical guidance to assist State and EPA Regional UIC programs in processing permit applications for pilot and other small scale experimental GS projects. The guidance was developed in cooperation with DOE and States, the Ground Water Protection Council (GWPC), the Interstate Oil and Gas Compact Commission (IOGCC), and other stakeholders. *UIC Program Guidance #83: Using the Class V Experimental Technology Well Classification for Pilot Carbon GS Projects* (USEPA, 2007) provides recommendations for permit writers regarding the use of the UIC Class V experimental technology well classification at demonstration GS projects while ensuring USDW protection. Program guidance #83 is available at: *http://www.epa.gov/safewater/uic/wells_sequestration.html*. EPA is preparing additional guidance for owners or operators and Directors regarding the use of Class V experimental technology wells for GS following promulgation of today's rule.

2. Conducting Research

EPA participated in and supported research to inform today's rulemaking including: Supporting and tracking the development and results of national and international CO2 GS field and research projects; tracking GS-related State regulatory and legislative efforts; and conducting technical workshops on issues associated with CO2 GS. EPA described these research activities in detail in the proposed rule (July 2008) and the NODA and Request for Comment (August 2009). Additional information pertaining to these activities, which are summarized below, may be found in the rulemaking docket.

a. Tracking the Results of CO2 GS Research Projects

To inform today's rulemaking, EPA tracked the progress and results of national and international GS research projects. DOE leads field research on GS in the U.S. in conjunction with the Regional Carbon Sequestration Partnerships (RCSPs). Currently, DOE's NETL is developing and/or operating GS projects, a number of which have either completed injection or are in the process of injecting CO2. The seven RCSPs are conducting pilot and demonstration projects to study site characterization (including injection and confining formation information, core data and site selection information); well construction (well depth, construction materials, and proximity to USDWs); frequency and types of tests and monitoring conducted (on the well and on the project site); modeling and monitoring results; and injection operation (injection rates, pressures, and volumes, CO2 source and co-injectates). See section II.E.5 for more information on the status of these projects.

Lawrence Berkeley National Laboratory (LBNL) research: EPA and DOE are jointly funding work by the LBNL to study potential impacts of CO2 injection on ground water aquifers and drinking water sources. The preliminary results have been used to inform today's rulemaking and are described in detail in section II.E.5.

In addition, EPA is funding an analysis by LBNL to integrate experimental and modeling information. LBNL will characterize ground water samples and aquifer mineralogies from select sites in the U.S. and conduct controlled laboratory experiments to assess the potential mobilization of hazardous constituents by dissolved CO2. These experiments will provide data that will be used to validate previous predictive modeling studies (of aquifer vulnerabilities to potential CO2 leaks) which may be applied to other GS sites in the future to assess the fate and migration of CO2-mobilized constituents in ground water.

EPA's Office of Research and Development (ORD) GS research: EPA's ORD engages Agency scientists and engineers in targeted research to provide information to stakeholders and policy makers focused on areas of national environmental concern, including climate change and GS. In addition, ORD's National Center for Environmental Research (NCER) provides extramural research grants for similar investigations through a competitive solicitation process. In the fall of 2009, NCER awarded six Science To Achieve Results (STAR) grants to recipients from major universities and institutions. The awards were granted to projects focused on *Integrated Design, Modeling and Monitoring of GS of Anthropogenic CO4 to Safeguard Sources of Drinking Water.* Work under the grants began in late 2009 and includes: Evaluating potential impacts on drinking water aquifers of CO2-rich dissolved brines (Clemson University); reducing the hydrologic and geochemical uncertainties associated with CO2 sequestration in deep, saline reservoirs (University of Illinois-Urbana); assessing appropriate monitoring approaches at GS sites (University of Texas at Austin); integrating design, monitoring, and modeling of GS to assist in developing a practical methodology for characterizing risks to USDWs (University of Utah); conducting laboratory experiments on shallow aquifer systems to improve our understanding of geochemical and microbiological reactions under low pH/high CO2 stress (Columbia University); and, developing a set of computational tools to model CO2 and brine movement associated with GS (Princeton University).

International projects: EPA is tracking the progress of international GS efforts. The largest and longest-running commercial, large-scale projects in operation today include: The Sleipner Project in the Norwegian North Sea (operating since 1996); the Weyburn enhanced oil recovery (EOR) project in Saskatchewan, Canada (operating since 2000); the In Salah Gas Project in Algeria (operating since 2004); and Snohvit, also in offshore Norway in the Barents Sea (operating since 2008). Other projects EPA is tracking include Otway in Australia (operating since 2008); Ketzin in Germany (operating since 2008); and Lacq in France (operating since 2009). EPA is also tracking two projects that are anticipated to begin injection in the near future: CarbFix in Iceland (anticipated to commence injection in 2010) and Gorgon in Australia (anticipated to start in 2014). EPA evaluated available information and experiences gained from these international projects to inform today's action, as appropriate. Additional information on how these and other international projects informed the GS rulemaking is contained in the rulemaking docket (USEPA, 2010a).

b. Tracking State Regulatory Efforts

EPA has made it a priority to engage States and State organizations throughout the rulemaking effort. EPA recognizes the complexity and importance of the States' approaches to managing GS and is aware that States are in various stages of developing statutory frameworks, regulations, technical guidance, and strategies for addressing CCS and GS. Throughout the regulatory development process for the Class VI regulation, EPA monitored States' regulatory efforts and approaches and sought input on State activities related to addressing GS in the proposed rule and NODA. At present, several States have published GS regulations, while others are investigating and developing strategies to address GS issues (*e.g.,* management of multipurpose injection wells in oil and gas reservoirs). EPA is tracking regulatory efforts in 18 States: Colorado, Illinois, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia, and Wyoming. EPA is considering this information as it develops guidance on the primacy application and approval process for Class VI wells. Information about these State activities may be found in the docket for today's rulemaking.

c. Conducting Technical Workshops on Issues Associated With CO2 GS

EPA conducted a series of technical workshops with regulators, industry, utilities, and technical experts to identify and discuss questions relevant to the effective management of CO2 GS. The workshops included the following: Measurement, Monitoring, and Verification (in New Orleans, Louisiana on January 16, 2008); Geological Setting and AoR Considerations for CO2 GS (in Washington, DC on July 10–11, 2007); Well Construction and MIT (in Albuquerque, New Mexico on March 14, 2007); a State Regulators' Workshop on GS of CO_2 (in collaboration with DOE in San Antonio, Texas on January 24, 2007); an International Symposium on Site Characterization for CO_2 Geological Storage (co-sponsored with LBNL in Berkeley, California on March 20–22, 2006); Risk Assessment for Geologic CO_2 Storage (co-sponsored with the Ground Water Protection Council (GWPC) in Portland, Oregon on September 28–29, 2005); and Modeling and Reservoir Simulation for Geologic Carbon Storage (in Houston, Texas on April 6–7, 2005). Summaries of these workshops are available on EPA's Web site, at *http://www.epa.gov/safewater/uic/wells_sequestration.html*.

3. Conducting Stakeholder Coordination and Outreach

Throughout the rulemaking process, the Agency conducted public workshops and public hearings and consulted with specific groups. EPA representatives also attended meetings to explain the GS rulemaking effort to interested members of the public and stakeholder groups. Meeting information, notes, and summaries are available in the docket for this rulemaking.

Public stakeholder coordination: EPA held public meetings to discuss EPA's rulemaking approach, and consulted with other stakeholder groups including non-governmental organizations (NGOs) to gain an understanding of stakeholder interests and concerns. As part of this outreach, EPA conducted two public stakeholder workshops with participants from industry, environmental groups, utilities, academia, States, and the general public. These workshops were held in December 2007 and February 2008. Workshop summaries are available on EPA's Web site, at *http://www.epa.gov/safewater/uic/wells_sequestration.html*. EPA also coordinated with GWPC, a State association that focuses on ensuring safe application of injection well technology and protecting ground water resources, and IOGCC, a chartered State association representing oil and gas producing States throughout the rulemaking process. Members of GWPC and IOGCC have specific expertise regulating the injection of CO_2 for the ER of oil and gas. EPA staff attended national meetings and calls of these organizations, as well as those held by technical and trade organizations, NGOs, States, and Tribal organizations to discuss the rulemaking process and GS-specific technical issues.

Consultation with the National Drinking Water Advisory Council (NDWAC): In November 2008, during the public comment period for the proposed rule, EPA met with NDWAC to discuss the proposed rule. At the meeting, EPA presented information about the rulemaking and responded to NDWAC questions and comments. NDWAC members indicated that they understood the role of GS as a climate mitigation tool and encouraged the Agency to continue to ensure the protection of USDWs. Since proposal publication, EPA has met with NDWAC to discuss the status of the rule and answer questions from NDWAC members. The notes of these meetings are in the rulemaking docket.

Consultations with States, Tribes, and Territories: EPA engaged States, Tribes, and Territories early and throughout the rulemaking process to promote open communication and solicit input and feedback on all aspects of the rule.

In April of 2008, prior to publication of the proposed rule, the Agency sent background information about the rulemaking to all Federally-recognized Indian Tribes and invited participation in a dedicated GS consultation effort. EPA Regional Indian Coordinators (RICs), the National Indian Workgroup (NIWG), the National Tribal Caucus (NTC) and the National Tribal Water Council (NTWC) contacts were also invited to participate in the consultation. EPA provided additional rulemaking updates after publication of the proposal with the above-mentioned groups as well as the National Water Program State-Tribal Climate Change Council (STC3). The Fort Peck Assiniboine and Sioux Tribes and the Navajo Nation received UIC program primacy for the Class II program (under section 1425 of the SDWA) during the proposal period for this rule (73 FR 65556; 73 FR 63639). Therefore, the Agency initiated an additional consultation effort with these Tribal coregulators post-proposal. Summaries of the Tribal consultation conference calls are included in the docket for today's rulemaking.

To ensure that States were consulted, the Agency also sent background information about the rulemaking to States and State organizations including the National Governors' Association, National Conference of State Legislatures, Council of State Governments, and the National League of Cities, among others, and held a dedicated conference call on GS for interested State representatives in April 2008. Additionally, the Agency participated in rulemaking updates, as appropriate, during national meetings and conferences, and gave presentations to State organizations throughout development of the rule. A summary of these efforts is included in the docket for today's rulemaking.

Consultation with the United States Department of Health and Human Services (HHS): Pursuant to SDWA section 1421, EPA consulted with the U.S. Department of Health and Human Services during the rulemaking process. Prior to proposal publication and rule finalization, the Agency provided background information to HHS on the purpose and scope of the rule. In June of 2010, EPA met with HHS to discuss the GS rulemaking process as well as key elements of the proposed rule, the Notice of Data Availability and Request for Comment, and the final rule. During the June 2010 briefing, HHS participants asked about technical criteria for Class VI wells and monitoring technologies applicable to GS projects. The Agency addressed questions and comments and HHS certified that the EPA satisfied consultation obligations under the SDWA. The memo certifying this consultation is available in the docket for today's rulemaking.

4. Proposed Rulemaking

On July 25, 2008, EPA published the proposed Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells (73 FR 43492). The Agency proposed a new class of injection well (Class VI), along with technical criteria for permitting Class VI wells that tailored the existing UIC regulatory framework to address the unique nature of CO_2 injection for GS, including:

• Site characterization requirements that would apply to owners or operators of Class VI wells and require submission of extensive geologic, hydrogeologic, and geomechanical information on the proposed GS site to ensure that Class VI wells are located in suitable formations. EPA also proposed that owners or operators identify additional containment/confining zones, if required by the Director, to improve USDW protection.

• Enhanced AoR and corrective action requirements (e.g., plugging abandoned wells) to delineate the AoR for GS projects using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream. EPA also proposed that owners or operators periodically reevaluate the AoR around the injection well to incorporate monitoring and operational data and verify that the CO_2 is moving as predicted within the subsurface.

• Well construction using materials that are compatible with and can withstand contact with CO_2 over the life of the GS project.

• Multi-faceted monitoring of the CO_2 stream, injection pressures, the integrity of the injection well, groundwater quality above the confining zone(s), and the position of the CO_2 plume and the pressure front throughout injection.

• Comprehensive post-injection monitoring and site care until it can be demonstrated that movement of the plume and pressure front have ceased and the injectate does not pose a risk to USDWs.

• Financial responsibility requirements to ensure that financial resources would be available for corrective action, injection well plugging, post-injection site care, and site closure, and emergency and remedial response.

Following publication of the proposed rule, EPA initiated a 120-day public comment period, which the Agency extended by 30 days to accommodate requests from interested parties. The public comment period for the proposed rule closed on December 24, 2008.

EPA received approximately 400 unique submittals from 190 commenters, including late submissions. Commenters represented States; industry (including the oil and gas industry, electric utilities, and energy companies); environmental groups; and associations (including water organizations and CCS associations).

During the public comment period, the Agency held public hearings on the proposed rule in Chicago, IL on September 30, 2008 and in Denver, CO on October 2, 2008. The two hearings collectively drew approximately 100 people representing non-governmental organizations, academia, industry, and other organizations. At the hearings, 29 people submitted oral comments. Transcripts of the public hearings are in the rulemaking docket (Docket ID Nos. EPA–HQ–OW–2008–0390–0185 and EPA–HQ–OW–2008–0390–0256).

5. Notice of Data Availability and Request for Comment

Based on public comments received on the proposed rule, the Agency identified several topics on which it needed additional public comment. EPA published Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells; Notice of Data Availability and Request for Comment (74 FR 44802) on August 31, 2009, to describe additional topics and request comment.

The NODA and Request for Comment presented new data and information from three DOE-sponsored RCSP projects including: (1) The Escatawpa, Mississippi project; (2) the Aneth Field, Paradox Basin project in Southeast Utah; and, (3) the Pump Canyon Site project in New Mexico. Additional information on these projects and responses to comments received on the NODA and Request for Comment are available in the docket for this rulemaking.

The NODA and Request for Comment also provided results of two GS-related modeling studies conducted by the LBNL. The first study (Birkholzer *et al.*, 2008a) focused on the potential for GS to cause changes in ground water quality as a result of potential CO2 leakage and subsequent mobilization of trace elements such as arsenic, barium, cadmium, mercury, lead, antimony, selenium, zinc, and uranium. Results from this model simulation suggest that if CO2 were to leak into a shallow aquifer, mobilization of lead and arsenic could occur, causing increases in the concentration of these trace elements in ground water and potential for drinking water standard exceedances.

The second study modeled a theoretical scenario of GS in a sedimentary basin to demonstrate the potential for basin-scale hydrologic impacts of CO2 storage (Birkholzer *et al.*, 2008b). Model results indicate that basin-wide pressure influences may be large and that predicted pressure changes could move saline water upward into overlying aquifers if localized pathways, such as conductive faults, are present. This example illustrates the importance of basin-scale evaluation of reservoir pressures and far-field pressures resulting from CO2 injection.

Additional information on LBNL's research and responses to comments received on the NODA and Request for Comment are available in the docket for this rulemaking. The full publications on the LBNL research are also available on LBNL's Web site at http://esd.lbl.gov/GCS/projects/CO2/index_CO2.html.

Lastly, the NODA and Request for Comment presented an alternative to address public comments and concerns about the proposed injection depth requirements for Class VI wells. Section III.D of today's action contains more information on this subject.

Following publication of the NODA and Request for Comment, EPA initiated a 45-day public comment period, which closed on October 15, 2009. EPA received 67 unique submittals from 64 commenters, many of whom commented on the proposed rule. The Agency also held a public hearing in Chicago, IL on September 17, 2009. Six people, representing the oil and gas industry, electric utilities, water associations, and academia attended the hearing. Two attendees submitted oral comments at the hearing. A transcript of the public hearing is in the rulemaking docket (EPA–HQ–OW–2008–0390–391).

Appendix 3

FEDERAL REGISTER

Vol. 75, No. 237, Friday, December 10, 2010, pgs 77234 - 77235

Appendix 3

Federal Register, Vol. 75, No. 237, Friday, December 10, 2010, pgs 77234 - 77235

"What are the unique risks to USDWs associated with GS?"

"Large CO_2 injection volumes associated with GS, the buoyant and mobile nature of the injectate, the potential presence of impurities in the CO_2 stream, and its corrosivity in the presence of water could pose risks to USDWs. The purpose of today's Class VI requirements for GS is to ensure the protection of USDWs, recognizing that an improperly managed GS project has the potential to endanger USDWs. Proper siting, well construction, operation, and monitoring of GS projects are therefore necessary to reduce the risk of USDW contamination.

It is expected that GS projects will inject large volumes of CO_2. These volumes will be much larger than are typically injected in other well classes regulated through the UIC program, and could cause significant pressure increases in the subsurface. Supercritical or gaseous CO_2 in the subsurface is buoyant, and thus would tend to flow upwards if it were to come into contact with a migration pathway, such as a fault, fracture, or improperly constructed or plugged well. However, the pressures induced by injection will also influence CO_2 and mobilized fluids to flow away from the injection well in all directions, including laterally, upwards and downwards. When CO_2 mixes with formation fluids, a percentage of it will dissolve. The resulting aqueous mixture of CO_2 and water will sink due to a density differential between the mixture and the surrounding fluids. CO_2 is also highly mobile in the subsurface (i.e., has a very low viscosity), and, in the presence of water, CO_2 can be corrosive. These properties (of CO_2), as well as the large volumes that may be injected for GS result in several unique challenges for protection of USDWs in the vicinity of GS sites from endangerment.

While CO_2 itself is not a drinking water contaminant, CO_2 in the presence of water forms a weak acid, known as carbonic acid, that, in some instances, could cause leaching and mobilization of naturally-occurring metals or other contaminants from geologic formations into ground water (*e.g.,* arsenic, lead, and organic compounds). Another potential risk to USDWs is the presence of impurities in the captured CO_2 stream, which may include drinking water contaminants such as hydrogen sulfide or mercury. Additionally, pressures induced by injection may force native brines (naturally occurring salty water) into USDWs, causing degradation of water quality and affecting drinking water treatment processes. Research studies have shown that the potential migration of injected CO_2 or formation fluids into a USDW could cause impairment through one or several of these processes (e.g., Birkholzer *et al.,* 2008a)."

Appendix 4

FEDERAL REGISTER

Vol. 75, No. 237, Friday, December 10, 2010, pg. 77233

Appendix 4

Federal Register, Vol. 75, No. 237, Friday, December 10, 2010, pg. 77233

"Minimum technical criteria for Class VI wells to protect USDWs from endangerment"

- Site characterization that includes an assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that Class VI wells are located in suitable formations.
- Computational modeling of the AoR for GS projects that accounts for the physical and chemical properties of the injected CO2 and is based on available site characterization, monitoring, and operational data.
- Periodic reevaluation of the AoR to incorporate monitoring and operational data and verify that the CO2 plume and the associated area of elevated pressure are moving as predicted within the subsurface.
- Well construction using materials that can withstand contact with CO2 over the life of the GS project.
- Robust monitoring of the CO2 stream, injection pressures, integrity of the injection well, ground water quality and geochemistry, and monitoring of the CO2 plume and position of the pressure front throughout injection.
- Comprehensive post-injection monitoring and site care following cessation of injection to show the position of the CO2 plume and the associated area of elevated pressure to demonstrate that neither pose an endangerment to USDWs.
- Financial responsibility requirements to ensure that funds will be available for all corrective action, injection well plugging, post-injection site care (PISC), site closure, and emergency and remedial response.

Appendix 5

LDENR OC EPA REG COMPARISON TABLE

Appendix 5. A COMPARISON OF FEDERAL AND LOUISIANA REGULATIONS FOR CLASS VI INJECTION WELLS

The following is intended only as a general overview of notable differences between EPA and Louisiana rules for Class VI wells and does not include all administrative or procedural differences. This list should not be taken as comprehensive or be used in lieu of application instructions, Office of Conservation guidance, LAC 43:XVII.Chapter 36, or other relevant parts of state or federal law.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
N/A	N/A	§3603.H.2 and 3603.H.3	2. All applications, reports, plans, requests, maps, cross-sections, drawings, opinions, recommendations, calculations, evaluations, or other submittals including or comprising geoscientific work as defined by La. R.S. 37:711.1 et seq. must be prepared, sealed, signed, and dated by a licensed Professional Geoscientist (P.G.) authorized to practice by and in good standing with the Louisiana Board of Professional Geoscientists. 3. All applications, reports, plans, requests, specifications, details, calculations, drawings, opinions, recommendations, evaluations or other submittals including or comprising the practice of engineering as defined by La. R.S. 37:.681 et seq. must be prepared, sealed, signed, and dated by a licensed Professional Engineer (P.E.) authorized to practice by and in good standing with the Louisiana Professional Engineering and Land Surveying Board.	No federal equivalent.
40 CFR 144.5 (b) (See also 145.11(a)(1))	Claims of confidentiality for the following information will be denied: (1) The name and address of any permit applicant or permittee; (2) Information which deals with the existence, absence, or level of contaminants in drinking water.	§3603.I through 3603.I.2	1. the name and address of any permit applicant or permittee; and 2. information which deals with the existence, absence, or level of contaminants in drinking water or zones other than the approved injection zone.	This language is more restrictive than the federal equivalent as it refers to the presence of contaminants in any formation outside of the approved injection zone rather than just the USDW or in the drinking water.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 144.7(d)(2)(iv) (See also 145.11(a)(3))	Any information submitted to support a waiver request made by the owner or operator under § 146.95, if appropriate.	N/A	N/A	Waivers of the injection depth requirements for Class VI wells will not be granted.
40 CFR 144.22(b) (See also 145.11(a)(9))	Duration of well authorization by rule. Well authorization under this section expires upon the effective date of a permit issued pursuant to § 144.19, § 144.25, § 144.31, § 144.33 or § 144.34; after plugging and abandonment in accordance with an approved plugging and abandonment plan pursuant to §§ 144.28(c) and 146.10 of this chapter; and upon submission of a plugging and abandonment report pursuant to § 144.28(k); or upon conversion in compliance with § 144.28(j).	§3603.E.1.a	1. Class VI wells cannot be authorized by rule to inject carbon dioxide. Owners or operators of Class VI wells must obtain a permit. a. Any authorization by rule for an existing Class II enhanced recovery or hydrocarbon storage well shall expire upon the effective date of a Class VI permit issued pursuant to §3603.G, or well plug and abandonment according to an approved plug and abandonment plan, or upon well conversion.	Authorization by rule for Class VI wells will be prohibited.
40 CFR 144.33(a) (See also 145.11(a)(12))	The Director may issue a permit on an area basis, rather than for each well individually, provided that the permit is for injection wells:	§3605.B	B. The commissioner cannot issue a permit on an area basis for a Class VI well or permit.	Area permits will not be allowed for Class VI wells.
N/A	N/A	N/A	N/A	Emergency permits will not be granted for Class VI wells.
40 CFR 144.31(e)(6) (See also 145.11(a)(10))	A listing of all permits or construction approvals received or applied for under any of the following programs:	§3607.B.9	9. a listing of all permits or construction approvals that the applicant has received or applied for under any of the following programs or which specifically affect the legal or technical ability of the applicant to undertake the activity or activities to be conducted by the applicant under the permit being sought:	
40 CFR 144.31(e)(9) (See also 145.11(a)(10))	For EPA-administered programs, the applicant shall identify and submit on a list with the permit application the names and addresses of all owners of record of land within one-quarter mile of the facility boundary.	§3607.B.12	12. names and addresses of all property owners within the area of review of the Class VI well or project.	State rule specifies the area of review rather than property within one-quarter mile of the facility boundary.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 144.32(a)(1) through 144.32(a)(1)(ii)	For a corporation: by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means;	§3605.E.1 through 3605.E.4	1. Corporations … c. the written authorization is submitted to the Office of Conservation.	Provides different definitions of responsible corporate officers or duly authorized representative. See state rule for full details.
N/A	N/A	§3611.I.3	3. Approval or the granting of a permit to construct a Class VI well shall be valid for a period of one year and if not begun in that time, the permit shall be null and void. The permittee may request an extension of this one-year requirement; however, the commissioner shall approve the request for extenuating circumstances only.	
40 CFR 144.38(a) (See also 145.11(a)(16))	Transfers by modification. Except as provided in paragraph (b) of this section, a permit may be transferred by the permittee to a new owner or operator only if the permit has been modified or revoked and reissued (under § 144.39(b)(2)), or a minor modification made (under § 144.41(d)), to identify the new permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act.	§3613.C.2 through 3613.C.2	2. Causes for modification or revocation and reissuance. The following are causes to modify or, alternatively, revoke and reissue a permit: a. cause exists for termination under §3613.E, and the commissioner determines that modification or revocation and reissuance is appropriate; or b. the commissioner has received notification of a proposed transfer of the permit and the transfer is determined not to be a minor modification (see §3613.D.4). A permit may be modified to reflect a transfer after the effective date (§3613.F.2.b) but will not be revoked and reissued after the effective date except upon the request of the new permittee; or. c. a determination that the waste being injected is a hazardous waste as defined in §3601 either because the definition has been revised, or because a previous determination has been changed; or d. to incorporate such other requirements as may be necessary under the Safe Drinking Water Act	

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 144.38(b) (See also 145.11(a)(16))	Automatic transfers. As an alternative to transfers under paragraph (a) of this section, any UIC permit for a well not injecting hazardous waste or injecting carbon dioxide for geologic sequestration may be automatically transferred to a new permittee if:	N/A	N/A	Automatic transfer of permits for Class VI wells will be prohibited.
40 CFR 144.39 (See also 145.11(a)(17))	When the Director receives any information (for example, inspects the facility, receives information submitted by the permittee as required in the permit (see § 144.51 of this chapter), receives a request for modification or revocation and reissuance under § 124.5, or conducts a review of the permit file) he or she may determine whether or not one or more of the causes listed in paragraphs (a) and (b) of this section for modification or revocation and reissuance or both exist. If cause exists, the Director may modify or revoke and reissue the permit accordingly, subject to the limitations of paragraph (c) of this section, and may request an updated application if necessary. When a permit is modified, only the conditions subject to modification are reopened. If a permit is revoked and reissued, the entire permit is reopened and subject to revision and the permit is reissued for a new term. See § 124.5(c)(2) of this chapter. If cause does not exist under this section or § 144.41 of this chapter, the Director shall not modify or revoke and reissue the permit. If a permit modification satisfies the criteria in § 144.41 for ''minor modifications'' the permit may be modified without a draft permit or public review. Otherwise, a draft permit must be prepared and other procedures in part 124 must be followed.	§3613.B through 3613.B.5	B. Permit Actions 1. The permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition. ... 5. If the commissioner decides to modify or revoke and reissue a permit under §§3613.C, D, and E, he shall prepare a draft permit under §3611.C incorporating the proposed changes. When a permit is modified, the entire permit is reopened and is subject to revision. The commissioner may request additional information and, in the case of a modified permit, may require the submission of an updated permit application. In the case of revoked and reissued permits, the commissioner shall require, if necessary, the submission of a new application.	See state rule for full detail regarding procedural differences but note that the entire permit may be reopened and modified whenever a permit is modified.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 144.39(a)(2) (See also 145.11(a)(17))	Information. The Director has received information. Permits other than for Class II and III wells may be modified during their terms for this cause only if the information was not available at the time of permit issuance (other than revised regulations, guidance, or test methods) and would have justified the application of different permit conditions at the time of issuance. For UIC area permits (§ 144.33), this cause shall include any information indicating that cumulative effects on the environment are unacceptable.	§3613.C.1.b	b. Information. The commissioner has received information pertinent to the permit that would have justified the application of different permit conditions at the time of issuance.	State rule does not account for whether or not the information was available at the time of permit issuance.
40 CFR 144.51(d) (See also 145.11(a)(19))	Duty to mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.	§609.G	G. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment such as the contamination of underground sources of drinking water resulting from noncompliance with this permit.	Added language: "such as the contamination of underground sources of drinking water resulting…"
40 CFR 144.51(l)(1) (See also 145.11(a)(19))	Reporting requirements. (1) Planned changes. The permittee shall give notice to the Director as soon as possible of any planned physical alterations or additions to the permitted facility.	§3609.L.1	1. Planned Changes. The permittee shall give notice to the commissioner as soon as possible of any planned physical alterations or additions to the permitted facility	State rule requires reporting of any changes, regardless of whether they may require a modification.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 144.51(q)(1) (See also 145.11(a)(19))	Duty to establish and maintain mechanical integrity. The owner or operator of a Class I, II, III or VI well permitted under this part shall establish mechanical integrity prior to commencing injection or on a schedule determined by the Director. Thereafter the owner or operator of Class I, II, and III wells must maintain mechanical integrity as defined in §146.8 of this chapter and the owner or operator of Class VI wells must maintain mechanical integrity as defined in §146.89 of this chapter.	§3609.P	P. Duty to Establish and Maintain Mechanical Integrity. The permittee of a Class VI injection well shall establish mechanical integrity prior to commencing injection and on a schedule determined by these rules or the commissioner. Thereafter, Class VI injection wells must maintain mechanical integrity as defined in §3627. The Class VI injection well owner or operator shall give notice to the commissioner when it is determined the injection well is lacking mechanical integrity. Upon receiving such notice, the operator shall immediately cease injection into the well. The well shall remain out of injection service until such time as well mechanical integrity is restored to the satisfaction of the commissioner. The owner or operator may resume injection upon written notification from the commissioner that the owner or operator has demonstrated mechanical integrity pursuant to §3627.	The state rule includes more stringent requirements the operator shall immediately cease injection into the well upon receipt of written notice from the commissioner. The well shall remain out of injection service until such time as well mechanical integrity is restored to the satisfaction of the commissioner. While the potential courses of action in the federal language are not explicitly enumerated in §3609.P, the commissioner has authority to require whatever remedial actions are deemed necessary until mechanical integrity is restored to the satisfaction of the commissioner.
40 CFR 144.51(l)(5) (See also 145.11(a)(19))	Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than 30 days following each schedule date.	§3609.L.5	5. Compliance Schedules. Report of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule in these regulations shall be submitted to the commissioner no later than 14 days following each schedule date.	State rules includes more stringent requirements compared to the federal rule, specifically implementing at 14 day period in lieu of the 30 day period in 40 CFR 144.51(l)(5).

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 144.51(q)(2) (See also 145.11(a)(19))	When the Director determines that a Class I, II, III or VI well lacks mechanical integrity pursuant to §§146.8 or 146.89 of this chapter for Class VI of this chapter, he/she shall give written notice of his/her determination to the owner or operator. Unless the Director requires immediate cessation, the owner or operator shall cease injection into the well within 48 hours of receipt of the Director's determination. The Director may allow plugging of the well pursuant to the requirements of §146.10 of this chapter or require the permittee to perform such additional construction, operation, monitoring, reporting and corrective action as is necessary to prevent the movement of fluid into or between USDWs caused by the lack of mechanical integrity. The owner or operator may resume injection upon written notification from the Director that the owner or operator has demonstrated mechanical integrity pursuant to §146.8 of this chapter.	§3609.P	See above.	See above.
40 CFR 146.81(b)	This subpart applies to any wells used to inject carbon dioxide specifically for the purpose of geologic sequestration, i.e., the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations.	§3603.A.2	2. The provisions of this Chapter only apply to geologic sequestration of carbon dioxide in underground reservoirs as defined in §3601 above. The geologic sequestration of carbon dioxide is not permitted in solution-mined salt caverns under these provisions.	Added language: "the geologic sequestration of carbon dioxide is not permitted in solution-mined salt caverns under these provisions."

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 146.82(a)(2)	A map showing the injection well for which a permit is sought and the applicable area of review consistent with 40 CFR 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	§3607.C.1.a.i through 3607.C.1.v	1. Maps and Related Information a. map(s) showing property boundaries of the facility, the location of the proposed Class VI well, and the applicable area of review consistent with §§3615.B and 3615.C . USGS topographic maps with a scale of 1:24,000 may be used. The map boundaries must extend at least two miles beyond the area of review and include as applicable: ... v. the protocol followed to identify, locate, and ascertain the condition of all wells within the area of review that penetrate the injection or confining zone.	See state rule for full detail of additional specific map requirements.
40 CFR 146.82(a)(3)(vi)	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	§3607.C.1.b.i through 3607.C.1.b.ii	i. geologic and topographic maps and cross-sections illustrating regional geology, geologic structure, and hydrology. ii. maps and cross-sections to a scale needed to detail the local geology, geologic structure, and hydrology. The maps and cross-sections must extend at least two miles beyond the area of review	More detailed requirement for geolgic mapping.
40 CFR 146.82(a)(4)	A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	§3607.C.2.d	d. a tabulation of all wells within the area of review that penetrate the base of the USDW. Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any other information the commissioner may require;	Added requirement that all wells penetrating the base of the USDW be included in the tabulation.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 146.84(b)(2)(iv)	How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	§3615.B.2.b.iv	iv. how corrective action will be conducted to meet the requirements of §3615.C, including what corrective action will be performed prior to injection and what, if any, portions of the area of review the operator proposes to have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	A phased approach to corrective action will be considered on a case-by-case basis.
40 CFR 146.85(a)(1)(iv)	Insurance	N/A	N/A	Insurance, self insurance, and escrow accounts will not be accepted as a form of financial surety for the activities detailed at §3609.C.1 and 3609.C.2. This is separate from the §3609.C.4.iv requirement that the owner/operator must maintain insurance to respond to any emergency or to perform any remedial action.
40 CFR 146.85(a)(1)(v)	Self Insurance (i.e., Financial Test and Corporate Guarantee)	N/A	N/A	
40 CFR 146.85(a)(1)(vi)	Escrow Account	N/A	N/A	
40 CFR 146.85(a)(2)(iv)	Emergency and remedial response (that meets the requirements of 40 CFR 146.94).	§3609.C.4.a.iv	iv. emergency and remedial response of §3623. The owner/operator shall maintain third party insurance at a sufficient level to respond to any emergency or to perform any remedial action that meets the requirements of §3623.	Clarification that insurance for emergency/remedial response must be third party insurance.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 146.85(a)(6)(i)	In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.	§3609.C.4.e.i	i. In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance, for example certificates of deposit, surety bonds, and letters of credit guaranteeing payment to the Louisiana Office of Conservation upon failure of the Operator to meet permit conditions or obligations under this Chapter. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.	As stated above, self insurance, escrow accounts, and insurance will not be allowed as financial instruments. Also, the state language requires that instruments of financial responsibility be issued in sole favor of the Office of Conservation, thereby averting the need to establish a standby trust for third party instruments.
40 CFR 146.85(a)(6)(ii)	When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	§3609.C.3	3. Any financial instrument filed in satisfaction of the financial responsibility requirements shall be issued by and drawn on a bank or other financial institution authorized under state or federal law to operate in the State of Louisiana.	Clarifies demonstration of proof of financial responsiblities for third-party providers.
40 CFR 146.85(a)(6)(iii)	An owner or operator using certain types of third party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.	N/A	N/A	As stated above, §3609.C.4.e.i requires that instruments of financial responsibility be issued in sole favor of the Office of Conservation, thereby averting the need to establish a standby trust for third party instruments.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 146.85(a)(6)(iv)	An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.	N/A	N/A	As stated above, escrow will not be an accepted form of financial assurance for the activities detailed at §3609.C.1 and 3609.C.2. However, the owner/operator may establish a site specific trust account as detailed at §609.C.1.d to be held in the Carbon Dioxide Geologic Storage Trust Fund as detailed at La. R.S. 30:1110.A.1 through 1110.B.6.
40 CFR 146.86(a)	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	§3617.A.1	1. General. All phases of Class VI well construction shall be supervised by a person knowledgeable and experienced in practical drilling engineering and is familiar with the special conditions and requirements of injection well construction. All materials and equipment used in the construction of the well and related appurtenances shall be designed and manufactured to exceed the operating requirements of the specific project, including flow induced vibrations. The owner or operator must ensure that all wells are constructed and completed to:	State rule requirements includes requirements regarding work experience for the construction supervisor and design requirements for construction materials.
40 CFR 146.86(b)(2)	Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	§3617.A.2.b	b. The surface casing of any Class VI well must extend into a confining bed—such as a shale—below the base of the deepest formation containing a USDW. The casing shall be cemented with a sufficient volume of cement to circulate cement from the casing shoe to the surface. The commissioner will not grant an exception or variance to the surface casing setting depth.	State rule includes text requiring the surface casing shoe be set below the USDW into a confining bed and states that variances to surface casing depth will not be granted.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 146.86(b)(4)	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	§3617.A.2.d through 3617.A.2.d.ii	d. Circulation of cement may be accomplished by staging. ... ii. Remedial cementing shall be done before proceeding with further well construction, completion, or conversion if adequate cement isolation of the USDW or the injection zone within the casing-formation annulus cannot be demonstrated.	See state rule for full detail of additional specific cement requirements
40 CFR 146.86(b)(4)	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	§3617.A.2.d through 3617.A.2.d.ii	d. Circulation of cement may be accomplished by staging. ... ii. Remedial cementing shall be done before proceeding with further well construction, completion, or conversion if adequate cement isolation of the USDW or the injection zone within the casing-formation annulus cannot be demonstrated.	See state rule for full detail of additional specific requirements for cement.
N/A	N/A	§3617.A.3 through 3617.A.3.b.i	3. Casing and Casing Seat Tests. … i. Casing seat test pressures shall never exceed the known or calculated fracture gradient of the appropriate subsurface formation.	See state rule for full detail of additional specific requirements for casing and casing seat tests.
40 CFR 146.87(a)(2)(i)	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	§3617.B.1.b.i	i. resistivity, gamma-ray, spontaneous potential, and caliper logs before the casing is installed; and	State rule requires that gamma-ray logs be run prior to casing installation.
40 CFR 146.87(a)(3)	Before and upon installation of the long string casing:	§3617.B.1.c	c. before and upon installation intermediate and long string casing:	State rule requires logs detailed in the following subsections be conducted also be conducted before and upon installation of the intermediate casing.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 146.87(f)	The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	§3617.B.6	6. The owner or operator must notify the Office of Conservation at least 72 hours before conducting any wireline logs, well tests, or reservoir tests.	State rule requires 72 hour notice rather than 30 days.
40 CFR 146.88(c)	The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	§3621.A.3 through 3621.A.4	3. The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the commissioner or a fluid containing a corrosion inhibitor approved by the commissioner. 4. Annulus Pressure. The owner or operator shall maintain a tubing-casing annulus pressure that exceeds the operating injection pressure, unless the commissioner determines that such requirement might harm the integrity of the well or endanger a USDW. A request to operate the well at a reduced annulus pressure must be in writing and approved by the commissioner.	State rule includes additional requirements regarding operating a well at reduced annulus pressure.
40 CFR 146.88(e)(1)	Continuous recording devices to monitor: the injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	§3621.A.6 through 3621.6.b	6. Continuous recording devices shall be installed, used, and maintained in proper working order for each well. a. continuous recording devices shall monitor: i. surface injection or bottom-hole pressure; ii. flow rate, volume and/or mass, and temperature of the carbon dioxide stream; iii. tubing-casing annulus pressure and annulus fluid volume; iv. any other data specified by the commissioner. b. continuous recordings shall consist of digital recordings. Instruments shall be weatherproof or housed in weatherproof enclosures when located in areas exposed to climatic conditions.	State rules allows for the monitoring of surface injection or bottom-hole pressure. It also requires that continuous records consist of digital recording and includes specific requirements.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
N/A	N/A	§621.A.7.a.iii	iii. all alarms must be integrated with any automatic shutdown system.	Specifies additional state regulations regarding alarms: all alarms must be integrated with any automatic shutdown system.
N/A	N/A	§3621.A.7.c	c. All emergency shutdown systems shall be fail-safe. The operator shall function-test all critical systems of control and safety at least once every six months. This includes testing of alarms, test tripping of emergency shutdown valves ensuring their closure times are within design specifications, and ensuring the integrity of all electrical, pneumatic, and hydraulic circuits. Test dates and results shall be documented and be available for inspection by an agent of the Office of Conservation.	Specifies additional state regulations regarding testing for components of emergency shutdown systems.
N/A	N/A	§3621.A.8 through 621.A.8.b	8. Wellhead Identification and Protection a. A protective barrier shall be installed and maintained around the wellheads, piping, and above ground structures that may be vulnerable to physical or accidental damage by mobile equipment or trespassers. b. An identifying sign shall be placed at the wellhead of each injection well and shall include at a minimum the operator's name, well name and number, well serial number, section-township-range, and any other information required by the commissioner. The sign shall be of durable construction with all lettering kept in a legible condition.	

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
N/A	N/A	§3621.A.9	9. Well Workovers. No well remedial work, well maintenance or repair, well or injection formation stimulation, well plug and abandonment or temporary abandonment, any other test of the injection well conducted by the permittee, or well work of any kind, shall be done without prior written authorization from the commissioner. The operator shall submit a work permit request form (Form UIC-17 or successor) to seek well work authorization.	
N/A	N/A	§3621.A.10	10. Pressure gauges that show pressure on the injection tubing and tubing-casing annulus shall be installed at each wellhead. Gauges shall be designed to read in increments of 10 PSIG. All gauges shall be properly calibrated and be maintained in good working order. The pressure valves onto which the pressure gauges are affixed shall have one-half inch female fittings.	
40 CFR 146.89(b)	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in 40 CFR 146.88 (e);	§3627.A.2 through 3627.A.2.b	2. To evaluate the absence of significant leaks, owners or operators must: a. perform an annulus pressure test: i. after initial well construction or conversion as part of the pre-operating requirements; ii. at least once every 12 months witnessed by an agent of the Office of Conservation; and iii. after performing any well remedial work that involves unseating the tubing or packer. b. continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in §3621.A.6.	State rule details actions that would trigger an annulus performance test.
N/A	N/A	§3629.A.1.h	h. the raw operating data from the continuous recording devices prescribed by §3621.A.6 submitted in digital format.	Requires the submission of raw operating data from continuous monitoring devices with each semi-annual report.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 146.91(d)	Owners or operators must notify the Director in writing 30 days in advance of:	§3629.A.4	4. Owners or operators must notify the commissioner in writing in advance of doing any well work or formation testing as required in §3621.A.9.	State rule does not require 30 day notice.
N/A	N/A	§3629.B	B. Recordkeeping. Owners or operators of Class VI wells shall retain records as specified in §§3615.C.4, 3629.A.6, 3631.A.5, 3633.A.6, and 3633.A.8.	Requires the retention of records related to AOR modeling inputs and data used to support area of review reevaluations; data and reports enumerated in the previous subsection (§3629.A.6); well closure; site closure; and any records gathered during the post-injection site care period for at least 10 years following site closure.
40 CFR 146.92(b)	Well Plugging Plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	§3631.A.3	3. Well Plugging Plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan acceptable to the commissioner. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application, must be designed in a way that will prevent the movement of fluids into or between USDWs or outside the injection zone, and must include the following minimum information:	Adds the require that design must prevent the movement of fluids into or between USDWs or outside the injection zone.

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
40 CFR 146.92(c)	Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to 40 CFR 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.	§3631.A.4	4. Notice of Intent to Plug. The owner or operator must submit the Form UIC-17, or successor form, to the commissioner and receive written approval from the commissioner before beginning actual well plugging operations. The form must contain information on the procedures to be used in the field to plug and abandon the well.	State rule does not require 60 day notice.
40 CFR 146.92(d)	Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to 40 CFR 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	§3631.A.5	5. Well Closure Report. The owner or operator shall submit a closure report to the commissioner within 30 days after well plug and abandonment. The report shall be certified as accurate by the owner or operator and by the person charged with overseeing the closure operation (if other than the owner or operator). The owner or operator shall retain the well closure report at least 10 years following site closure. The report shall contain the following information:	Added state requirement that a closure report must be submitted wihin 30 days after P&A.
N/A	N/A	§3633.B	B. Certificate of Completion . The commissioner shall not issue a certificate of completion pursuant to R.S. 1109 unless the operator has sufficient financial surety with the Office of Conservation to adequately close the facility, plug all existing wells, and provide for post-injection site care and site closure.	

Federal Citation	CFR Text	LA Citation	LA Rule Text	Difference
N/A	N/A	N/A	The owner or operator will be required to conduct an environmental justice review of communities located within the project AOR. The results of this review will be used to determine if an enhanced public comment period will be required for the application. An enhanced public comment period may extend the public comment period for the application, may require a more inclusive public participation process, including targeted public outreach and creation of better visual tools and approachable language, or may be supplemented in other ways recommended by the reviewer. In addition to the site location questions considered in the Environmental Justice review, a weighing of siting, environmental effects, and a cost benefit analysis is required in the application as a result of Save Ourselves, Inc., et al vs. the Louisiana Environmental Control Commission, et al1. The five required question responses, colloquially known as the “Louisiana Constitutional Considerations,” the “IT Question Responses,” or the “Save Ourselves Questions,” are hereafter the “SOS Decision Questions”, and are presented in Appendix II. Answers to these questions must provide adequate detail with sufficient justification and supporting data to enable LOC to conduct a balanced review of environmental, social, economic and other factors as required by the Louisiana Constitution.	No federal equivalent.

Appendix 6

WELL CONSTRUCTION AND COMPLETION

§3617. Well Construction and Completion

A. Injection Well Construction Requirements

1. General. All phases of Class VI well construction shall be supervised by a person knowledgeable and experienced in practical drilling engineering and is familiar with the special conditions and requirements of injection well construction. All materials and equipment used in the construction of the well and related appurtenances shall be designed and manufactured to exceed the operating requirements of the specific project, including flow induced vibrations. The owner or operator must ensure that all wells are constructed and completed to:

a. prevent the movement of fluids into or between USDWs or into any unauthorized zones;

b. allow the use of appropriate testing devices and workover tools; and

c. allow for continuous monitoring of the annulus space between the injection tubing and long string casing.

2. Casing and Cementing of Class VI Wells

a. Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids that the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the commissioner. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the commissioner to evaluate casing and cementing requirements, the owner or operator must provide the following information:

i. depth to the injection zone(s);

ii. injection pressure, external pressure, internal pressure, and axial loading;

iii. hole size;

iv. size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);

v. corrosiveness of the carbon dioxide stream and formation fluids;

vi. down-hole temperatures;

vii. lithology of injection and confining zone(s);

viii. type or grade of cement and cement additives including slurry weight (lb/gal) and yield (cu. ft./sack); and

ix. quantity, chemical composition, and temperature of the carbon dioxide stream.

b. The surface casing of any Class VI well must extend into a confining bed—such as a shale—below the base of the deepest formation containing a USDW. The casing shall be cemented with a sufficient volume of cement to circulate cement from the casing shoe to the surface. The commissioner will not grant an exception or variance to the surface casing setting depth.

c. At least one long string casing, using a sufficient number of centralizers, shall be utilized in the well. If the casing is to be perforated for injection, then the approved casing shall extend through the base of the injection zone. If an approved alternate construction method is used, such as the setting of a screen, the casing shall be set to the top of the injection interval. Regardless of the construction method utilized, the casings shall be cemented by circulating cement from the casing shoe to the surface in one or more stages.

d. Circulation of cement may be accomplished by staging. Circulated to the surface shall mean that actual cement returns to the surface were observed during the primary cementing operation. A copy of the cementing company's job summary or cementing tickets indicating returns to the surface shall be submitted as part of the pre-operating requirements.

i. The commissioner may approve an alternative method of cementing in cases where the cement cannot be circulated to the surface. If cement returns are lost during cementing, the owner or operator shall have the burden of showing—using wireline logs—that sufficient cement isolation is present to prevent the movement of fluid behind the well casing.

ii. Remedial cementing shall be done before proceeding with further well construction, completion, or conversion if adequate cement isolation of the USDW or the injection zone within the casing-formation annulus cannot be demonstrated.

e. Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.

3. Casing and Casing Seat Tests. The owner or operator shall monitor and record the tests using a surface readout pressure gauge and a chart or a digital recorder. All instruments shall be calibrated properly and in good working order. If there is a failure of the required tests, the owner or operator shall take necessary corrective action to obtain a passing test.

a. Casing. After cementing each casing, but before drilling out the respective casing shoe, all casings shall be hydrostatically pressure tested to verify casing integrity and the absence of leaks. For surface casing, the stabilized test pressure applied at the surface shall be a minimum of 500 pounds per square inch gauge (PSIG). The stabilized test pressure applied at the surface for all other casings shall be a minimum of 1,000 PSIG. All casing test pressures shall be maintained for one hour after stabilization. Allowable pressure loss is limited to five percent of the test pressure over the stabilized test duration.

i. Casing test pressures shall never exceed the rated burst or collapse pressures of the respective casings.

b. Casing Seat. The casing seat and cement of any intermediate and injection casings shall be hydrostatically pressure tested after drilling out the casing shoe. At least 10 feet of formation below the respective casing shoes shall be drilled before the test. The test pressure applied at the surface shall be a minimum of 1,000 PSIG. The test pressure shall be maintained for one hour after pressure stabilization. Allowable pressure loss is limited to five percent of the test pressure over the stabilized test duration.

i. Casing seat test pressures shall never exceed the known or calculated fracture gradient of the appropriate subsurface formation.

4. Tubing and Packer

a. Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids that the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the commissioner.

b. Injection into a Class VI well must be through tubing with a packer set at a depth opposite an interval of cemented casing at a location approved by the commissioner.

c. In order for the commissioner to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:

i. depth of setting;

ii. characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;

iii. maximum proposed injection pressure;

iv. maximum proposed annular pressure;

v. proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;

vi. size of tubing and casing; and

vii. tubing tensile, burst, and collapse strengths.

B. Logging, Sampling, and Testing Prior to Injection Well Operation

1. During the drilling and construction of a Class VI well, appropriate logs, surveys and tests must be run to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements of §3617 and to establish accurate baseline data against which future measurements may be compared. The well operator must submit to the commissioner a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:

a. deviation checks during drilling of all boreholes constructed by drilling a pilot hole, which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling;

b. before and upon installation of the surface casing:

i. resistivity, gamma-ray, spontaneous potential, and caliper logs before the casing is installed; and

ii. a cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.

c. before and upon installation of intermediate and long string casing:

i. resistivity, gamma-ray, spontaneous potential, porosity, caliper, fracture finder logs, and any other logs the commissioner requires for the given geology before the casing is installed; and

ii. a cement bond and variable density log, and a temperature log after the casing is set and cemented.

d. a series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:

i. a pressure test with liquid or gas;

ii. a tracer-type survey to detect fluid movement behind casing such as a radioactive tracer or oxygen-activation logging, or similar tool;

iii. a temperature or noise log;

iv. a casing inspection log.

e. any alternative methods that provide equivalent or better information and that are required by and approved by the commissioner.

2. The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the commissioner a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information. The commissioner may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The commissioner may require the owner or operator to core other formations in the borehole.

3. The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).

4. At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):

a. fracture pressure;

b. other physical and chemical characteristics of the injection and confining zone(s); and

c. physical and chemical characteristics of the formation fluids in the injection zone(s).

5. Upon completion, but before operating, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):

a. a pressure fall-off test; and,

b. a pump test; or

c. injectivity tests.

6. The owner or operator must notify the Office of Conservation at least 72 hours before conducting any wireline logs, well tests, or reservoir tests.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq., 30:22 et seq., and 30:1101 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 47:70 (January 2021).

Appendix 7
TESTING AND MONITORING

§3625. Testing and Monitoring

A. Testing and Monitoring Requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be included with the permit application and must include a description of how the owner or operator will meet these requirements—including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must include, at a minimum:

1. analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;

2. installation and use of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the tubing-casing annulus; and the annulus fluid volume added. Continuous monitoring is not required during well workovers as defined in §3621.A.5;

3. 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 to ensure that the well components meet the minimum standards for material strength and performance set forth in §3617.A.2, by:

a. analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or

b. routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or

c. using an alternative method approved by the commissioner;

4. periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:

a. the location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and

b. the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under §3607.C.2.e and on any modeling results in the area of review evaluation required by §3615.B.3.

5. a demonstration of external mechanical integrity pursuant to §3627.A.3 at least once every 12 months until the injection well is permanently plugged and abandoned; and, if required by the commissioner, a casing inspection log pursuant to requirements at §3627.A.4 at a frequency established in the testing and monitoring plan;

6. a pressure fall-off test at least once every five years unless more frequent testing is required by the commissioner based on site-specific information;

7. testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:

a. direct methods in the injection zone(s); and

b. indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the commissioner determines that such methods are not appropriate, based on site-specific geology;

8. The commissioner may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.

a. Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;

b. The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under §3603.D;

c. If an owner or operator demonstrates that monitoring employed under 40 CFR 98.440 to 98.449 accomplishes the goals of §3625.A.8.a. and b., and meets the requirements pursuant to §3629.A.1.c.v, a regulatory agency that requires surface air/soil gas monitoring must approve the use of monitoring employed under 40 CFR 98.440 to 98.449. Compliance with 40 CFR 98.440 to 98.449 pursuant to this provision is considered a condition of the Class VI permit;

9. Any additional monitoring, as required by the commissioner, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under §3615.B.3 and to determine compliance with standards under §3619;

10. The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under §3625, operational data collected under §3621, and the most recent area of review reevaluation performed under §3615.C.2. In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the commissioner that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the commissioner, must be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate. Amended plans or demonstrations shall be submitted to the commissioner as follows:

a. within 12 months of an area of review reevaluation;

b. following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the commissioner; or

c. when required by the commissioner.

11. a quality assurance and surveillance plan for all testing and monitoring requirements.

B. Monitoring and Records

1. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

2. The permittee shall retain records of all monitoring information, including the following:

a. calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of the sample, measurement, report, or application. This period may be extended by request of the commissioner at any time; and

b. the nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures specified under §3629 The commissioner may require the owner or operator to deliver the records to the commissioner at the conclusion of the retention period.

3. Records of monitoring information shall include:

a. the date, exact place, and time of sampling or measurements;

b. the individual(s) who performed the sampling or measurements;

c. the date(s) analyses were performed;

d. the individual(s) who performed the analyses;

e. the analytical techniques or methods used; and

f. the results of such analyses.

4. Owners or operators of Class VI wells shall retain records as specified in §§3615.C.4, 3629.A.4, 3631.A.5, 3633.A.6, and 3633.A.8 of this chapter.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4 et seq., 30:22 et seq., and 30:1101 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 47:74 (January 2021).

Appendix 8
PLUGGING AND ABANDONMENT

§3631. Plugging and Abandonment

A. Well Plugging and Abandonment.

1. A Class VI permit shall include conditions that meet the requirements set forth in this subsection and shall be incorporated into the permit as a permit condition. For purposes of this subsection, temporary or intermittent cessation of injection operations is not abandonment.

2. Before well plugging, the owner or operator must flush each Class VI well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.

3. Well Plugging Plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan acceptable to the commissioner. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application, must be designed in a way that will prevent the movement of fluids into or between USDWs or outside the injection zone, and must include the following minimum information:

a. appropriate tests or measures for determining bottomhole reservoir pressure;

b. appropriate testing methods to ensure external mechanical integrity as specified in §3627;

c. a description of the size and amount of casing, tubing, or any other well construction materials to be removed from the well before well closure;

d. that prior to the placement of plugs, the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method;

e. the type and number of plugs to be used;

f. the placement of each plug, including the elevation of the top and bottom of each plug;

g. the type, grade, yield, and quantity of material, such as cement, to be used in plugging. The material must be compatible with the carbon dioxide stream;

h. the method of placement of the plugs;

i. pre-closure and proposed post-closure well schematics;

j. that each plug shall be appropriately tagged and tested for seal and stability;

k. that the well casings shall be cut at least five feet below ground surface for land-based wells, and at least 15 feet below the mud line for wells at a water location.

l. that upon successful completion of well closure of a land-based well, a one-half (½) inch steel plate shall be welded across all casings and inscribed with the well's state serial number and date plugged and abandoned, and

m. any addition information that the commissioner may require.

Appendix 9
CLOSURE AND POST-CLOSURE

§3633. Closure and Post-Closure

A. Post-Injection Site Care and Site Closure.

1. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of §3633.A.1.b and is acceptable to the commissioner. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.

a. The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application.

b. The post-injection site care and site closure plan must include the following information:

i. the pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);

ii. the predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under §3615.B.3.a;

iii. a description of post-injection monitoring location, methods, and proposed frequency;

iv. a proposed schedule for submitting post-injection site care monitoring results to the commissioner and to the USEPA pursuant to §3629.A.3; and,

v. the duration of the post-injection site care timeframe and, if approved by the commissioner, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.

c. Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the commissioner through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the commissioner, be incorporated into the permit, and are subject to the permit modification requirements at §3613, as appropriate.

d. At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the commissioner's approval within 30 days of such change.

2. The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.

a. Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the commissioner-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the commissioner pursuant to requirements in §3633.A.3, unless the owner or operator makes a demonstration under §3633.A.2.b. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under §3633.A.2.b is submitted and approved by the commissioner.

b. If the owner or operator can demonstrate to the satisfaction of the commissioner before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the commissioner may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where the owner or operator has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.

c. Prior to authorization for site closure, the owner or operator must submit to the commissioner for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.

d. If the demonstration in §3633.A.2.c cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the commissioner does not approve the demonstration, the owner or operator must submit to the commissioner a plan to continue post-injection site care until a demonstration can be made and approved by the commissioner.