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Classification and Calibration of Legacy Well Risks for CO2 Storage In the Gulf Coast Basin

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Classification and Calibration of Legacy Well Risks for CO_2 Storage

In the Gulf Coast Basin

by

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Dedication

I dedicate this thesis to my family, my extended family, and my friends whose love, support, and encouragement have carried me trough every stage of this journey

I also express my sincere gratitude to The University of Texas at Austin, the Bureau of Economic Geology, and the Gulf Coast Carbon Center for providing the academic and research environment that made this work possible.

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Abstract

Classification and Calibration of Legacy Well Risks for CO_2 Storage In the Gulf Coast Basin

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The Gulf Coast Basin is one of the most important regions for large-scale geological carbon dioxide (CO_2) storage in the United States. More than 50 proposed carbon capture and storage (CCS) projects are concentrated in the basin, which is characterized by thick clastic sedimentary successions and favorable reservoir-seal architecture. At the same time, the basin contains more than one million legacy oil and gas wells. Many of these wells were drilled prior to modern well construction and abandonment standards and may represent potential leakage pathways if they are hydraulically connected to storage reservoirs or exposed to injection-driven pressure. This study examines how legacy well leakage risk is defined, screened, and classified in existing CCS risk assessment frameworks and evaluates the extent to which those frameworks are supported by empirical evidence. The analysis integrates evidence from multiple sources, including published legacy well risk classification methodologies, S&P Global well records, the Texas Railroad Commission (RRC) well failure database, and operational experience from Class I disposal wells. The Orange Borehole Closure Test is also used as a field-based analogue to evaluate whether open boreholes through shale can become hydraulically isolated under injectionrelated conditions and to assess how similar testing concepts could be adapted to Gulf Coast Class VI CO_2 storage settings. Results from the RRC dataset indicate that classified incidents are dominated by operational events rather than confirmed long-term leakage pathways relevant to geologic CO_2 storage. Of 521 classified incidents, 257 (49.3%) are associated with small-operations or failure-

while-drilling events, 79 (15.2%) with corrosion or aging materials, and 60 (11.5%) with hydrocarbon leaks, whereas only 19 incidents (3.6%) are classified as geological integrity breach. Evidence from Class I injection practice likewise shows that penetrations near injection intervals are evaluated primarily based on hydraulic relevance, pathway potential, and pressure communication, rather than by intrinsic well attributes alone. Overall, the study supports a more evidence-informed and pathway-based approach to legacy well risk classification for CCS projects in the Gulf Coast Basin. By integrating geological context, empirical failure evidence, field-tested concepts, and a proposed testing framework the study provides a more defensible basis for screening legacy wells and improving the consistency and practical relevance of risk classification for large-scale CO_2 storage deployment.

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CHAPTER I: INTRODUCTION

1.1. INTRODUCTION

Climate Change and the Role of Carbon Capture and Storage

Climate change is one of the major environmental challenges facing modern society and is driven largely by the accumulation of greenhouse gases in the atmosphere through human activities, especially fossil fuel combustion and industrial activity (IPCC, 2023). Because modern economies remain heavily dependent on carbon-intensive energy systems, reducing emissions requires a portfolio of mitigation approaches rather than a single solution (IEA, 2022; Metz et al., 2005).

Carbon capture and storage (CCS) is one of the key technologies in that mitigation portfolio. CCS involves capturing CO_2 from major emission sources, transporting the captured CO_2, and injecting it into deep geological formations for long-term storage to prevent its release into the atmosphere (IPCC, 2005; Metz et al., 2005). It is particularly relevant in sectors such as cement, steel, hydrogen, and fossil fuel-based power generation, where emissions are difficult to eliminate through electrification or renewable energy alone (IEA, 2022).

Research Background

Geological CO_2 storage is widely considered a promising approach for reducing atmospheric CO_2 emissions by permanently storing in deep subsurface formations. In this approach, CO_2 captured from industrial or energy facilities is transported to suitable geological formations and injected into porous rock formations located deep underground. These formations typically include deep saline aquifers, depleted oil and gas reservoirs, and unmineable coal seams within sedimentary basins, which provide both the storage capacity and geological conditions necessary to contain large volumes of CO_2 (Benson and Cole, 2008; Bachu, 2008). Suitable storage reservoirs must have sufficient porosity and permeability to allow injection and storage of CO_2, while overlying sealing formations such as shale or mudstone act as caprocks that prevent upward migration of the injected fluids (Benson and Cole, 2008).

The long-term effectiveness of geologic CO_2 storage depends on the integrity of the subsurface confinement system. After injection, CO_2 is retained through several trapping mechanisms whose relative importance changes over time. Structural and stratigraphic trapping are typically most important during the early stage of storage, whereas capillary (residual) trapping, dissolution into formation brines, and mineral trapping contribute increasingly to longer-term retention (Benson et al., 2008b).

Because injected CO_2 is typically less dense than formation water, buoyancy tends to drive it upward, while injection-induced pressure can drive fluid movement outward from the injection interval. Accordingly, storage security depends on the effectiveness of the overall confinement system rather than on a single impermeable layer. In practice, this means the confining units, stratigraphic architecture, and any penetrations such as wells must collectively prevent upward migration of CO_2 and pressure-driven displacement of formation fluids into overlying units, underground sources of drinking water (USDW), or the atmosphere (Benson et al., 2008b; Office of Water (4605M), 2013c).

Despite the presence of mechanisms that favor long-term retention, the potential for leakage remains one of the main public and permitting concerns associated with geological CO_2 storage. Identification and assessment of the possibility for permeable pathways that could allow CO_2 or displaced formation fluids to migrate from the storage reservoir into overlying geological formations, or to the surface is needed to provide assurance that leakage can be avoided. Potential leakage pathways may include existing wells, other penetrations, or transmissive features.(Office of Water (4605M), 2013c; Celia et al., 2010c).

Anthropogenic structures created during historical oil and gas exploration and production can also create potential leakage risks. Many sedimentary basins that are suitable for CO_2 storage have experienced extensive hydrocarbon development, resulting in large numbers of existing wells that penetrate multiple geological layers. These wells are designed to act as conduits to connect deep storage formations with the surface. At the same time, wells are engineered to control fluid flow and isolate subsurface zones through barriers such as casing, cement, tubing, packers, valves, and plugs (Porse et al., 2014b). Leakage through wells can occur when these barriers fail or do not provide complete isolation. Potential mechanisms include poorly bonded cement at the casing-formation or casing-cement interface, flow through degraded cement, corrosion of casing, tubing or packer failure, annular leakage, damaged or degraded cement plugs, and incomplete isolation during abandonment (IPCC, 2005; Nordbotten et al., 2005b; IEA GREENHOUSE GAS R&D PROGRAMME, 2012b).

Improperly designed or managed legacy exploration or oil and gas wells are therefore widely recognized as one of the most important potential leakage pathways in CCS systems. In North America, millions of oil and gas wells have been drilled during more than a century of exploration and production activities, and the Gulf Coast Basin alone contains approximately 1.1 million wells associated with hydrocarbon production, gas storage, and waste disposal activities (IHS Markit Inc., 2020; US EPA, 2020; Fryklund and Stark, 2020). Legacy wells should not be treated as equally risky simply because they were drilled at different times under different historical practices; rather, they should be evaluated based on construction, barrier placement, plugging condition, and hydraulic relevance to the storage system. If CO_2 injection occurs in regions with a high density of legacy wells, CO_2 plumes and the Area of Review (AoR) may intersect multiple existing wells, so those wells must be evaluated before injection to determine whether pre-existing weaknesses could permit fluid migration under storage conditions. Under the U.S. Class VI Underground Injection Control (UIC) framework, operators are required to delineate the AoR, identify wells and other penetrations within it, and demonstrate protection of USDW by predicting, monitoring, and controlling the lateral and vertical movement of injected CO_2 and displaced formation fluids (Office of Water (4605M), 2013c; US EPA, n.d.-b).

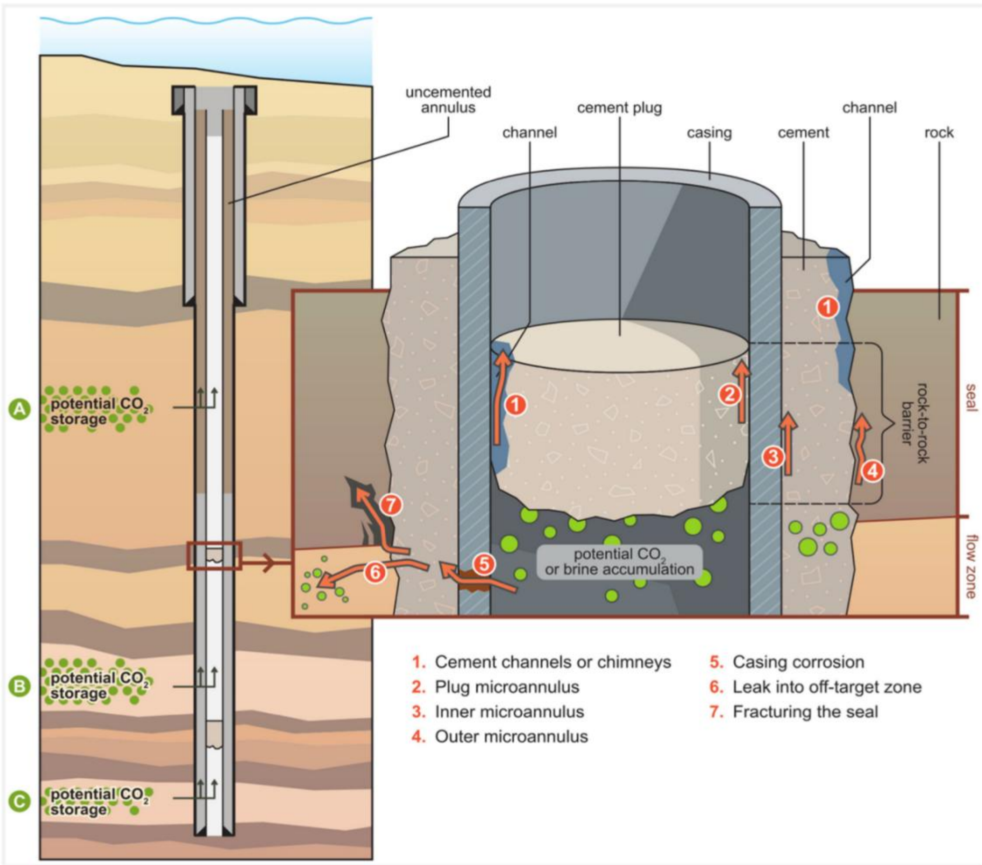

Figure 1. The main well-related migration pathways relevant to legacy-well integrity, including annular pathways, cement defects, casing corrosion, plug microannuli, and fracture-related leakage (adapted from Lackey et al. 2026).

Figure 1. illustrates that legacy-well leakage risk is not limited to one single failure pathway, but may develop through several different parts of the well system depending on well construction, abandonment design, and later material degradation. As shown in the figure,

potential migration pathways include cement channels, plug microannuli, inner and outer microannuli, casing corrosion, leakage into off-target formations, and seal fracturing. The figure also shows that leakage risk depends on the degree of barrier continuity: in the highest-risk case, reservoir fluids can migrate upward through an uncemented annulus with little resistance, whereas in lower-risk cases fluids must pass through increasing lengths of annular cement and a greater number of plugs. (Lackey et al., 2026).

Recent studies evaluating CO_2 projects have emphasized the importance of assessing legacy well infrastructure as part of site screening and risk management. In federal offshore waters along the Texas Gulf Coast, the main concern is offshore wells' original completion and plugging designs that were commonly intended to isolate hydrocarbon-producing intervals rather than the non-productive intervals that may later be selected for CO_2 storage. A well that was completed and plugged appropriately for its original oil and gas purpose may still lack barriers in the locations needed to isolate a future storage target if injection is planned in different stratigraphic zones. (Lackey et al., 2024).

1.2. PROBLEM STATEMENT

Many sedimentary basins suitable for carbon storage have been extensively explored and developed for oil and gas production, resulting in large numbers of existing wells that penetrate both storage intervals and overlying confining units. These legacy wells may intersect intervals important to containment and therefore represent potential pathways through which fluids could migrate from the storage reservoir to overlying formations or the surface (Watson & Bachu, 2009). Wellbores may provide leakage pathways if well construction or abandonment materials degrade over time. Potential mechanisms include poorly cemented casing-formation interfaces, casing corrosion, or incomplete isolation during well abandonment. When a driving force such as buoyancy or pressure buildup from CO_2 injection exists, these pathways can allow fluids to migrate along the wellbore and bypass otherwise effective confining units (Watson & Bachu, 2009).

Because of these concerns, CCS regulatory frameworks and research studies emphasize evaluation of legacy wells within the AoR surrounding a storage project. Current risk-assessment approaches often rely on probabilistic and uncertainty-based methods to identify potential leakage pathways and rank risks associated with subsurface processes. However, these frameworks frequently depend on theoretical assumptions and simplified models because direct observations of CO_2 leakage through legacy wells remain limited (Celia et al., 2011).

1.3. RESEARCH GOALS

The primary goal of this research is to develop an evidence-based framework for evaluating legacy well risks associated with geologic CO_2 storage in the Gulf Coast Basin. The study focuses on how legacy wells should be identified, screened, and classified within CCS risk assessment frameworks.

This research seeks to answer the following key questions:

- How should legacy wells be evaluated within CCS risk assessment frameworks for CO_2 storage projects?
- What empirical evidence exists from historical well failure records that is relevant to evaluating potential leakage pathways associated with legacy wells?
- What insights from underground injection operations can inform the evaluation of legacy well integrity in CCS projects?

- How can legacy well risk classification frameworks be calibrated using empirical evidence and operational experience?

1.4. RESEARCH METHODOLOGY

This study applies a multi-stage methodology to evaluate legacy well risks associated with geologic CO_2 storage in the Gulf Coast Basin. The workflow consists of five main components: (1) literature review and framework comparison, (2) legacy well dataset analysis, (3) historical well failure dataset analysis, (4) comparison with Class I injection experience, and (5) development of a conceptual testing framework for borehole sealing processes.

Literature Review and Framework Comparison

The first component involves a review of existing legacy well risk classification frameworks used in CCS studies. The review identifies the indicators most commonly used to evaluate legacy wells. It also examines how different studies treat incomplete records and uncertainty related to historical drilling and abandonment practices. Comparing these approaches provides a basis for identifying their similarities, limitations, and the need for calibration using empirical evidence.

Legacy Well Dataset Analysis

The second component evaluates the legacy well population in the Gulf Coast Basin. This part of the study analyzes key well attributes, including well type, spud date, depth, and orientation, in order to characterize the population relevant to CO_2 storage screening. The purpose is to understand how screening frameworks are applied to large well populations and how different well characteristics may influence classification outcomes.

Well Failure Dataset Analysis

The third component evaluates historical well control incident data to better understand the types of failures that have occurred during oil and gas operations. The analysis identifies dominant failure mechanisms and distinguishes temporary operational incidents from failures that may indicate longer-term well integrity concerns. By examining the frequency and character of these incidents, the study develops an empirical basis for assessing whether assumptions used in legacy well classification frameworks are consistent with observed operational behavior.

Comparison with Class I Injection Experience

The fourth component examines operational experience from underground injection activities, particularly Class I disposal wells. This part of the study evaluates how injection operations address pressure communication, hydraulic isolation, and the identification of realistic migration pathways. Comparing CCS legacy well assumptions with Class I injection experience helps assess whether current CCS interpretations are consistent with operational evidence.

Conceptual Field Testing Framework

The final component develops a conceptual framework for field-scale testing of borehole sealing processes relevant to CO_2 storage. This part of the study is motivated by observations from the Orange Borehole Closure experiment, which showed that clay-rich formations surrounding an open borehole may deform over time and restrict fluid migration pathways. Building on this idea, the study proposes a conceptual testing approach for evaluating borehole closure behavior under conditions representative of CO_2 storage systems. Although no field experiments are conducted directly in this research, the proposed framework provides a basis for future work aimed at improving calibration of legacy well classification methods and understanding borehole sealing behavior in clay-rich sedimentary environments.

Figure 2. Research Methodology Framework.

CHAPTER II: BACKGROUND

2.1. INTRODUCTION

The Gulf Coast Basin provides one of the most important geologic settings in the United States for evaluating both CO_2 storage opportunity and legacy well risk because basin-scale stratigraphy, confining-zone continuity, and a long petroleum development history are tightly linked. The U.S. Gulf Coast contains a regionally extensive and thick sedimentary succession of clastics, carbonates, salts, and other evaporites deposited under cyclic depositional conditions influenced by fluctuating siliciclastic sediment supply and transgressive-regressive sea-level changes. At least nine major depositional packages in the region contain porous strata potentially suitable for geologic CO_2 sequestration. Storage evaluation therefore depends on reservoir depth, thickness, porosity, permeability, groundwater salinity, and the character of the overlying regional confining zone (Roberts-Ashby et al., 2014b).

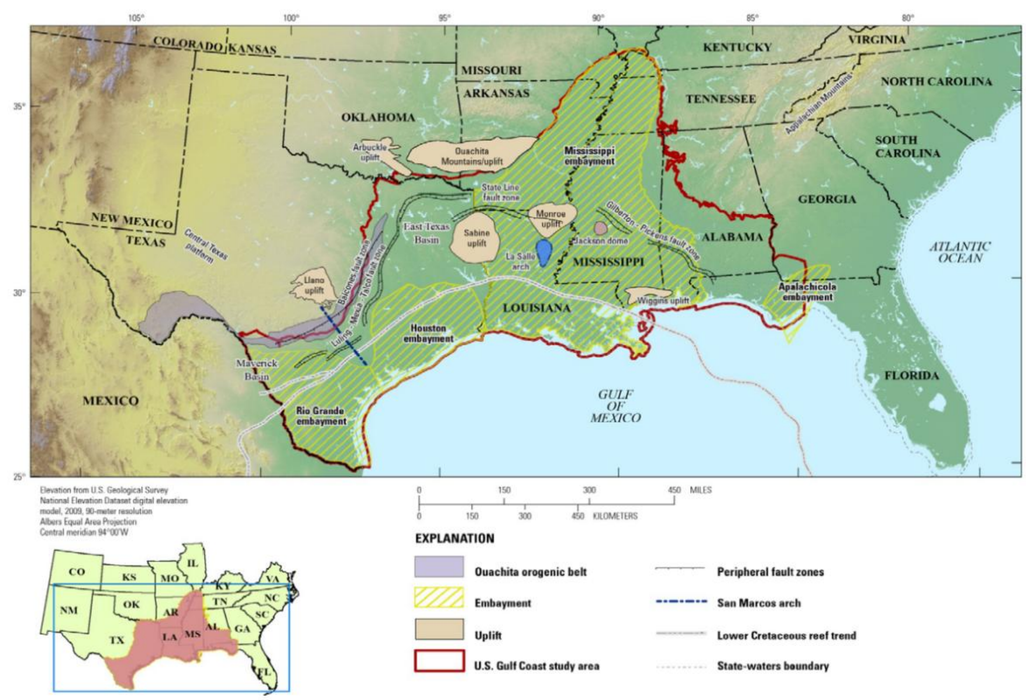

Figure 3. Regional extent of the U.S. Gulf Coast study area and major basin-scale structural and geographic elements referenced in this chapter (adapted from Roberts-Ashby et al., 2014b).

The Oligocene Frio and Anahuac Formations provide a particularly useful example of reservoir-confining-zone architecture in the Gulf Coast Basin. Swanson et al. (2013b) describe the Frio Formation as a sand-rich fluvio-deltaic system and one of the largest hydrocarbon producers from the Paleogene in the Gulf of Mexico, whereas the overlying Anahuac Formation is described as an extensive transgressive marine shale. In downdip parts of the basin, the Frio and Anahuac intervals are associated with faulted rollover anticlines, salt-related structures, and combined structural and stratigraphic traps.

From a CO_2 storage perspective, the Frio-Anahuac relationship illustrates the vertical pairing of porous reservoir intervals and regionally extensive confining facies. Roberts-Ashby et al. (2014b) describe the Vicksburg-Frio interval as a southeast-dipping siliciclastic package deposited along the Gulf of Mexico continental margin during the Oligocene, whereas the overlying Anahuac Formation consists mainly of fine-grained open-marine deposits that are several hundred feet thick and may approach 1,000 ft in some areas. Roberts-Ashby et al. (2014b) interpret the Anahuac as a robust regional upper confining zone for prospective CO_2 storage in Vicksburg-Frio reservoirs.

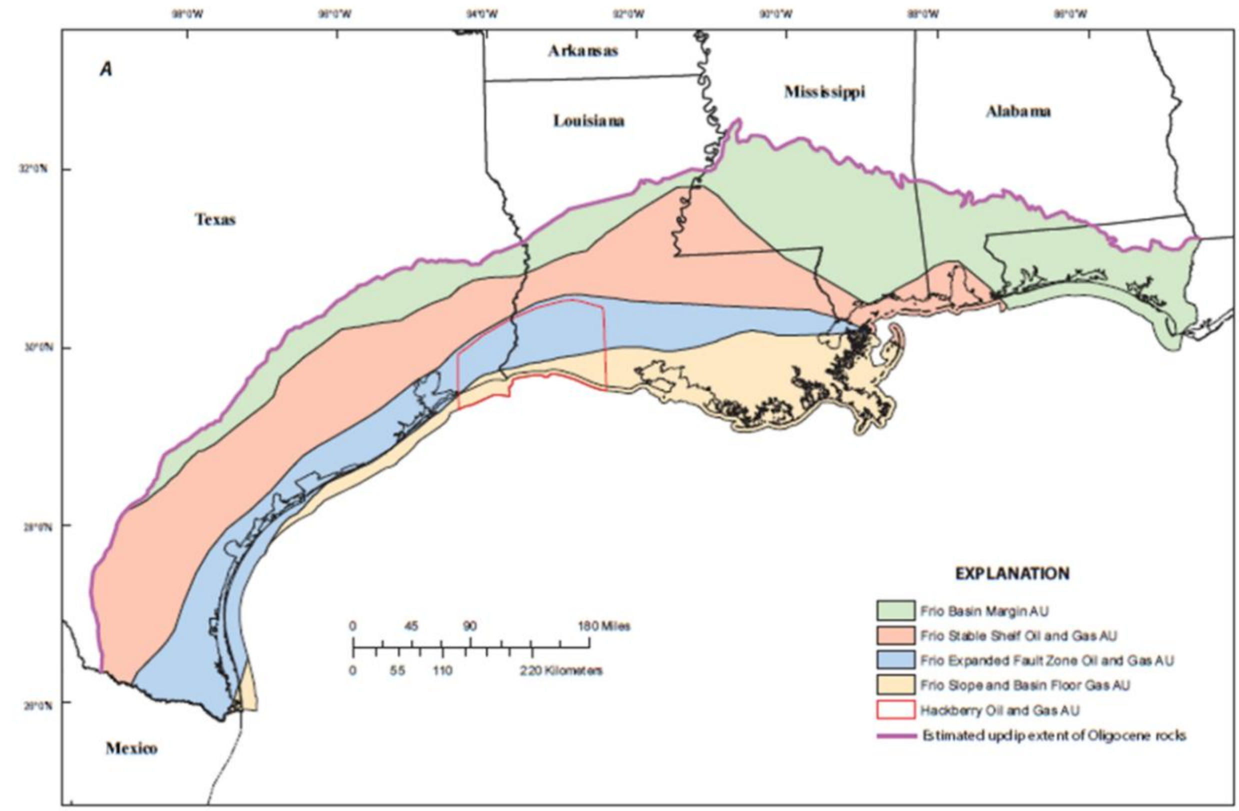

Figure 4. Regional distribution of Frio assessment units across the Gulf Coast Basin, illustrating the basinward transition from basin-margin and stable-shelf settings into expanded-fault-zone and slope-to-basin-floor settings within the Oligocene section (adapted from Swanson et al., 2013b).

However, the Gulf Coast Basin is not only a prospective storage province; it is also one of the most intensively developed petroleum provinces in North America. Many prospective storage intervals have already been penetrated by legacy wells drilled and abandoned under a wide range of technical and regulatory standards. Lackey et al. (2026) identify leakage as the primary concern associated with legacy wells at geologic carbon storage sites and note that pre-existing wells that penetrate CO_2 injection reservoirs or their overlying confining zones may provide direct pathways for CO_2 or displaced formation fluids to escape the intended storage system. This issue is especially important in the Gulf Coast Basin.

2.2. GEOLOGICAL FRAMEWORK OF THE GULF COAST BASIN

The Gulf Coast Basin is a large, long-lived sedimentary basin characterized by thick Mesozoic and Cenozoic successions that deepen and dip basinward toward the Gulf of Mexico. Regional stratigraphic relations documented by Baker et al. (1995b) show that Gulf Coastal Plain strata form a laterally extensive and vertically stacked succession in which numerous formations can be traced from updip outcrop belts into the deep subsurface, demonstrating the thickness and continuity of the basin fill. In the context of CO_2 storage, this architecture is important because storage intervals in the Gulf Coast are not isolated geologic bodies, but parts of a basin-scale stratigraphic system in which porous reservoir units are cyclically overlain by finer-grained confining intervals. Roberts-Ashby et al. (2014b) formalized this logic at the storage-assessment scale by defining storage assessment units as paired reservoir–confining-zone systems, emphasizing that the operational geologic unit for storage evaluation is a porous formation coupled with an overlying fine-grained confining zone.

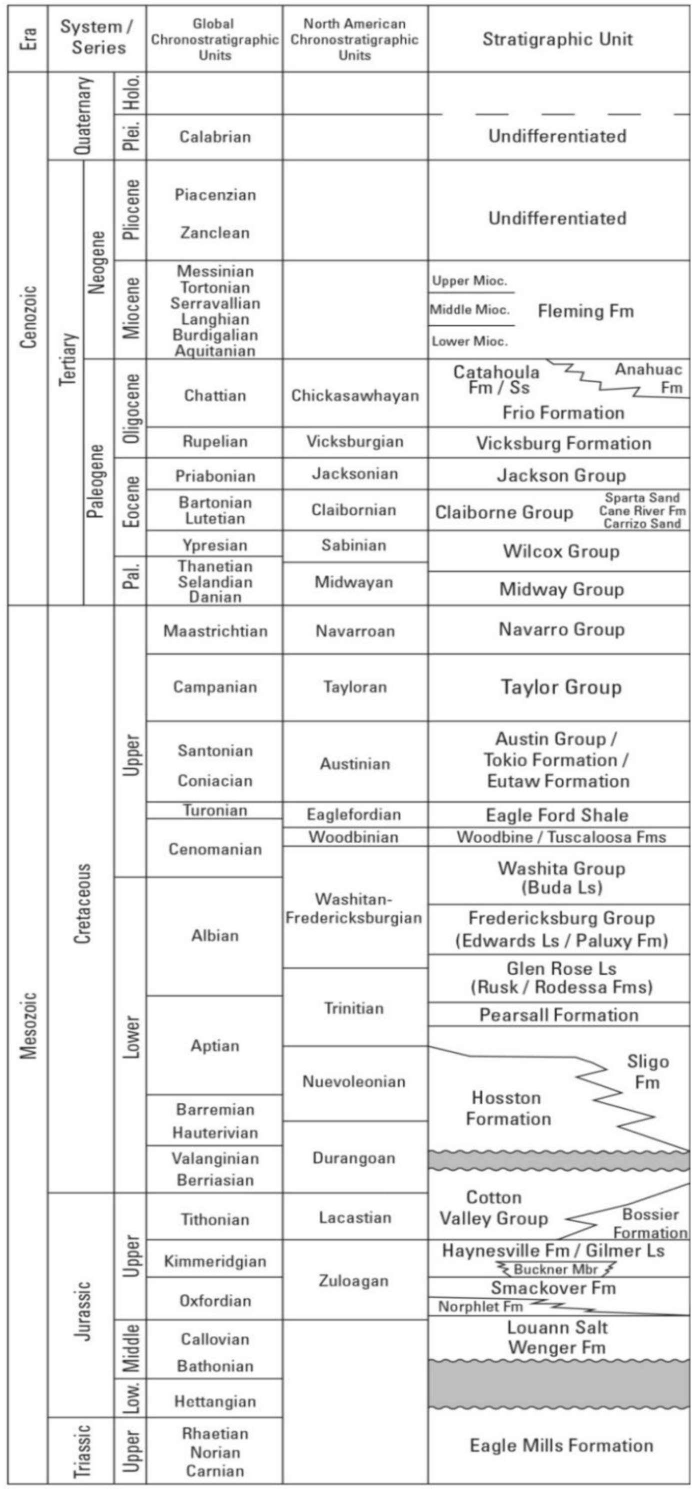

Figure 5. Regional stratigraphic framework of the Gulf Coast Basin, showing major Mesozoic and Cenozoic stratigraphic units relevant to storage assessment (adapted from Roberts-Ashby et al., 2014b, Fig. 2A).

Within this broad basin framework, the Oligocene Frio and Anahuac interval provides one of the clearest examples of Gulf Coast reservoir–confining-zone architecture. Swanson et al. (2013b) describe the Frio Formation as one of the major Tertiary progradational wedges of the Texas Gulf Coastal Plain, deposited during a period of major clastic influx related to uplift, erosion, and sediment delivery from Mexico and the southwestern United States. Their synthesis shows that Frio deposition was organized along several major sediment-dispersal axes, including the Norias, Norma, Houston, and central Mississippi systems, which supplied fluvial, deltaic, shoreface, shelf, and deeper-water facies across the basin. Roberts-Ashby et al. (2014b) similarly describe the Vicksburg–Frio package as a southeast-dipping siliciclastic succession deposited along the Gulf of Mexico continental margin in a range of depositional environments, including distributary channel, delta plain, delta, interdeltaic embayment, and continental shelf settings. Together, these studies show that the Frio is a regionally extensive siliciclastic wedge composed of multiple stacked depositional environments and reservoir facies.

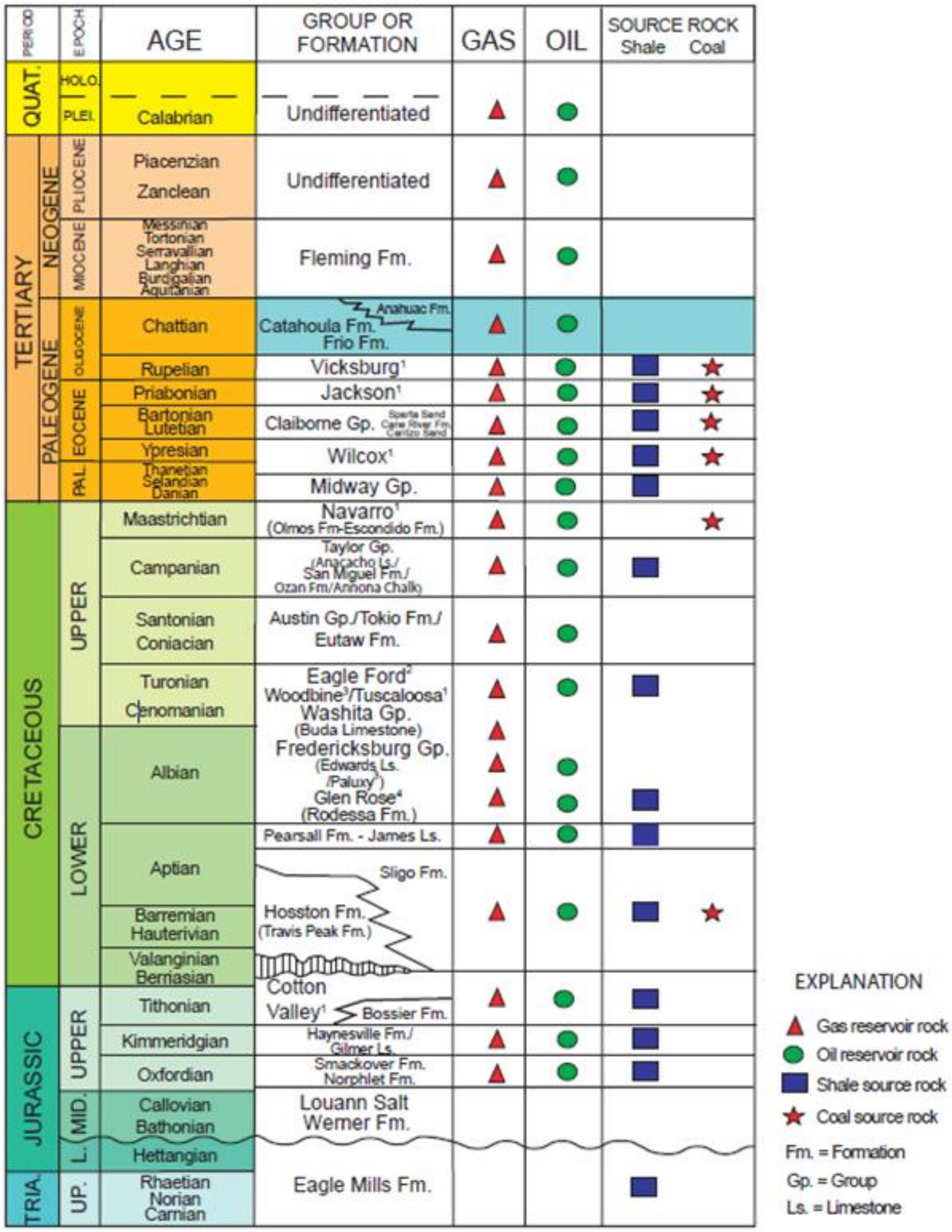

Figure 6. Stratigraphic position of the Frio and Anahuac Formations within the northern Gulf of Mexico Coastal Plain (adapted from Swanson et al., 2013b).

The overlying Anahuac Formation represents the main regional confining interval for much of the Oligocene storage section. Roberts-Ashby et al. (2014b) identify the Anahuac as a retrogradational systems tract composed mainly of fine-grained, open-marine deposits overlying the Vicksburg and Frio Formations. Anahuac is regionally several hundred feet thick and may approach 1,000 ft in some areas, making it a robust regional upper confining zone for prospective CO_2 storage in Vicksburg–Frio reservoirs. Swanson et al. (2013b) likewise describe the Anahuac as an extensive transgressive marine shale overlying the Frio, while also noting that downdip equivalents may include slope sandstones in Texas and Louisiana. For storage evaluation, this means that the Gulf Coast Basin contains a vertically stacked arrangement in which sandstone-dominated reservoir intervals are commonly overlain by marine shale-prone confining facies, although lateral facies variability must still be recognized during site-specific assessment.

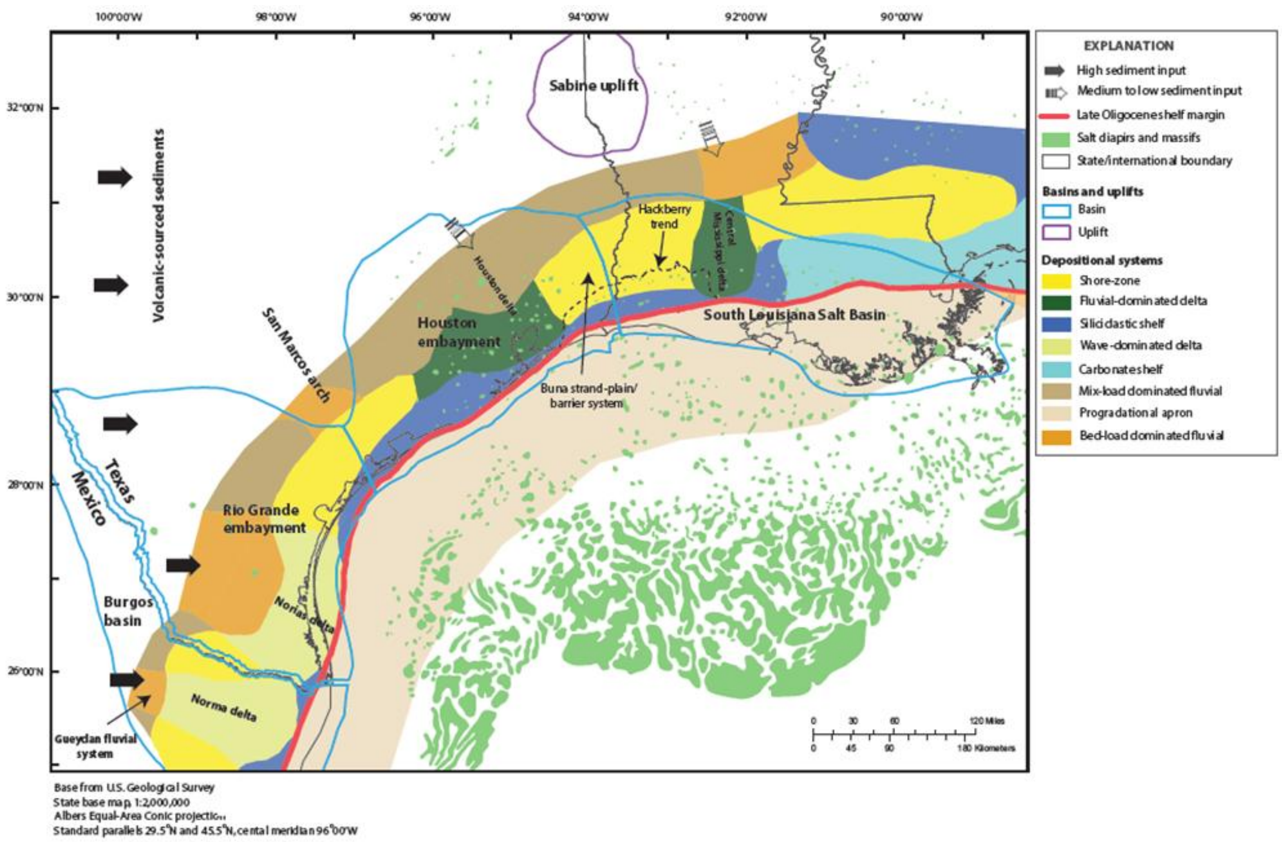

Figure 7. Major late Oligocene sediment-dispersal systems that contributed to construction of the Frio wedge across the Gulf Coast Basin (adapted from Swanson et al., 2013b).

This stacked architecture is further shaped by syndepositional growth faulting, salt tectonism, and rapid progradation. Swanson et al. (2013b) emphasize that downdip Frio and

Anahuac traps commonly occur in association with faulted rollover anticlines, salt-related structures, and combined structural and stratigraphic trapping styles. Major Frio thickening and displacement across the Vicksburg and Frio fault zones, indicating that accommodation development, sediment loading, and syndepositional deformation were central to basin evolution. As a result, Gulf Coast stratigraphy should be understood as a structurally segmented basin in which reservoir quality, thickness, confining-zone continuity, and migration pathways vary across shelf, fault-zone, slope, and basin-floor settings.

Figure 8. Cross section showing the influence of syndepositional growth faulting and basin segmentation on Frio and Anahuac stratigraphic architecture across the Gulf Coast Basin (adapted from Swanson et al., 2013b).

From a CO_2 storage perspective, these geologic relations are favorable because they provide multiple reservoir–confining-zone pairs across a broad depth range. Roberts-Ashby et al. (2014b) note that the Frio and Vicksburg storage assessment unit is bounded in part by the 3,000 and 13,000-ft depth-to-top contours, which define parts of the updip and downdip limits of the storage assessment unit and broadly correspond to the depth range most relevant to supercritical CO_2 storage and injection feasibility.

An additional aspect of the geological framework relevant to legacy well risk is the mineralogical and diagenetic evolution of Frio mudrocks. In this chapter, the term mudrock is used for fine-grained Frio rocks, whereas clay mineral refers specifically to constituents such as illite, smectite, and mixed-layer illite/smectite. Lynch et al. (1997) analyzed mixed-layer illite/smectite from Frio mudrock cores on the Texas Gulf Coast and showed that, between about 7,000 and 15,000 ft burial depth, the clay-mineral assemblage evolves from more smectite-rich, randomly interstratified material to more ordered and illite-rich compositions. This transformation is a dissolution–reprecipitation process. Mass-balance calculations indicate that this clay-mineral diagenesis was an open-system process involving addition of K_2O and Al_2O_3 and loss of SiO_2, and that silica released during diagenesis was sufficient to contribute to quartz-overgrowth cement in associated Frio sandstones. These observations show that Frio mudrocks are chemically evolving materials whose burial history can influence fluid flow, reservoir diagenesis, and the mechanical behavior of formations penetrated by wells.

More broadly, clay-mineral abundance in Frio mudrocks is important to both basin evolution and well integrity. Lynch et al. (1997) note that fine-grained rocks are volumetrically dominant in the Frio Formation and related Gulf Coast Cenozoic units, and that illite, smectite, and mixed-layer illite/smectite are major mineral constituents of these mudrocks.

2.3. CLASS VI STORAGE CONTEXT AND RELEVANCE OF LEGACY WELLS

Under the U.S. Class VI Underground Injection Control framework, geologic CO_2 storage projects must demonstrate that injected CO_2 and displaced formation fluids will remain confined within the intended storage system and will not endanger underground sources of drinking water. This requirement extends beyond the injection interval itself and includes the surrounding AoR, which is defined based on the predicted movement of the CO_2 plume and associated pressure front. Within that area, operators must identify wells and other artificial penetrations and evaluate whether they could serve as conduits for vertical fluid movement under storage conditions (Office of Water (4605M), 2013c).

This regulatory logic means legacy wells are not screened only by age or number. They are screened in relation to storage-system relevance. A well becomes important when it intersects the storage interval or relevant confining units, lies within the pressure-affected system, and contains a plausible migration pathway that could transmit CO_2 or displaced fluids upward. In other words, not all old wells are equally relevant to a storage project. The key question is whether the well is hydraulically and geometrically connected to the part of the subsurface that matters for containment.

2.4. BASIC WELL CONSTRUCTION, FAILURE PATHWAYS, AND MULTI-ZONE LEAKAGE

Basic Well Construction and Zonal Isolation

A well is built to keep fluids in the right interval and stop them from moving between subsurface zones. This starts during drilling, when drilling fluids help control pressure and keep the borehole stable. It continues during completion, when casing, cement, packers, tubing, and wellhead equipment are installed to form the main barrier system. In a properly built well, these barriers are meant to stop fluids from mixing between formations and to allow injection or production only from the target zone (Porse et al., 2014; King, n.d).

Most oil and gas wells are constructed in stages, with progressively smaller casing strings set as the well deepens. Surface casing is typically cemented below the deepest protected groundwater zone, while intermediate and production casing are installed as needed to maintain pressure control and isolate deeper formations. In this system, steel casing provides structural support, and cement placed in the annulus provides the primary hydraulic seal outside the pipe (King, n.d.; Arthur and Technology Subgroup, 2011).

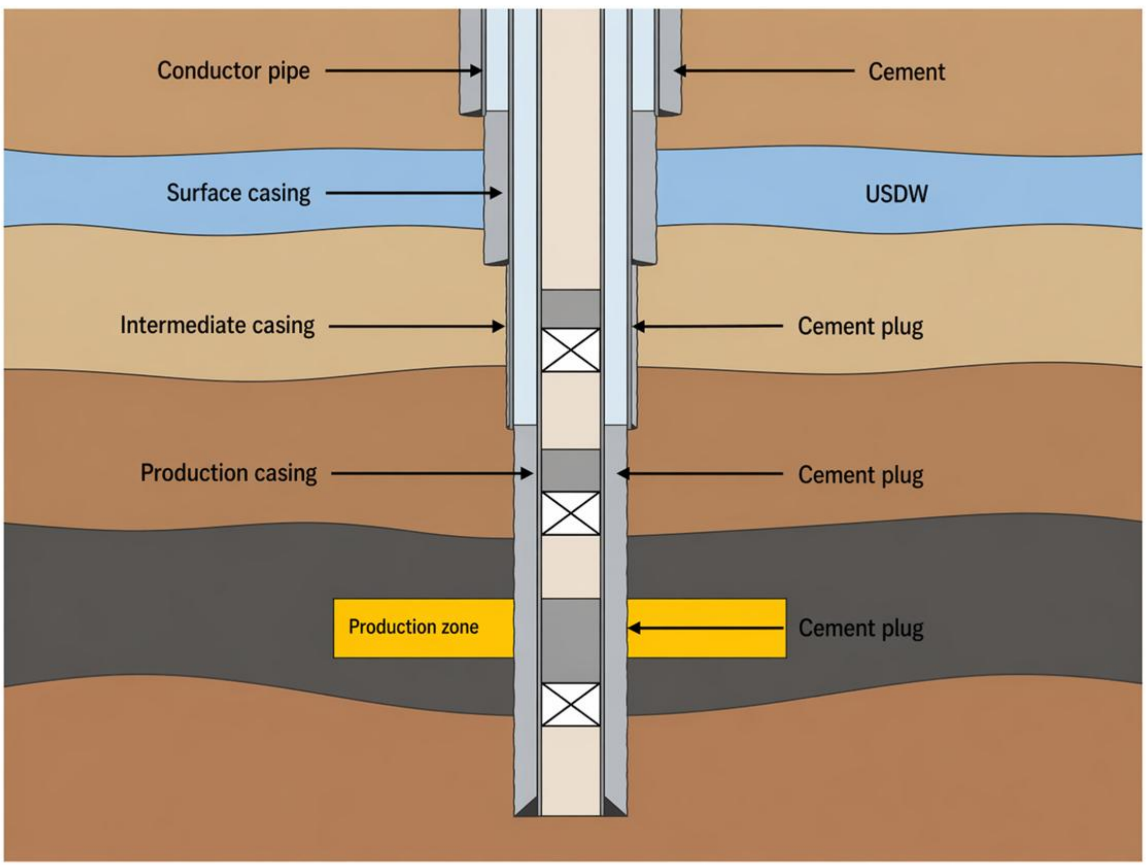

Figure 9. Simplified schematic of well barrier architecture showing conductor, surface, intermediate, and production casing; annular cement; and cement plugs used to isolate shallow groundwater, the production interval, and other subsurface zones during well completion and abandonment.

For that reason, cement quality is just as important as the casing itself. Cement in the annulus is intended to isolate formations outside the pipe, while additional testing and evaluation are used to check whether the seal was placed and bonded properly after cementing (King, n.d.; Freifeld et al., 2016).

The same barrier idea applies when a well is plugged and abandoned. Plugging is not just stopping operations. It is the last stage of building barriers after the well is no longer in use. Cement and, in some cases, mechanical plugs are placed across producing zones, groundwater-bearing intervals, casing shoes, and near-surface sections so that fluids cannot move upward later. Because cement is the main long-term sealing material, the future performance of a legacy well depends heavily on whether plugs were placed in the right intervals and installed well enough to keep formations separated over time (Arthur and Technology Subgroup, 2011; J. Daniel Arthur et al., 2011c).

This is especially important for older wells. Many were drilled and abandoned before modern plugging rules, groundwater-protection standards, and cementing practices were fully developed. Historical reviews show that early practices were often inconsistent and sometimes used very little cement or materials that would not meet current standards. For that reason, the presence of an old plug does not automatically mean that a well can still isolate formations under modern CO_2 storage conditions. In legacy-well assessment, plugging vintage is therefore a real source of uncertainty, not just a historical detail (J. Daniel Arthur et al., 2011c; Chukwuemeka et al., 2023; Tintera and Savage, 2006).

Common Well Failure Pathways

Understanding how wells are built to provide isolation also requires understanding how that isolation can break down. Porse et al. (2014) defines loss of well control broadly as unintended fluid movement through or along the well system, either into other formations or to the surface. This definition shows that integrity failure is not limited to dramatic surface blowouts. A well may lose containment in the subsurface before any release becomes visible, and in storage settings that alone can represent barrier failure (Porse et al., 2014; Freifeld et al., 2016).

Several pathways can cause a well to lose isolation. Common examples include poor cement bonding, incomplete sealing in the annulus, casing corrosion, tubing or packer failure, and the degradation of plugged and abandoned wells. Such problems may result from poor initial construction, mechanical damage, long-term aging, pressure changes, or operational error. In most cases, failure does not arise from one isolated defect, but from the combined effects of barrier quality, well history, and later operating conditions (Porse et al., 2014; Bérest et al., 2019; Freifeld et al., 2016).

Loss of integrity may also originate much earlier than the production or abandonment stage. If the borehole wall is unstable during drilling, casing placement and cementing can be compromised from the start. An irregular or damaged annulus may leave discontinuous cement, weak bonding, or channels that persist long after the well is completed. For that reason, some later leakage problems are rooted in the original drilling and cementing environment (Porse et al., 2014).

Multi-Zone Isolation and Secondary Leakage Pathways

In CCS projects, it is not enough to ask whether a well was built for the original hydrocarbon-producing zone. The more important question is whether the well is isolated across the zones that matter for the future storage project. This is especially important in the Gulf Coast, where oil or gas may have been produced from one interval, while CO_2 injection may later be planned in another. For example, a well that was completed to isolate a Frio hydrocarbon interval may not necessarily isolate a planned Miocene storage interval if cement was not placed across the formations that now matter for containment. For this reason, legacy-well assessment should consider not only where a well originally produced, but whether its casing and cement system also protect the future injection interval and any formations above it that could later become involved (Lackey et al., 2026c; Arthur and Technology Subgroup, 2011).

Another important point is that leakage does not always move straight from a deep injection zone to the surface. In some cases, fluids or pressure first enter shallower formations and only later escape through faults, springs, outcrops, or older wells. Heath et al. (2009), in their study of the Salt Wash and Little Grand Wash CO_2 system in Utah, showed that CO_2 can rise from a source deeper than 800 m, move into shallower stacked aquifers, partly dissolve into groundwater, and later discharge through faults, springs, geysers, and abandoned wells. This shows that shallower zones can become charged before any final surface release occurs, which makes leakage more difficult to trace to one simple pathway (Heath et al., 2009).

Karanam et al. (2024) provide a modern example that leads to the same conclusion. In their Permian Basin study, deeper wastewater injection was interpreted to have increased pressure in shallower formations, where an over-pressured aquifer later discharged through an aged well. Their results showed surface uplift of about 20 cm per year, total uplift of about 40 cm in two years, about 3 cm of subsidence in two weeks during the January 2022 blowout, and excess pressure greater than 3 MPa in the shallow aquifer. In that case, the failing well did not need to intersect the main injection zone to become important. It became a leakage pathway because pressure and fluids had been redistributed into shallower connected units (Karanam et al., 2024).

A related example from the Salt Creek field in Wyoming shows how older abandoned wells can become secondary release pathways in pressure-managed CO2 fields. Toxic gases entered the Midwest School through an abandoned well associated with a nearby CO2-flooded field. The reported well had been drilled in the 1920s, plugged in the mid-1980s, and later acted as a conduit for gases linked to the injected field. It shows that legacy wells outside the primary target interval can still provide a migration path once pressure and fluids are redistributed through the subsurface (Wirfs-Brock, 2016).

Recent West Texas blowouts point to the same broader problem: subsurface pressure redistribution can shift discharge toward older weak points rather than a single originally identified pathway. Reporting on the 2022 Crane County geyser described a 1,390-ft-deep dry hole drilled in 1948 and plugged in 1957 that later discharged an estimated 25,000 barrels of briny water per day. Pressurized saline water may have migrated upward and eroded the cement plugs in the old well, allowing flow to reach the surface. Although this was not a CO_2-storage case, it illustrates how older plugged wells can become release points when subsurface pressure is transmitted into connected shallower units (Gold, 2022).

These examples show that legacy-well assessment should not focus only on the original production interval. Cement placement across the future storage system may matter just as much, and in some cases more. A well may appear acceptable if judged only by its historical target zone, yet still remain a leakage concern if its cement does not isolate overlying or laterally connected units that could become involved during CO_2 injection (Lackey et al., 2026).

2.5. EMPIRICAL LEAKAGE EXPERIENCE RELEVANT TO STORAGE SYSTEMS

Where empirical experience comes from, and why it matters

Most evidence on leakage and containment problems does not come from a large number of mature Class VI storage projects. Instead, it comes from hydrocarbon production, underground natural gas storage, gas fields, CO_2-EOR operations, and other subsurface systems in which pressure is actively managed. These settings are not identical to dedicated CO_2 storage, but they still provide operating experience with aging wells, barrier degradation, indirect leakage, and emergency response. Gas storage and gas fields also differ from Class VI storage in regulatory purpose and geologic history, including long periods of gas charge and the presence of multiple gas-bearing zones. Even so, they provide practical evidence of how wells fail, how pressure-managed systems behave, and how incomplete records and aging infrastructure complicate risk assessment (Porse et al., 2014; Freifeld et al., 2016; Michanowicz et al., 2017).

Natural Gas Storage and Hydrocarbon-Storage Analogues

Underground natural gas storage is one of the most useful analogues for long-term storage-well integrity because it combines repeated pressure changes, large well inventories, old infrastructure, and documented failures. Freifeld et al. (2016) make an important point here: storage integrity is not only a well-scale, but also a field-scale issue. It depends on barrier design, monitoring, diagnostics, record quality, and emergency response, not simply on the age of one well.

Michanowicz et al. (2017) identified 14,138 active underground natural gas storage wells at 317 active facilities in 29 states and found that 2,715 had been repurposed from earlier non-storage uses. These repurposed wells had a median age of 74 years, compared with 48 years for wells originally designed for storage. Of the repurposed wells, 2,694 were drilled before 1979, 661 before 1929, and an estimated 210 before 1917, before cement zonal-isolation practices were used. The majority, 88%, were concentrated in Ohio, Michigan, Pennsylvania, New York, and West Virginia. These numbers show that vulnerability is tied to the original purpose of the well and whether older barrier designs remain suitable for present-day storage conditions (Michanowicz et al., 2017).

The historical salt-cavern storage record provides another useful line of evidence. Bérest et al. (2019) reviewed twelve leakage incidents and found that many involved casing breach in intervals where one casing served as the main barrier between the stored product and surrounding formations. Corrosion, poor casing connections, and mechanically induced deformation were common causes. In many cases, hydrocarbons first accumulated in the subsurface before later reaching the surface. Pressure monitoring can help, but does not always provide enough warning on its own, and well design and regular tightness testing reduce the risk of casing leaks (Bérest et al., 2019).

The Yaggy/Hutchinson incident in Kansas provides a clear example of indirect leakage through secondary pathways. During the 2001 Hutchinson gas crisis, natural gas leaked from the Yaggy storage field and later appeared in Hutchinson through abandoned brine wells drilled decades earlier for salt production (Allison, 2001).

Aliso Canyon is one of the clearest examples of why aging storage wells matter. Freifeld et al. (2016) report that the blowout released about 100,000 tonnes of natural gas over roughly four months and displaced thousands of nearby residents. Michanowicz et al. (2017) use the same event to emphasize the importance of single-point-of-failure designs. These sources show that a well operating with limited barrier redundancy can create consequences far beyond the well itself, including regulatory scrutiny, public disruption, and national attention to storage-well integrity.

CO_2-EOR and Related Injection Experience

Porse et al. (2014) argue that CO_2-EOR provides one of the main real-world records for understanding CO_2-related loss of well control because it reflects decades of large-scale CO_2 handling, injection, and incidental storage. Using Texas Railroad Commission (RRC) data from Districts 3, 8, and 8A, Porse et al. (2014) found cumulative average blowout frequencies of 0.174% in District 3, 0.038% in District 8, and 0.062% in District 8A for the period 1998-2011. The stage with the highest blowout occurrence was not the same in every district: drilling was highest in District 3, while workovers were highest in Districts 8 and 8A. Higher CO_2 use did not show a simple positive relationship with overall blowout frequency. At the same time, many incident records lacked details such as failure depth, fluid type, leaked volume, or duration.

Offshore Legacy Wells as a Distinct Risk Context

Offshore legacy wells should be treated separately from onshore wells. Lackey et al. (2024) show that federal offshore waters in the Gulf of Mexico are attractive for large-scale CO_2 storage because they offer large storage resources, lie close to major coastal emission sources, and in many places have lower well density than onshore areas. At the same time, offshore storage would still have to deal with a very large inherited well population. More than 80,000 offshore oil and gas wells have been drilled in the Gulf of Mexico, and many of them were originally completed and abandoned to isolate hydrocarbon-producing intervals, not the nonproductive Miocene reservoirs that may now be considered for CO_2 storage. Their Galveston and Brazos case study also shows that offshore screening has to consider not only leakage risk, but also whether a well can realistically be accessed and remediated before storage begins.

In onshore settings, screening focuses strongly on groundwater protection and the possibility that brine or other fluids could migrate into USDW. Offshore, that same freshwater exposure pathway is not present at the surface. This does not make offshore leakage unimportant, but it shifts attention toward marine release pathways, storage containment performance, and the greater difficulty of corrective action or tieback once an offshore pathway is identified (Lackey et al., 2024e; Lackey et al., 2026c).

2.6. HISTORICAL PETROLEUM DEVELOPMENT AND EVOLVING WELL STANDARDS IN THE GULF COAST

The Gulf Coast petroleum industry developed over more than a century, beginning with early onshore discoveries and later expanding into marsh, shallow-water, and deepwater settings. Offshore expansion in the Gulf of Mexico was part of a broader response to declining onshore opportunities and, over time, added large numbers of increasingly complex wells to the regional inventory (Priest, 2007b). The historical transition most relevant to legacy well assessment is the evolution of plugging and abandonment standards. J. Daniel Arthur et al. (2011c) note that early oil and gas regulation was aimed primarily at protecting hydrocarbon resources rather than the environment, and that plugging rules lagged behind drilling and production practices. In Texas, the RRC did not gain authority over well plugging until 1919, by which time many wells had already been drilled with limited records of location or construction. Many wells drilled before the 1950s were either not plugged at all or were plugged with very little cement, and that vague requirements sometimes allowed the use of brush, wood, rocks, paper, and other improvised materials (J. Daniel Arthur et al., 2011c).

Chukwuemeka et al. (2023) similarly note that early abandonment practices were weakly regulated, that the 1919 Texas Railroad Commission requirements were designed mainly to prevent interstratal movement of reservoir fluids, and that stronger requirements for cementing and freshwater protection developed later (Chukwuemeka et al., 2023).

Texas provides a particularly important example because its rules evolved from general early plugging requirements into a more explicit groundwater-protection framework. Tintera and Savage (2006) state that Texas had pollution-prevention regulations as early as 1899, but plugging enforcement authority was not assigned to the RRC until 1919. Plugging standards were revised in 1957 to strengthen groundwater protection, that produced-water disposal to pits and surface waters was restricted beginning in 1955 and prohibited statewide in 1969, and that later regulatory development added stronger inspection, waste-management, and Underground Injection Control oversight. Texas also established dedicated state programs to plug abandoned wells with no responsible operator, including the Well Plugging Fund in 1965 and the broader Oil Field Cleanup Fund in 1991 (Tintera and Savage, 2006).

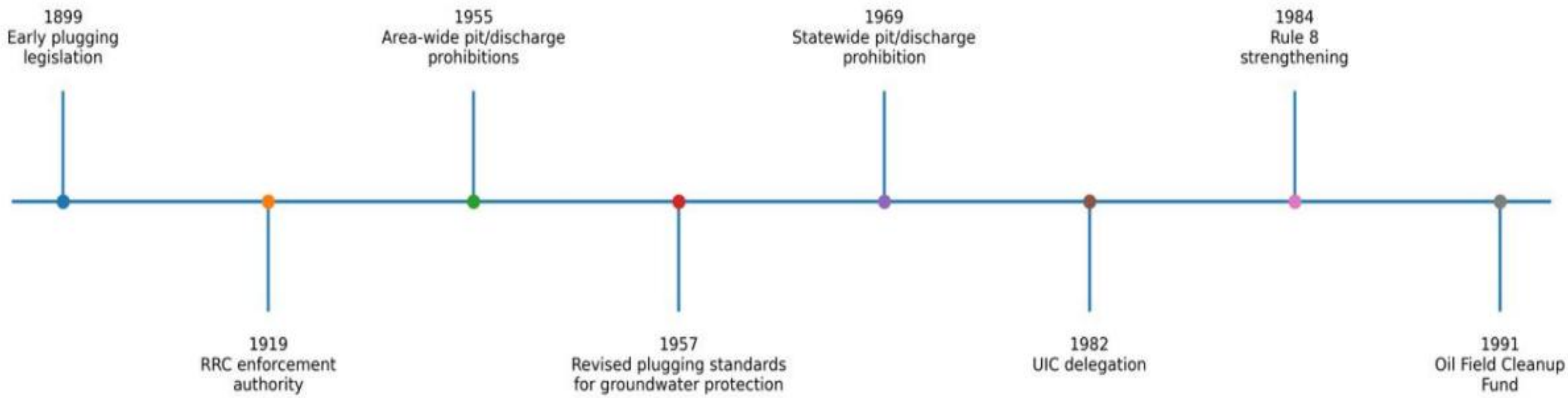

Figure 10. Timeline of key Texas regulatory milestones related to well plugging and groundwater protection. Source: author-created synthesis based on Tintera and Savage (2006).

The Gulf Coast legacy well population is therefore historically layered. Older wells may lack reliable records and may not have been designed or abandoned to isolate modern storage intervals or protected groundwater in the way current regulations require, whereas later wells generally reflect more standardized construction, cementing, and plugging practices. Petroleum development history matters here mainly because it produced the non-uniform well population that now complicates CCS screening, corrective action, and long-term containment assessment (J. Daniel Arthur et al., 2011c; Chukwuemeka et al., 2023; Tintera and Savage, 2006; Ground Water Protection Council, 2023e).

2.7. LEGACY WELL POPULATION IN THE GULF COAST

Spatial distribution of wells

Lackey et al. (2026c) report that, among 63 U.S. Class VI permit applications with publicly available legacy-well information, 534 legacy wells were identified, including 392 in the Gulf Coast Basin alone. This suggests that the Gulf Coast currently contains the largest basin-scale concentration of legacy wells in the U.S. Class VI permitting landscape.

The offshore component of this population is also substantial. Lackey et al. (2024e) state that more than 80,000 offshore oil and gas wells have been drilled in the Gulf of Mexico, with more than 45% located in federal waters and most already plugged and abandoned. Because offshore Gulf Coast CCS development is now being actively considered, this inherited well infrastructure is a major component of the regional storage context.

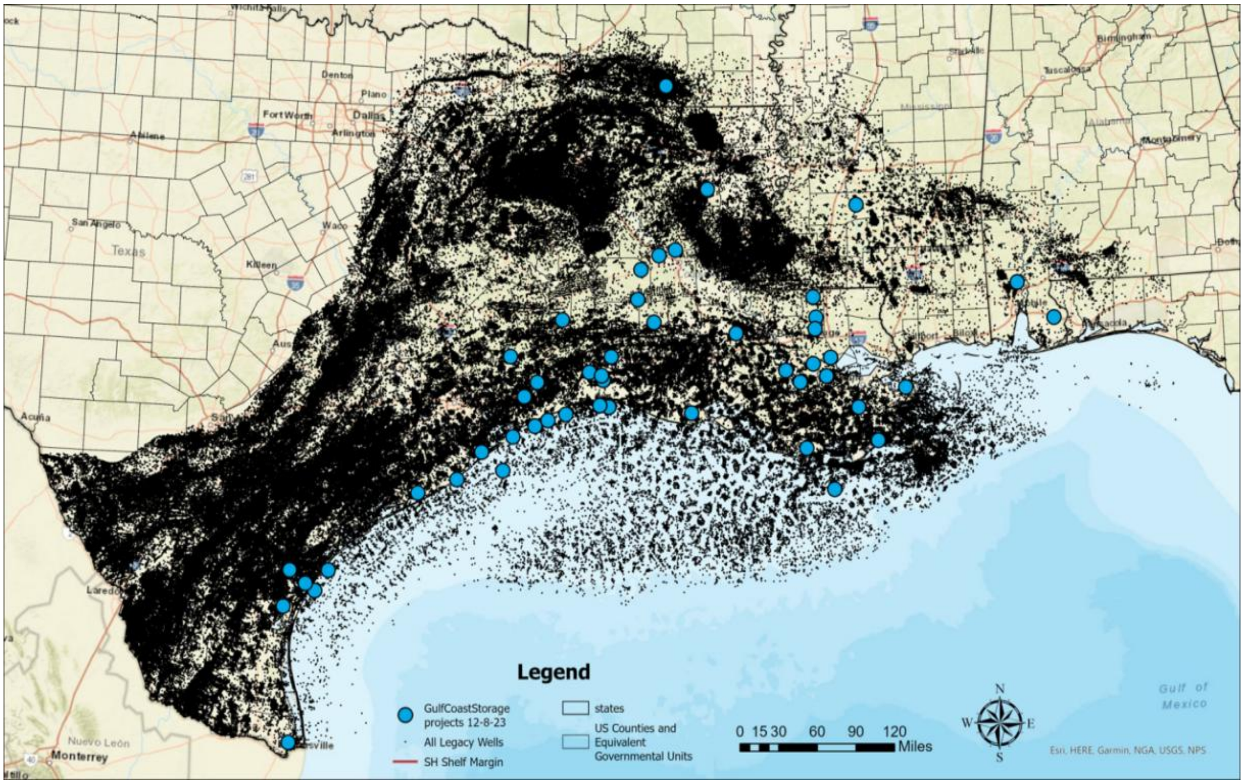

Figure 11. Distribution of legacy wells and CCS project locations in the Gulf Coast Basin (compiled from IHS data and project-location data; author's datasets).

Well Type Classification

In a typical oil or gas well, the first permanent engineered barrier is usually the surface casing, which is set and cemented to isolate usable groundwater, commonly to the base of protected water-bearing intervals. The borehole is then drilled to total depth under drilling-mud control, with mud providing temporary pressure control, cuttings transport, and borehole stability. If no economic resource is encountered, the well may never be fully cased and is instead abandoned by placing plugs across selected intervals. If the well is completed for production or injection, one or more additional casing strings are installed over part or most of the borehole and cemented in place. However, annular cement may not extend continuously to surface; in many wells, cement placement was designed mainly to isolate the producing interval and its overlying confining interval, leaving other annular sections mud-filled or only partly cemented. At the end of the well’s life, plugging and abandonment are intended to block potential flow pathways by placing cement and, in some cases, mechanical barriers across hydrocarbon-bearing zones, usable groundwater intervals, casing shoes, and other designated isolation points. These barrier configurations vary with reservoir type, basin conditions, drilling era, and regulatory requirements. In the Gulf Coast, thick siliciclastic successions, common use of multiple casing strings, and variable annular cement coverage mean that legacy wells may contain several possible pathway types, including flow through uncemented annuli, degraded cement interfaces, incompletely isolated intervals, or sections that were never fully cased (J. Daniel Arthur et al., 2011c; Chukwuemeka et al., 2023; Ground Water Protection Council, 2023e).

The Gulf Coast legacy well population is consists of multiple operational categories that reflect different service functions, construction histories, and abandonment outcomes. In this study, wells are grouped into producer wells, injection wells, dry and abandoned wells, plugged and abandoned wells, suspended wells, exploration or unknown wells, and a smaller residual “other” category.

Different well classes may be associated with different levels of record completeness, different likely casing and cement configurations, and different corrective-action needs. Producer and injection wells were drilled for active service and therefore often have more extensive completion records, although their final barrier condition still depends on later plugging or suspension history. Dry, abandoned, and exploration wells may be more difficult to evaluate because some were never fully completed, some may not include production casing, and their plugging details may be limited or inconsistent in the historical record. Suspended wells add further uncertainty because they may not yet have reached a final abandonment condition.

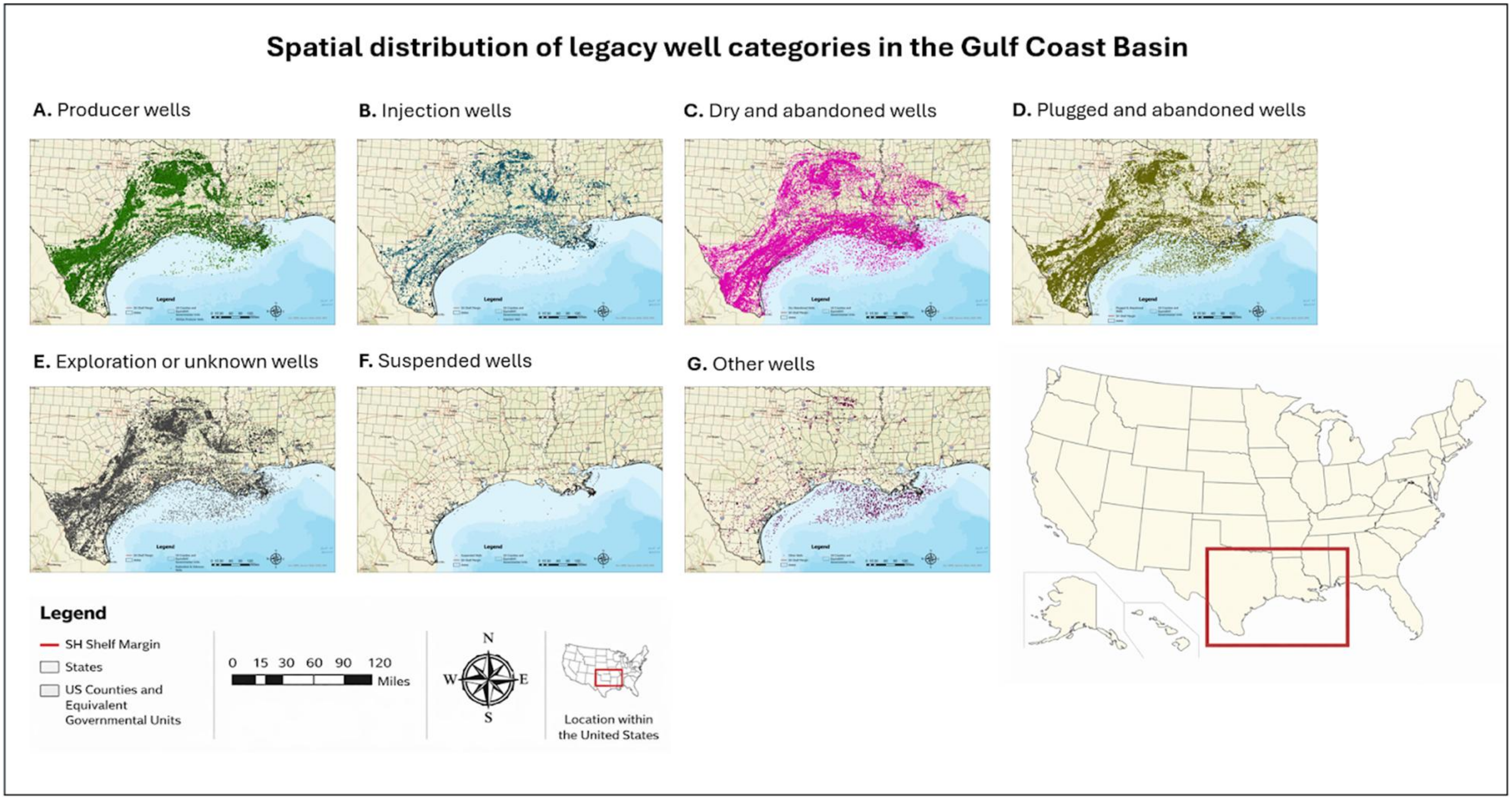

Figure 12. Spatial distribution of legacy well categories in the Gulf Coast Basin (compiled from IHS data; author's dataset).

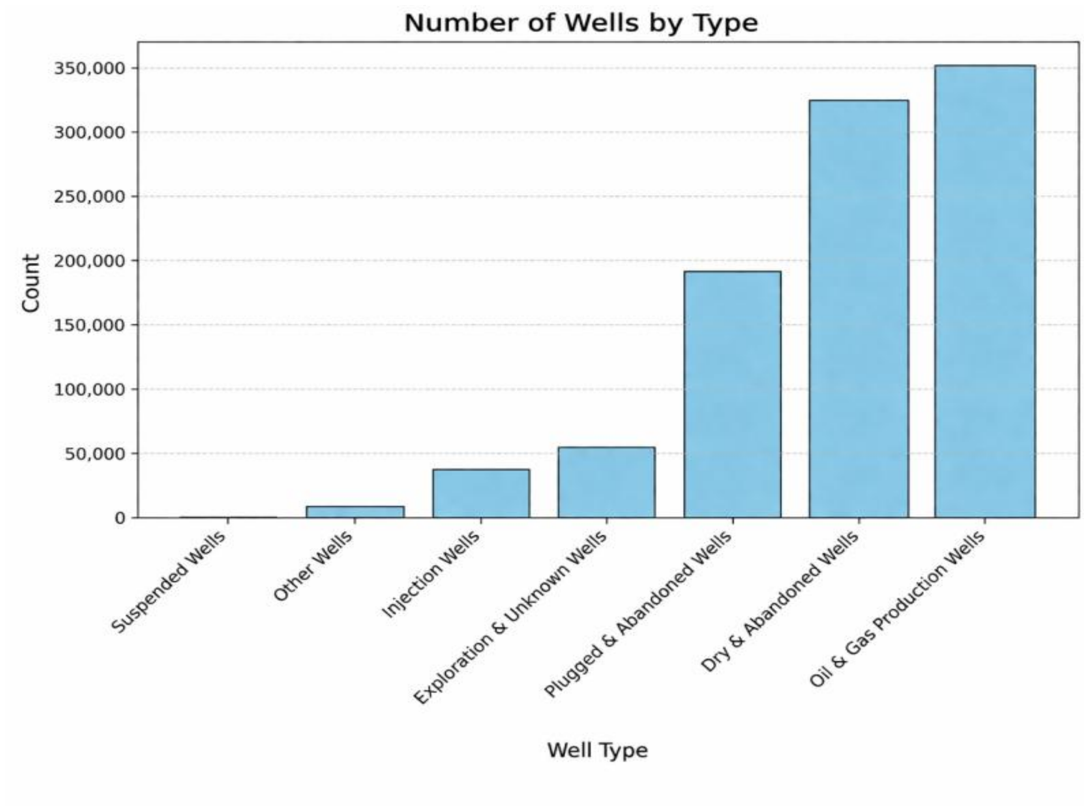

Figure 13. Distribution of legacy wells by operational type in the Gulf Coast Basin. The dataset is dominated by oil and gas production wells, followed by dry and abandoned wells and plugged and abandoned wells, while the remaining categories represent smaller fractions of the total well population. (compiled from IHS data; author's dataset).

Spud Date Distribution

Spud date, defined in the Enerdeq dataset as the date the drilling operations began on the well, is an important descriptive variable because Gulf Coast wells were drilled across multiple technical and regulatory eras (IHS Markit, 2018). In CCS screening, well age is commonly used as a proxy for construction practices, plugging design, and likely record completeness (Iyer et al., 2022d). In the Gulf Coast, older wells may also be associated with incomplete records, less accurate recorded locations, and greater uncertainty in historical construction and plugging details (Lackey et al., 2024e).

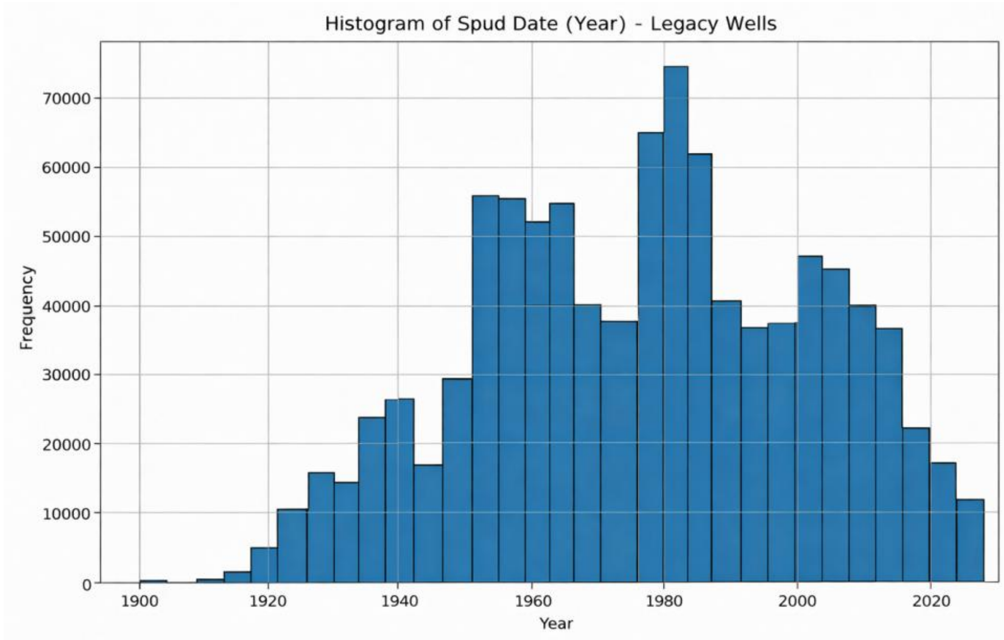

Figure 14. Spud-date distribution of legacy wells in the Gulf Coast Basin (compiled from IHS data; author's dataset).

Well Depth and Orientation Characteristics

Depth and orientation determine whether a well is likely to intersect prospective storage reservoirs, sealing formations, and future pressure footprints. Figure 15 shows that vertical wells dominate the Gulf Coast dataset, whereas directional and horizontal wells represent smaller portions of the population. An offshore Gulf Coast case study found that true vertical depths ranged from 918 to 6245 m, with a median of 2768 m, and that 97.2% of the wells in the study area penetrated the seal of the targeted Upper Miocene GCS interval (Lackey et al., 2024e).

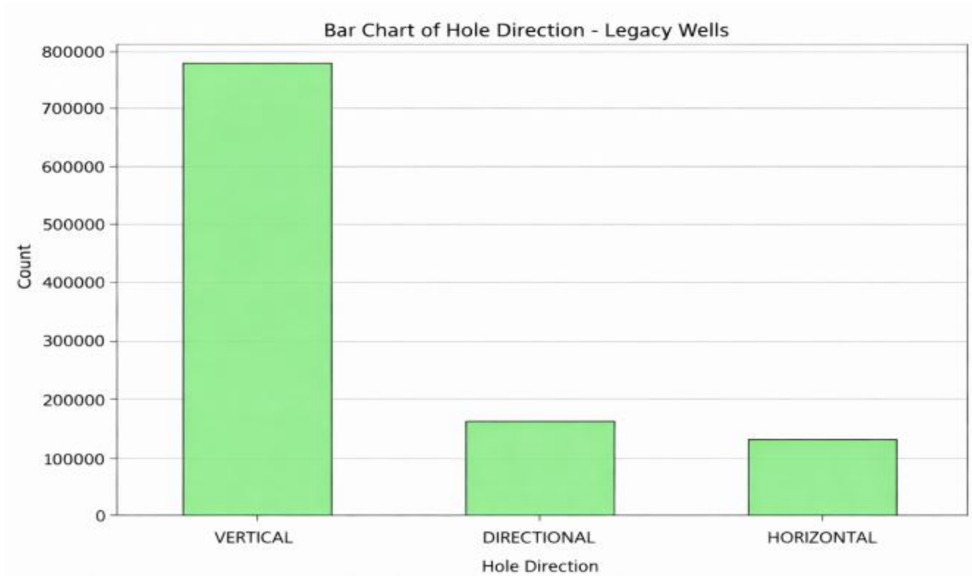

Figure 15. Hole-direction distributions of legacy wells in the Gulf Coast Basin (compiled from IHS data; author's dataset).

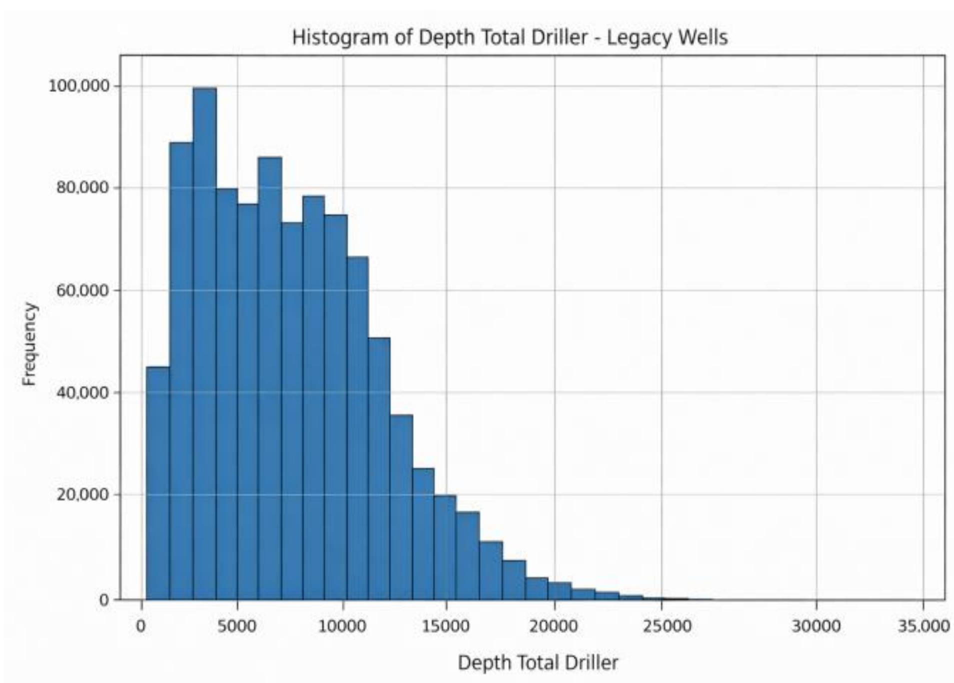

Figure 16. Total-depth distributions of legacy wells in the Gulf Coast Basin (compiled from IHS data; author's dataset's).

2.8. GEOLOGICAL FACTORS AFFECTING WELL INTEGRITY

Shale Compaction and Plastic Deformation

As discussed above, Frio mudrocks in the Gulf Coast Basin undergo burial-related clay-mineral diagenesis, including progressive transformation of mixed-layer illite/smectite with depth (Lynch et al., 1997). For well integrity, the important implication is that these fine-grained intervals are not mechanically static. Their burial history affects strength, stiffness, porosity, and deformation behavior, so the response of mudrocks around wellbores must be understood as part of a time-dependent basin process.

Late Tertiary mudstones are commonly more smectite-rich, whereas older rocks, especially mid to early Paleozoic shales, are more commonly illite-dominated. With burial and diagenesis, smectite progressively transforms to illite, and that shift changes shale response to water, swelling, and mechanical deformation. In practical terms, shales described in older drilling and wellbore-stability studies may be more indurated and more mineralogically evolved than the Cenozoic mudrocks typical of the Gulf Coast (Khodja et al., 2024; Lynch et al., 1997).

At the well scale, low-strength, ductile fine-grained intervals may gradually deform into open or poorly sealed annular spaces. Recent shale-as-a-barrier studies describe barrier-forming shales as materials with low stiffness, low strength, low friction angle, high porosity, and ductile behavior. Van Oort et al. (2022a, 2022b) and Fjær et al. (2023) identify favorable characteristics as low Young’s modulus, low cohesion, low unconfined compressive strength, low friction angle, high porosity, high clay content, significant smectite content, low quartz and carbonate cementation, and low wave velocity.

Borehole Stability in Poorly Consolidated Sediments

A second major geological factor affecting well integrity in the Gulf Coast Basin is the mechanical instability of poorly consolidated sediments, especially in young depositional intervals and under conditions of shallow burial. Deepwater shallow-sediment studies describe materials with weak consolidation, strong plasticity, and behavior closer to saturated soil than to competent rock. Yan et al. (2015) show that such sediments are prone to borehole shrinkage and downhole leakage, and that the drilling window may be narrow because very low fracture pressure can coexist with strong collapse tendencies. In Gulf Coast settings where young, undercompacted siliciclastic sediments are common and where wells have often been drilled through mechanically weak formations before reaching deeper targets.

Yan et al. (2015) also argue that borehole instability in such sediments cannot be understood adequately using purely elastic models. Figure 17 illustrates the elastic–plastic framework used by Yan et al. (2015) to describe shrinkage around a wellbore in poorly consolidated sediments. In their formulation, the near-wellbore region may enter a plastic state without immediate catastrophic collapse, but low mud density can still cause serious borehole shrinkage that interferes with tripping and subsequent cementing operations.

They further show that excess pore pressure generated near the borehole wall can reduce effective stress and contribute to fracture initiation. In practical terms, the problem is not simply whether the borehole remains nominally open during drilling, but whether time-dependent deformation and pore-pressure effects degrade borehole quality sufficiently to compromise later casing and cement placement.

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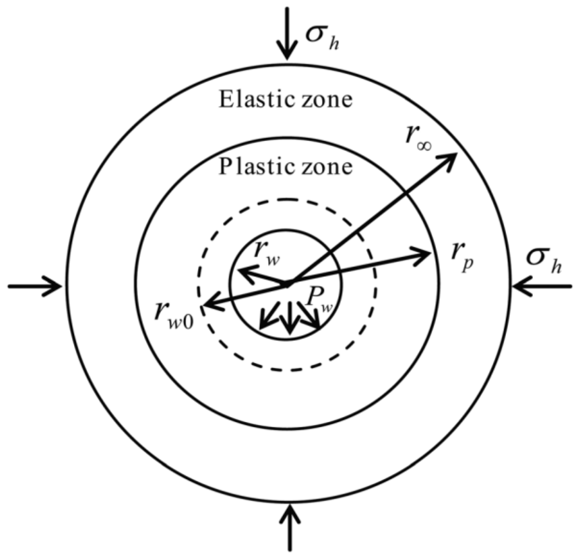

Figure 17. Elastic–plastic mechanical model of borehole shrinkage in poorly consolidated sediments (adapted from Yan et al., 2015).

Shrinkage, local wall failure, and excess pore-pressure effects can distort borehole geometry, destabilize the borehole wall, and make casing placement and annular cementing more difficult. If cement is placed in an irregular or unstable annulus, the resulting cement sheath may be discontinuous or poorly bonded, leaving channels or weak interfaces that persist after completion. Geological instability during drilling can therefore become a long-term integrity issue later in the life of the well, especially where zonal isolation was incomplete from the outset (Yan et al., 2015; Ground Water Protection Council, 2023e).

Potential Natural Sealing Mechanisms

Primary control of borehole and annular flow in wells is achieved through engineering barriers, especially casing, cement, and abandonment plugs. However, some geological and drilling-related processes may supplement these engineered barriers by narrowing open pathways or reducing their transmissivity (J. Daniel Arthur et al., 2011c; Chukwuemeka et al., 2023).

One possible mechanism is mudcake-assisted restriction of flow during and shortly after drilling. Yan et al. (2015) assume that a tight mudcake develops on the borehole wall under undrained drilling conditions and helps limit fluid seepage from the borehole into the formation. Mudcake is not a permanent abandonment barrier, but it shows that permeability reduction can begin during drilling rather than only after casing and cementing. In legacy-well terms, open-hole intervals drilled under overbalanced mud conditions may begin their post-drilling history with a partially sealing borehole lining (Chuanliang et al., 2014c).

A second mechanism is borehole closure or partial blockage caused by plastic deformation, caving, or collapse of weak formations. In poorly consolidated sediments, shrinkage may occur before complete collapse, so open or poorly supported annular spaces do not necessarily remain geometrically unchanged through time. Reduced void space is not the same as a verified hydraulic seal. Nevertheless, progressive narrowing of a pathway may still reduce its transmissivity and change the conditions under which later cementing or abandonment barriers perform (Chuanliang et al., 2014c). In Shale-as-a-Barrier (SAAB) studies, certain plastically deforming shales have been shown to move into uncemented or poorly cemented annular spaces and form pressure-tight barriers behind casing (van Oort et al., 2022a, 2022b; Fjær et al., 2023). Van Oort et al. (2022a) report large-scale laboratory experiments showing that shale can form competent low-permeability annular barriers under downhole stress, pressure, and temperature conditions, and that higher effective stress, higher temperature, and favorable annular fluid chemistry accelerate barrier formation. Alternative mechanisms such as caving and collapse were considered, but the growing body of evidence indicates that creep is the predominant mechanism. Figure 18. illustrates the conceptual shale-creep mechanism by which an initially open annulus may progressively narrow and eventually form a pressure-tight barrier behind casing.

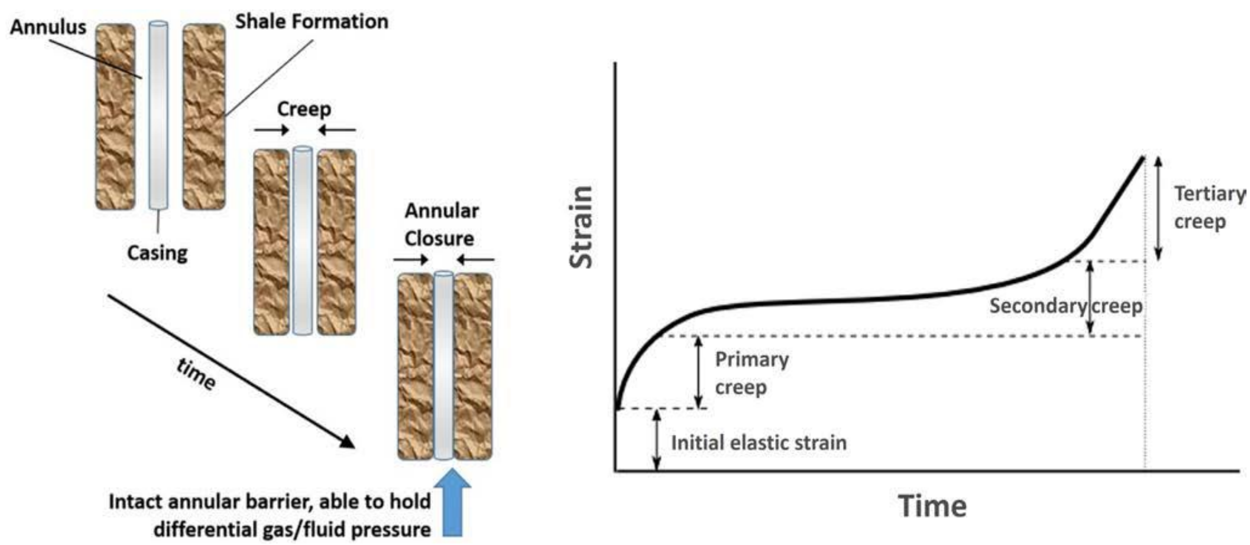

Figure 18. Conceptual shale-creep mechanism for annular closure and barrier formation behind casing (adapted from van Oort et al., 2022a).

Van Oort et al. (2022b) further show that barrier qualification can be based on ultrasonic response together with good casing contact and characteristic shale velocity signatures, while Fjær et al. (2023) distinguish annular closure from true sealing efficiency and show that barrier-forming shales are generally characterized by high porosity, low strength, and favorable ductile behavior rather than high cementation.

Van Oort et al. (2024) show that shale barriers maintained annular pressure integrity during strong cooling and temperature cycling to as low as −14°C, conditions that are potentially damaging to Portland cement because of debonding and micro-annulus formation. Shale barriers are not susceptible to CO_2 chemical attack in the same way as cement because they are formed from caprock material itself. These findings do not prove that all Gulf Coast legacy wells will self-seal, but they do show that creep-driven annular closure is a physically credible mechanism that may reduce or eliminate some flow paths where suitably ductile clay-rich formations are present (van Oort et al., 2024).

The synthesis by Fjær et al. (2023) distinguishes annular closure from true sealing efficiency and shows that the best shale-barrier candidates are generally high-porosity, low-strength materials. Their results identify porosity as a key parameter, while density and P- and S-wave velocities can serve as practical indicators because they correlate strongly with barrier resistance. Their dataset also showed only weak correlations between barrier quality and mineralogical variables such as total clay content and quartz content within the restricted shale population studied. This suggest that, once shales are already clay-rich, petrophysical and mechanical state may be more diagnostic of barrier potential than bulk mineral percentages alone (Fjær et al., 2023).

Thermal-stimulation studies also show that shale creep is sensitive to temperature, but only within limits. Van Oort et al. (2024) report that there is an optimum temperature range for artificial thermal stimulation of shale barriers and that temperatures above about 200–300°C should not be exceeded because irreversible dehydration and metamorphic alteration can damage the shale and reduce its creep and self-healing capacity. This shows that shale sealing behavior is time-dependent and stress-dependent, but also thermally bounded (Van Oort et al., 2024).

CHAPTER III: REVIEW OF LEGACY-WELL RISK CLASSIFICATION APPROACHES FOR CCS

3.1. INTRODUCTION

This chapter reviews published approaches used to classify and screen legacy-well risk in carbon capture and storage studies. It compares how different frameworks define risk, which indicators they emphasize, and how they treat uncertainty related to incomplete records and historical well construction. The purpose is to identify the main strengths and limitations of current classification approaches before evaluating them against empirical evidence.

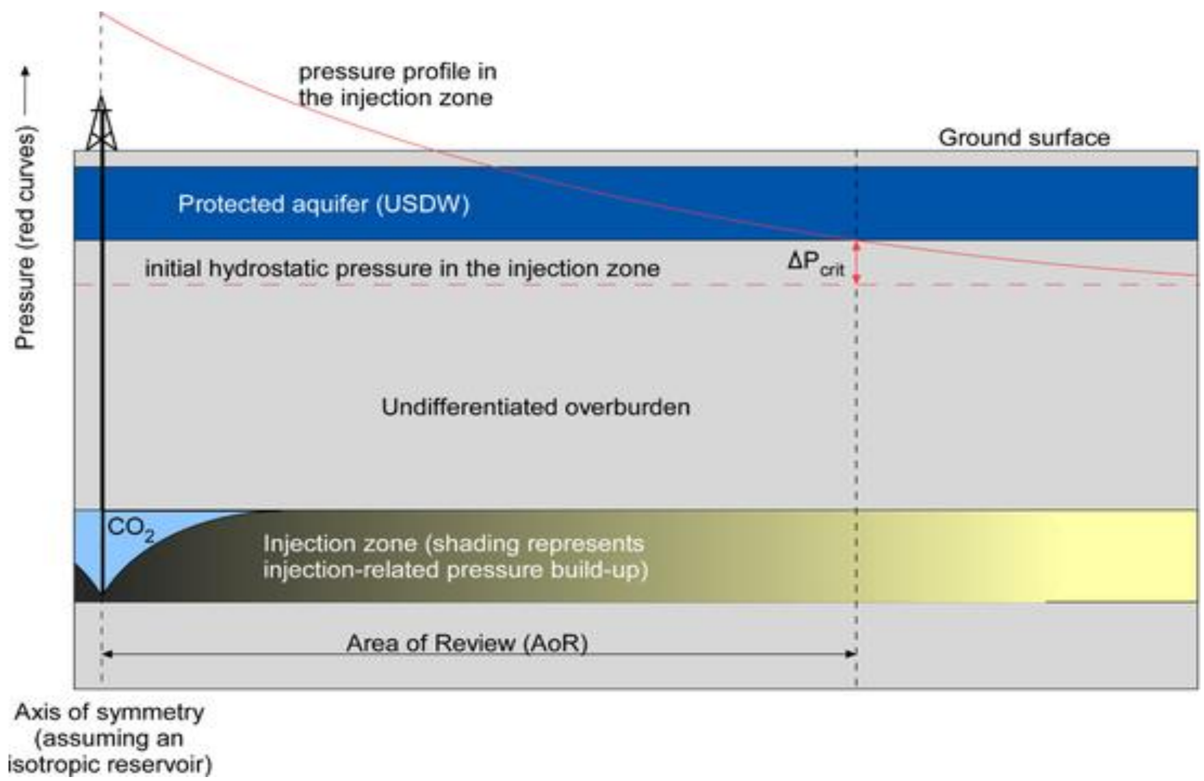

Figure 19. Conceptual relationship between CO_2 plume extent, pressure propagation, and the Area of Review (AoR), illustrating why legacy wells outside the plume but inside the pressure-affected area may still require evaluation (modified after Bump and Hovorka 2023).

Many prospective storage sites are located in mature hydrocarbon basins where the number of existing wells may be extremely large. In such settings, detailed investigation of every well at the earliest stages of project screening is often impractical in terms of time, cost, and data availability. Watson and Bachu (2009) addressed this problem by showing that large well populations can be screened using information commonly available in regulatory databases, including well construction, abandonment, and leakage-related records. Their study of more than 315,000 wells in Alberta demonstrated that wellbore leakage potential can be evaluated at a regional scale and that recurring factors such as low annular cement top, casing failure, external corrosion, and abandonment-related conditions are associated with leakage occurrence (Watson and Bachu 2009).

Risk classification frameworks they help sort large legacy well inventories during early project screening. At this stage, they are used to identify candidate sites where legacy-well risks may be too costly, too uncertain, or too difficult to manage. This helps narrow broad basin-scale well inventories into a more focused, site-specific assessment and can support the selection of a lower-risk site. (Costeño Enriquez et al., 2024; Lackey et al., 2024). After a site is selected, the screening stage is followed by detailed evaluation, and every well within the project area and AoR must then be assessed as part of site characterization, corrective-action planning, and permitting.(U.S. EPA, 2013; Arbad, 2024).

As Bump and Hovorka (2023) emphasize, the size and location of the AoR directly affect the number of legacy penetrations that may need to be evaluated, remediated, or managed, making legacy-well screening a major technical and economic issue for some commercial-scale storage projects.

3.2. EXISTING RISK CLASSIFICATION APPROACHES

Published legacy well risk classification approaches do not all serve the same purpose, even when they are often discussed together in CCS literature. Some were developed primarily to identify wells with relatively high leakage potential from large regulatory databases, some were designed to support corrective-action planning within a Class VI AoR, and others were built to compare candidate storage sites, quantify leakage risk, or rank wells for monitoring. For that reason, the literature is best reviewed as a set of related approaches that differ in objective, required data, and output format. Watson and Bachu (2009) represent the foundational database-driven leakage-screening approach; Arbad (2024) provides a Class VI-oriented qualitative categorization framework; Costeño Enriquez et al. (2024) present a site-selection scoring method; and studies such as Duguid et al. (2017), White et al. (2020), Zulqarnain et al. (2019), Sminchak et al. (2014), Nowamooz et al. (2018), and Ide et al. (2006) broaden the literature by emphasizing monitoring, AoR-based risk, quantitative leakage metrics, regional well-condition screening, basin-specific adaptation, and regulatory context respectively.

Watson and Bachu Well Integrity Framework

Watson and Bachu (2009) developed one of the earliest and most influential methods for assessing the potential for gas and CO_2 leakage along existing wells. The objective of their framework was to determine which wellbore attributes, available from large regulatory databases, are most strongly associated with observed leakage and then use those attributes to build a practical screening method for identifying wells with relatively high leakage potential in areas being considered for CO_2 storage. Their study was based on more than 315,000 oil, gas, and injection wells in Alberta and used recorded occurrences of surface-casing-vent flow (SCVF) and gas migration (GM) as the principal field indicators of leakage behavior. In this sense, the Watson and Bachu framework is fundamentally an empirical screening method: it begins with observed leakage occurrence and works backward to identify the well characteristics most consistently associated with that occurrence.

The key risk indicators in Watson and Bachu (2009) are those well attributes that showed strong or meaningful relationships with SCVF/GM. Their analysis identified major relationships between leakage occurrence and low annular cement top, external corrosion, casing failure, abandonment-related conditions, well type, deviation, regulatory era, economic activity, and geographic location. By contrast, several other variables were found to have minor or no clear effect in their dataset, including well age by itself, operational mode, total depth, surface casing depth, well density, topography, and the presence of H_2S or CO_2. The importance of this paper lies partly in that distinction: it attempted to separate strong predictors from weak ones on the basis of observed data.

The data used in the Watson and Bachu framework were primarily regulatory and industry records rather than field-specific diagnostic tests for every well. This makes the framework especially attractive for regional screening, because it relies on information that may already exist in government or operator databases. Its output is a relative assessment of leakage potential expressed through a decision-tree-style classification. The final product is therefore a practical ranking logic. Wells are screened according to a sequence of questions tied to the most important attributes, and the result is a qualitative indication of higher or lower leakage potential.

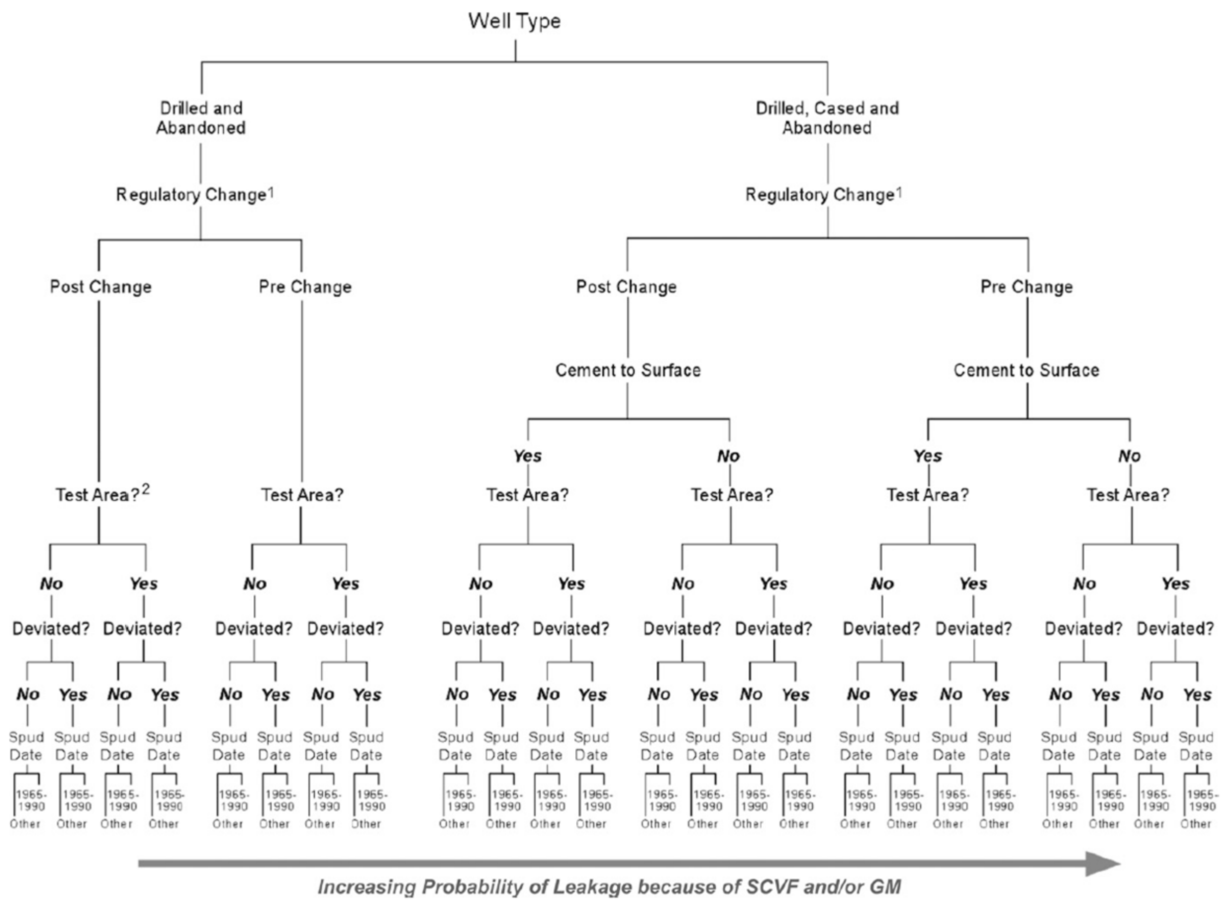

Figure 20. Decision-tree-based screening logic proposed by Watson and Bachu for identifying wells with relatively high leakage potential from publicly available well attributes (adapted from Watson and Bachu 2009).

A major strength of the Watson and Bachu approach is that it links screening directly to field-observed leakage indicators. However, its output remains qualitative, and the framework is focused primarily on the intrinsic characteristics of the well. In other words, it is highly useful for identifying wells that appear more likely to leak in general, but it does not by itself determine whether a given well is actually exposed to project-driven pressure conditions or positioned to act as a migration pathway in a particular CCS setting. That limitation became one of the reasons later frameworks incorporated AoR position, geologic penetration, and corrective-action complexity more explicitly.

Arbad Legacy Well Risk Classification

Arbad (2024), building on Arbad et al. (2022), developed a qualitative risk assessment methodology specifically aimed at legacy wells within the AoR of CCS projects and at the practical needs of Class VI permit applications. The objective of this framework is to organize all wells within the AoR into standardized categories that support tabulation, mapping, and phased corrective-action planning. This gives the Arbad framework a more directly regulatory and project-management-oriented purpose than Watson and Bachu (2009), which was primarily a leakage-potential screening methodology.

The key risk indicators in the Arbad methodology are geologic penetration, the status of reported mechanical barriers, and well accessibility. More specifically, the method classifies wells into nine pre-defined well types based on their construction, geologic penetration, and degree of protection of the confining interval, and then assigns five accessibility levels based on whether the well is dry and abandoned, plugged and abandoned, injection, producing, or observation status. In this system, risk decreases as the well type number increases from Type 1 to Type 9 and as accessibility level increases from 1 to 5. The logic is therefore two-dimensional: one dimension reflects the potential for crossflow or migration based on penetration and barrier condition, and the other reflects the practical complexity and cost of intervention.

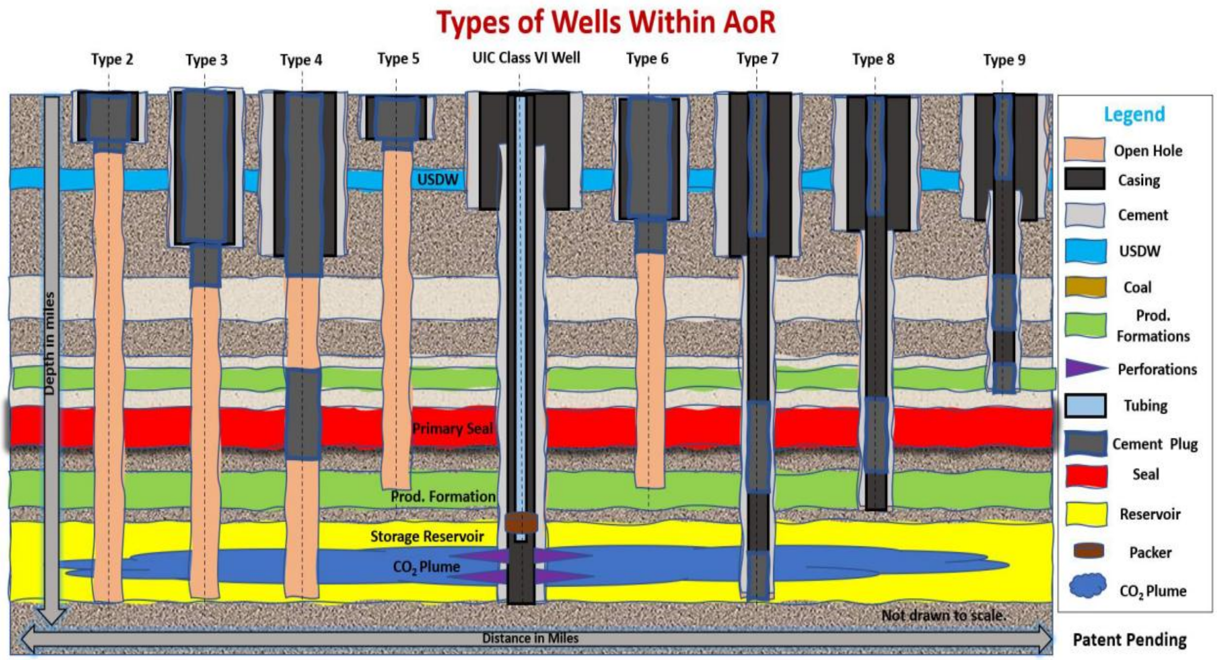

Figure 21. Pre-defined legacy-well categories based on geologic penetration and reported barrier protection, illustrating the qualitative classification logic of the Arbad framework (adapted from Arbad 2024).

Arbad (2024) relies on publicly available well construction details, well reports, well logs, and state-agency records. Compared with Watson and Bachu (2009), the Arbad approach places greater emphasis on project relevance within the AoR and on how the classification can support permit documentation and remediation planning. Its strength is that it integrates geologic penetration, barrier status, and operational accessibility into a single practical workflow. Its limitation is that it remains qualitative and relies heavily on the accuracy and completeness of public records. Nevertheless, among the reviewed studies it is one of the clearest examples of a CCS-specific legacy-well classification system designed for actual Class VI workflows rather than for general discussion of well integrity.

Costeño Enríquez Screening Framework

Costeño Enriquez et al. (2024) developed a legacy-well screening method for potential CO_2 storage sites with the specific objective of comparing candidate locations during early site selection. Unlike Arbad's framework, the Costeño approach is designed to help operators rank alternative storage sites against each other before detailed site development begins. The framework treats legacy-well risk as both a containment issue and a project-viability issue, recognizing that the complexity of corrective action may itself affect whether a site is feasible. The key risk indicators in the Costeño framework are well age, well type, deviation, top of annular cement relative to the seal interval, suspension status, mechanical status, wellhead status, integrity-test history or reported integrity problems, and proximity to public buildings or environmentally sensitive areas. These indicators are grouped more broadly into four aspects of the well: well architecture, well history, well mechanical status, and well location. One of the distinguishing features of this method is that it explicitly includes factors related not only to leakage potential but also to intervention difficulty and surface operational risk. This broadens the meaning of "risk" beyond containment alone.

The data used by Costeño Enriquez et al. (2024) are deliberately limited to information that is quick to obtain during preliminary site screening. This is a high-level screening method by design. Its output is a weighted risk score for each well, a remediation matrix, and a risk-score distribution that allows wells and candidate sites to be compared more consistently. Each criterion is assigned a score from 1 to 5 and a weight from 1 to 3, and the overall well score is then used to build a site-level view of legacy-well risk. The tradeoff is that the weighting system is partly expert-driven and therefore more subjective than a purely data-derived statistical model. Even so, it represents one of the clearest modern examples of a structured storage-site screening workflow that extends beyond simple well-density comparisons.

Other Relevant Risk Classification and Risk Assessment Studies

Beyond the three core frameworks above, several other studies either adapt classification logic to particular basins or expand the concept of risk assessment beyond simple qualitative ranking. Nowamooz et al. (2018), for example, adapted the Watson and Bachu logic to the St. Lawrence Lowlands basin in Quebec. Their objective was to assess the probability of leakage of conventional and unconventional wells in a basin where direct measurement of surface casing vent flow and gas migration was not feasible for all wells. Using drilling reports and abandonment programs for 85 wells, they developed a basin-specific decision tree in which the defining indicators were wellbore deviation, height of cement in casing annuli, abandonment-plug type, and drilling date. The output was a relative probability-of-leakage classification, and their results showed that well deviation and incomplete information on construction or abandonment were especially important in identifying wells with high leakage probability.

Duguid et al. (2017) proposed a well integrity risk assessment for the Weyburn-Midale Field as part of containment-risk monitoring design. The objective of that framework was to rank 1,424 wells in terms of likelihood of CO_2 migration and severity of impact so that monitoring technologies could be deployed more strategically. Their method used 13 categories as proxies for migration likelihood and 4 categories as proxies for severity. The output was a ranked risk profile for both individual wells and risk categories, which was then used to guide monitoring selection.

White et al. (2020) represent a different branch of the literature. Their objective was to evaluate AoR and leakage risks at CO_2 storage sites using the NRAP-IAM-CS toolset. Rather than classifying wells mainly by construction or abandonment status, they used a quantitative, risk-based modeling framework that accounts for the physical and chemical properties of the storage system and legacy wells in order to estimate leakage risks to USDWs. In this approach, key indicators include plume extent, pressure-front extent, well locations, and the permeability distributions assigned to known wells. The data used are therefore more site-model and simulation based than purely record based, and the output is a project risk area or risk-based AoR, together with quantitative estimates of leakage impact. White et al. are thus better understood as an AoR-based quantitative risk-assessment study than as a classic legacy-well classification framework, they they shift emphasis from intrinsic well condition alone to actual project-driven hydraulic relevance.

Zulqarnain et al. (2019) likewise move toward quantitative assessment. Their objective was to estimate field-scale leakage risk associated with wells that intersect a potential CO_2 storage zone in a depleted oil and gas field. They introduced a Well Leakage Index (WLI) for individual wells and a Site Well Leakage Index (SWLI) for the storage site as a whole. Their key indicators include wellbore geometry, well structure class, distance from the injection well, buffer layers between the storage zone and USDWs, and storage-boundary type. The method uses reduced-order models to estimate leakage behavior for cased-cemented, cased-uncemented, and open wellbores, and its output is a quantitative leakage-risk metric that can be mapped across alternative injector locations. This study shows how well-risk screening can be translated into spatially explicit site-planning metrics rather than only categorical rankings.

Sminchak et al. (2014) provide another relevant but somewhat different contribution. Their objective was to summarize wellbore integrity factors in oil- and gas-producing regions of the Midwest United States and to evaluate the corrective actions that would be needed in realistic storage-site study areas. The output is less a formal scoring matrix than a regional and local-scale screening of well conditions and corrective-action needs.

Finally, Ide et al. (2006) objective was to review the technological and regulatory issues associated with leakage through existing wells, especially old, orphaned, and abandoned wells.

Ide et al. (2006) distinguishes broad categories of wells in the United States, including wells not plugged, wells plugged before 1952, and wells plugged after standardized API procedures, and it emphasizes improper cementation, improper plugging, corrosion, overpressure, and related failure modes. The output is therefore a conceptual framework showing why older regulatory era and plugging history matter when thinking about CCS wellbore leakage.

Comparative Framework Matrix for Legacy-Well Risk Approaches in CCS

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Framework	Objective	Key indicators	Data type used	Output type	Main strength	Main limitation
Watson & Bachu (2009)	Regional screening of wells with higher leakage potential	Annular cement top; casing failure/corrosion; abandonment; deviation; regulatory era; location/activity	Regulatory and industry records; construction, abandonment, and SCVF/GM leakage data	Decision-tree qualitative leakage-potential ranking	Grounded in observed leakage behavior across a very large well population	Not project-specific; limited focus on AoR position and hydraulic relevance
Ide et al. (2006)	Conceptual and regulatory framing of leakage through existing wells	Plugging era; improper cementation; improper plugging; overpressure; corrosion; orphan/abandoned status	Conceptual technical and regulatory review	Conceptual risk framing	Clearly explains why vintage and plugging standards matter	Not a formal classification or scoring framework
Sminchak et al. (2014)	Estimate corrective-action burden and screen wellbore conditions in storage study areas	Well status; depth; construction; age; plugging specifications; storage-zone penetration	Regional well records plus local site-study records	Regional/local screening of well conditions and remediation needs	Links screening to practical site-preparation effort	Less formalized than a scoring matrix; no single leakage index
Nowamooz et al. (2018)	Basin-specific leakage-probability classification for Quebec wells	Deviation; annular cement height; plug type; drilling date/regulatory era; well type	Drilling reports and abandonment programs for 85 wells	Decision-tree qualitative probability-of-leakage classes	Adapts Watson–Bachu logic to a specific basin using available records	Qualitative and strongly affected by incomplete historical information
Duguid et al. (2019)	Rank wells for containment-risk monitoring and monitoring design	Top of cement; casing quality/integrity; well type; evaporite casing placement; aquifer protection; proximity to water sources	Existing field and public data for 1,424 wells	Ranked well/category risk profile	Connects risk ranking directly to monitoring strategy	Site-specific and partly expert/proxy based
White et al. (2020)	Risk-based AoR and leakage evaluation tied to USDW impact	Plume extent; pressure front; well locations; permeability assumptions; receptor impact	Site characterization and computational modeling	Quantitative project risk area / risk-based AoR	Emphasizes actual pathway relevance, pressure exposure, and receptor risk	Model-dependent; not a classic well-condition matrix
Zulqarnain et al. (2019)	Estimate field-scale leakage risk and compare injector locations	Wellbore geometry/structure; distance from injector; buffer layers to USDWs; storage boundary; well class	Public well data plus reduced-order leakage models	Well Leakage Index (WLI) and Site WLI	Quantitative and spatially explicit for site planning	Relies on simplified well classes and model assumptions
Costeño Enriquez et al. (2024)	Compare candidate storage sites during early feasibility screening	Well age/status; architecture; deviation; annular cement vs. seal; mechanical and wellhead status; data quality; remediation complexity	Quick-access public/private well records	Weighted well score and site-level screening	Very useful for early site comparison; includes corrective-action complexity	Weights are partly expert-driven and subjective
Arbad (2024)	Classify legacy wells within the AoR for permit	Geologic penetration; barrier/protection status;	Public well reports, logs, and state-agency records	Nine well types plus five accessibility levels	Highly CCS-specific and practical for Class VI	Qualitative and sensitive to record completeness

Table 1. Comparative framework matrix of published legacy-well risk approaches for CCS, comparing framework objective, key indicators, data type used, output type, principal strength, and principal limitation.

3.3. COMPARATIVE EVALUATION OF RISK FACTORS

Although published legacy-well risk frameworks vary in purpose and complexity, they share a common underlying assumption: some well attributes are more informative than others when screening for potential leakage risk in CCS settings. Across the literature, the most frequently recurring indicators are well status, regulatory or plugging vintage, cement quality or annular cement coverage, casing integrity, plugging method, data quality, and some measure of hydraulic or project relevance. These factors recur because they relate either to the physical capacity of a well to act as a vertical conduit or to the practical uncertainty surrounding the actual condition of the well (Watson and Bachu 2009; Ide et al. 2006; Sminchak et al. 2014; Nowamooz et al. 2018; Duguid et al. 2019; White et al. 2020; Zulqarnain et al. 2019; Costeño Enríquez et al. 2024; Arbad 2024).

A first major point of agreement is the importance of well construction quality and barrier condition. Cement coverage, cement quality, casing integrity, and abandonment method are treated as central variables in most studies because they directly control the ability of a well to maintain zonal isolation. Watson and Bachu (2009) found that absence of cement across critical annular intervals was one of the strongest predictors of surface casing vent flow and gas migration, while casing failure and corrosion were also strongly associated with leakage occurrence. Similarly, Nowamooz et al. (2018) retained cement in casing annuli, abandonment-plug type, and well deviation as major variables in their leakage-probability decision tree, and Duguid et al. (2019) used cement top, cement quality, casing quality, and casing failure history as explicit scoring categories in their Weyburn-Midale assessment. Costeño Enríquez et al. (2024) likewise treat annular cement, mechanical condition, and wellhead status as core elements of early screening, while Arbad (2024) organizes risk partly around the degree to which geologic penetrations are protected by reported barriers.

A second recurring factor is well age or regulatory/plugging vintage, although the way this variable is interpreted differs across studies. Ide et al. (2006) emphasize that wells drilled or plugged before modern regulation, and especially before standardized cement formulations and plugging procedures, are more likely to contain inadequate barriers or undocumented materials. Watson and Bachu (2009), however, are more careful: they found that simple well age by itself was not one of the strongest direct predictors of leakage in the Alberta dataset, but that abandonment era and regulatory changes were still meaningful because they reflected changes in testing and cementing practice. Nowamooz et al. (2018) also include drilling date as a decision-tree variable, and Costeño Enríquez et al. (2024) use age as one of several weighted screening parameters. They generally agrees that vintage matters, but more as a proxy for differences in regulation, materials, and construction quality than as an isolated chronological variable.

A third point of commonality is the role of well status and abandonment condition. Whether a well is active, suspended, abandoned, plugged and abandoned, or orphaned is widely treated as relevant because status affects both the likelihood that barriers were installed and maintained properly and the feasibility of intervention if problems are identified. Ide et al. (2006) distinguish unplugged, pre-1952 cement-plugged, and post-1952 plugged wells because these categories imply different expected barrier conditions. Sminchak et al. (2014) likewise analyze regional well populations partly by status and plugging specifications, while Costeño Enríquez et al. (2024) include suspension status and wellhead status in their weighted screening system. Arbad (2024) goes further by integrating accessibility directly into the classification logic, recognizing that some wells may pose greater management concern not only because of intrinsic integrity uncertainty but because they are difficult or costly to re-enter and remediate.

Despite these common factors, the frameworks differ substantially in how risk is conceptualized and weighted. Watson and Bachu (2009) are primarily concerned with identifying construction and abandonment-related variables associated with observed leakage. Their approach is therefore dominated by wellbore-condition indicators. Nowamooz et al. (2018) remain close to that logic, although their basin-specific decision tree places especially strong emphasis on deviation and information completeness. By contrast, White et al. (2020) and Zulqarnain et al. (2019) move away from intrinsic well condition alone and toward hydraulic relevance to injection operations. In White et al. (2020), the key question is not only whether a well is poorly constructed, but whether it lies within a risk-based AoR and intersects zones where plume migration or pressure propagation could create leakage consequences. Zulqarnain et al. (2019) similarly include distance from the injector, storage-boundary conditions, intervening buffer layers, and wellbore type in a quantitative Well Leakage Index. Duguid et al. (2019) occupies an intermediate position: it still evaluates cement, casing, and well age, but also includes plume-zone exposure, aquifer protection, and distances to neighbors, water sources, and environmentally sensitive areas.

Another important difference concerns the treatment of missing information and uncertainty. In several frameworks, incomplete records implicitly increase perceived risk. This is particularly clear in Nowamooz et al. (2018), where wells lacking information on deviation, cementation, or abandonment method are pushed toward higher leakage-probability branches in the decision tree. The authors explicitly note that this can bias the results upward, even though such wells may still deserve priority investigation. Arbad (2024) is also built on the reality that complete modern integrity data are unavailable for many older wells and therefore uses publicly available reports and logs to construct a practical qualitative classification. Costeño Enríquez et al. (2024) similarly incorporates record limitations into a weighted screening logic intended for early site comparison.

The reviewed studies also differ in output type, and this affects how their risk factors should be interpreted. Watson and Bachu (2009) and Nowamooz et al. (2018) generate decision-tree-style qualitative or semi-quantitative leakage-potential classes. Arbad (2024) produces predefined well types and accessibility levels that support mapping and corrective-action planning. Costeño Enríquez et al. (2024) produces weighted well scores intended to compare candidate storage sites. Duguid et al. (2019) calculates total risk from expert-derived likelihood and impact categories, while Zulqarnain et al. (2019) develops quantitative leakage indices and White et al. (2020) applies simulation-based risk estimation within a risk-based AoR framework. Because the outputs differ, the same factor may be used for different reasons. For example, distance to injection may be irrelevant in a purely construction-based database analysis but central in a pressure-footprint or site-planning framework. Accordingly, comparative review should not ask only whether a factor appears in a study, but also what role that factor plays in the logic of the method.

Overall, the literature suggests that the strongest point of agreement lies in the importance of cement, casing, plugging, and documentation, while the strongest point of difference lies in whether risk is defined mainly by intrinsic well condition or by actual pathway relevance under injection-induced conditions. Older and more classic studies tend to emphasize construction quality, abandonment method, and regulatory era, whereas more CCS-specific studies increasingly incorporate AoR position, reservoir penetration, plume or pressure exposure, and corrective-action complexity.

Risk Factor	Watson & Bachu (2009)	Ide et al. (2006)	Sminchak et al. (2017)	Nowamooz et al. (2018)	Duguid et al. (2019)	White et al. (2020)	Zulqarnain et al. (2019)	Costeño Enriques et al (2024)	Arbad (2024, dissertation)
Well status (active / abandoned / orphan)	M	H	M	M	H	N/A	M	H	H
Well age	N/A	N/A	M	M	H	N/A	M	H	N/A
Regulatory / plugging vintage	H	H	M	H	M	N/A	M	H	M
Cement quality / annular cement coverage	H	H	H	H	H	N/A	M	H	M
Casing integrity / corrosion / mechanical failure	M	H	H	M	H	N/A	M	H	M
Plug type & abandonment quality	H	H	H	H	M	N/A	M	M	M
Well deviation / trajectory	H	N/A	N/A	H	M	N/A	N/A	M	N/A
Hydraulic relevance / reservoir and confining - zone penetration	N/A	N/A	H	N/A	H	H	H	H	H
Proximity to CO2 plume / pressure front / AoR	N/A	N/A	N/A	N/A	M	H	H	H	H
Data quality / record completeness	N/A	N/A	M	H	M	N/A	N/A	H	M
Corrective-action complexity / accessibility	N/A	N/A	H	N/A	N/A	N/A	N/A	H	H
Natural sealing potential	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Legend

H = High emphasis / explicitly treated as an important screening or risk
M = Moderate emphasis / secondary, conditional, or implicit consideration
N/A = Not explicitly addressed

Table 2. Comparative matrix of risk factors emphasized in published legacy-well risk classification and risk assessment frameworks for CCS. H = high emphasis / explicitly treated as an important screening or risk variable; M = moderate emphasis / secondary, conditional, or implicit consideration; N/A = not explicitly address.

To further highlight which indicators receive the strongest emphasis across the reviewed studies, Figure 22 presents the factors most frequently assigned medium or high emphasis together in the literature.

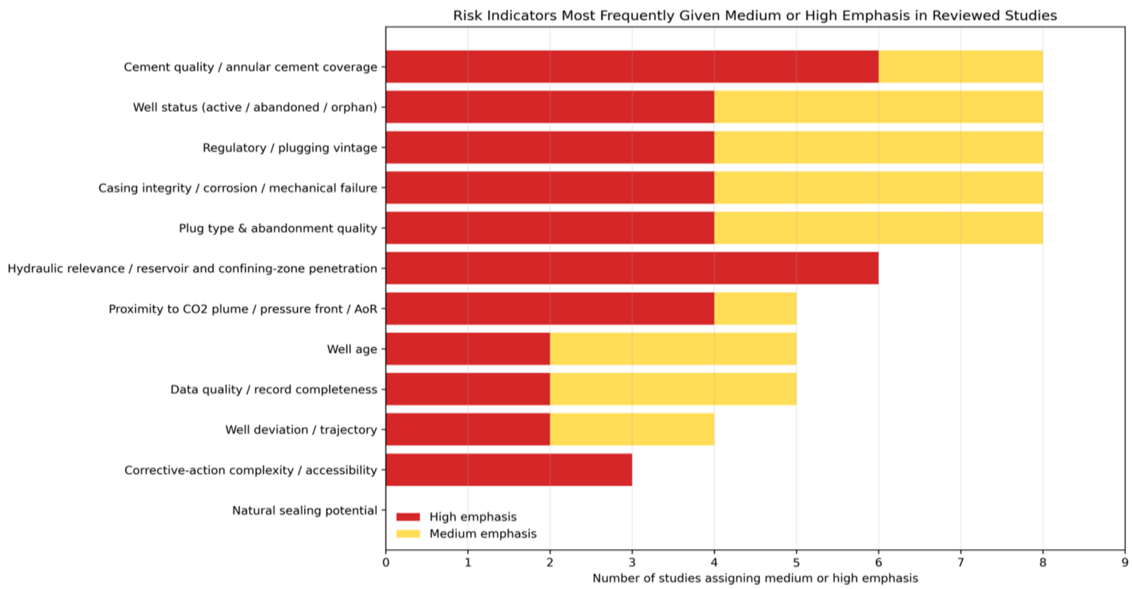

Figure 22. Risk indicators were most frequently assigned medium or high emphasis in the reviewed legacy-well risk studies.

As shown in Figure 22, cement quality and annular cement coverage are the most consistently emphasized indicators across the reviewed studies, followed by well status, regulatory or plugging vintage, casing integrity, plug and abandonment quality, and hydraulic relevance to the storage reservoir and confining system. In contrast, factors such as well age, well deviation, data quality, and corrective-action accessibility appear more selectively, depending on the purpose and structure of the framework. The figure also shows that natural sealing potential is generally not incorporated into existing classification approaches.

3.4. LIMITATIONS OF CURRENT CLASSIFICATION METHODS

Despite their practical value, current legacy-well classification frameworks have important limitations when applied to CCS. Most existing methods are effective as early screening tools, but they do not always distinguish clearly between poor documentation, actual barrier failure, and true project-relevant leakage risk. As a result, many classifications remain precautionary and useful for prioritization, yet still fall short of a fully evidence-based assessment of whether a given well can realistically act as a migration pathway during CO_2 storage operations (Arbad 2024; White et al. 2020; NETL 2016).

A first major limitation is that uncertainty is often treated as failure. Many older wells have incomplete construction files, handwritten reports, missing plugging records, or no modern integrity data such as sustained casing pressure reports, cement bond logs, or detailed cementing records. In practice, frameworks frequently place such wells into higher-risk categories because incomplete information prevents confirmation of adequate zonal isolation. Arbad (2024) states directly that qualitative methods are often preferred when important information is missing or inconsistent, and emphasizes that many older wells lack SCP reports, CBL data, and detailed cementing or casing information. Likewise, Lackey et al (2024) note that non-machine-readable records, incomplete files, and missing construction or plugging information made it difficult to understand the as-built condition of offshore wells, while Nowamooz et al (2018) show that some of the oldest wells in their dataset had no available documentation and were therefore difficult to evaluate except through conservative assumptions.

This conservative treatment is understandable from a regulatory and screening perspective, but it creates an important conceptual problem: uncertainty is not the same as leakage risk. A well with incomplete records may be poorly documented, yet still be hydraulically isolated or physically stable. Conversely, a well with extensive records may still contain an active leakage pathway. When missing information is translated directly into a high-risk classification, the result is often a precautionary ranking rather than a demonstrated leakage assessment. Nowamooz et al. (2018) explicitly caution that flawed construction or abandonment methods do not automatically imply leakage unless the required conditions for leakage are also present, including a source, a driving force, and a pathway. Similarly, White et al. (2020) note that where well integrity data are limited, default permeability distributions may be used in quantitative modeling, which is useful for risk estimation but still reflects uncertainty rather than direct proof of failure.

A second major limitation is the lack of geological context in many classification methods. Several published frameworks focus primarily on well construction and plugging attributes, which are clearly important, but they do not always account fully for the geologic and hydrodynamic setting that determines whether a defect can actually transmit fluids. In CCS, leakage risk depends not only on the condition of cement, casing, or plugs, but also on reservoir pressure buildup, plume extent, pressure-front extent, permeability architecture, confining-zone integrity, fault and fracture behavior, vertical separation from USDWs, and the degree of hydraulic communication between the storage interval and overlying formations. EPA Class VI guidance makes this broader logic explicit by requiring site characterization of geologic, hydrogeologic, geochemical, and geomechanical properties, along with modeling of plume and pressure-front behavior, because site risk cannot be understood from well records alone (US EPA 2013; White et al. 2020).

Poorly constructed well is not necessarily a meaningful CCS leakage pathway unless it is exposed to project-relevant pressure conditions and connects hydraulically to a sensitive receptor. Bump and Hovorka (2023) show that elevated pressure is a key driver of risk and project cost, and that the number of potentially transmissive features requiring evaluation depends strongly on the size and position of the AoR. Lackey et al (2024) similarly note that leakage magnitudes are a function of reservoir conditions at the well location, including pressure, CO_2 saturation, and distance to sensitive receptors. These studies demonstrate that well condition and project setting must be considered together. Frameworks that rely mostly on well construction attributes without fully integrating reservoir pressure, seal properties, and hydraulic relevance therefore risk overgeneralizing well behavior across geologically different settings.

Another, less frequently discussed limitation is that most published classification frameworks are oriented almost entirely toward failure potential and rarely consider whether certain subsurface conditions may reduce transmissivity over time. In clay-rich formations, time-dependent processes such as shale creep, consolidation, swelling, and related sealing or healing mechanisms may in some cases decrease the openness of annular or fracture-like pathways. More broadly, NETL (2016) notes that under some CO_2-storage conditions, leakage pathways in cemented systems may also undergo self-sealing, although this behavior is conditional and depends on fracture aperture, residence time, flow conditions, and geochemical environment. The important point for legacy-well screening is therefore most current frameworks do not evaluate the possibility that some formations or interfaces may evolve toward lower transmissivity over time. As a result, the frameworks are generally conservative and may overstate leakage risk in settings where time-dependent sealing is geologically plausible.

A fourth limitation is the limited calibration of many frameworks against observed leakage data. Some influential studies, especially Watson and Bachu (2009), use reported leakage indicators to identify construction-related variables associated with leakage. However, this evidence comes mainly from oil and gas well experience, particularly natural-gas-related leakage, rather than from direct observation of leakage during CCS operations. Many later CCS screening frameworks are also not calibrated against comparable large-scale failure datasets, partly because relevant data are sparse, inconsistent across jurisdictions, or unavailable for older abandoned wells. Arbad (2024) notes that studies using regional integrity testing data are relatively few and that sustained casing pressure reports were found in only three of 33 U.S. states reviewed in one cited study.

The problem is published frameworks calibration is often incomplete. NETL (2016) reinforces this point by showing that leakage-risk evaluation still depends heavily on laboratory studies, numerical simulation, and reduced-order models.

A related issue is that comparison with injection experience is still limited. CO_2 injection has been practiced for roughly 50 years in enhanced oil recovery, whereas dedicated geologic storage has a much shorter operational history (Loria and Bright, 2021). CCS-specific risk frameworks often discuss legacy wells as potential pathways, but relatively few studies tie their classification logic directly to long-term operational experience, corrective-action outcomes, or historical well failure records under storage conditions. Much of the broader leakage evidence comes from gas leakage in oil and gas wells that differ from those of CO_2 storage (Watson and Bachu, 2009). Lackey et al. (2024) describe their framework as a hazard and corrective-action feasibility assessment rather than a full risk assessment, because a true risk assessment must extend beyond record review to include the broader storage system and field-based characterization. That distinction suggests that many classification approaches are best understood as structured planning tools and may remain highly useful for prioritization and permitting, yet still be largely theoretical in the sense that they are not consistently tested against observed storage-project outcomes.

Another major limitation is the lack of consistency across published legacy-well risk classification frameworks. As shown by the comparative matrix, different studies emphasize different indicators, weighting schemes, and screening priorities, which means that wells may be ranked differently depending on the framework applied.

Figure 23. Conceptual summary of the main limitations of existing legacy-well classification methods.

CHAPTER IV: EMPIRICAL CALIBRATION AND FIELD-BASED EVIDENCE

4.1. INTRODUCTION

This chapter grounds legacy-well risk in evidence. It draws on three main sources: historical incident records, injection-practice and regulatory experience, and literature on natural sealing and long-term barrier evolution. Together, these sources are used to examine how well problems appear in practice, which failures are most relevant to containment, and which pathway types may change through time after drilling, production, and abandonment.

The purpose of this chapter is to sort field observations and published evidence into a form that is useful for risk calibration. In particular, it separates routine operational problems from failures that may matter for long-term containment and considers whether some pathways remain open, partly seal, or evolve in other ways over time. Figure 24 summarizes this progression: first, Class I injection experience is used as a practical reference; second, RRC well-control records are used as empirical failure evidence; and third, these lines of evidence are carried toward field validation. The Orange borehole-closure experiment is introduced later in this chapter as the main field-scale analogue for that final step.

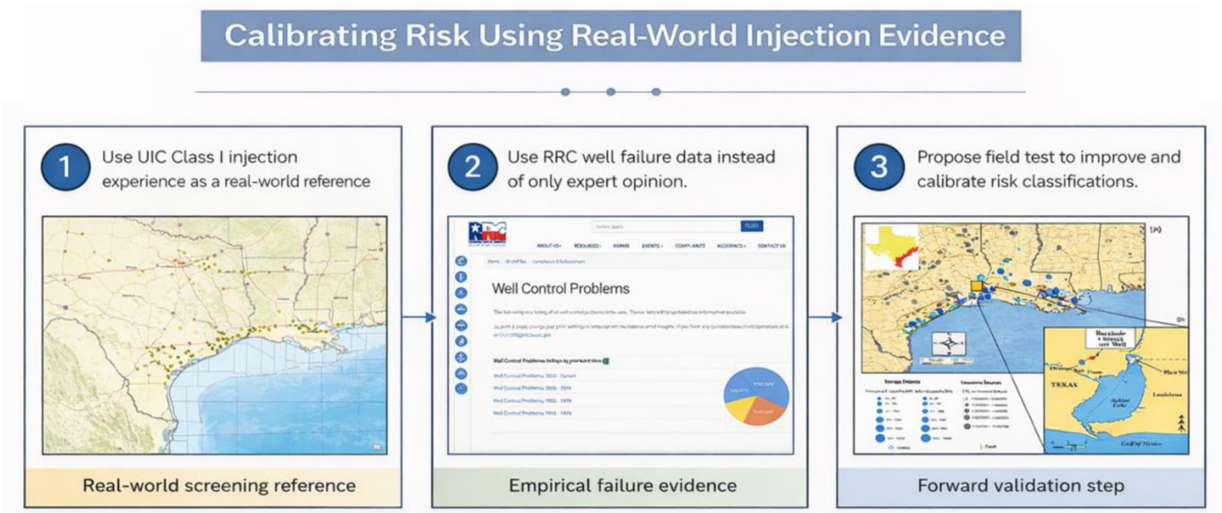

Figure 24. Conceptual workflow used to calibrate legacy-well risk using injection experience, historical failure evidence, and field-based validation.

4.2. HISTORICAL WELL FAILURE EVIDENCE

Historical well failure evidence comes from the RRC Well Control Problems records. The RRC provides these records through its compliance and enforcement webpage as year-based Excel files and searchable incident tables. The agency describes them as listings of well control problems in Texas and notes that the records are updated as information becomes available (Railroad Commission of Texas, 2026).

The records provide a regulatory history of reported field incidents, but they were not assembled as a database of confirmed long-term leakage pathways or barrier failures. The incident tables include fields such as district, date of incident, operator, lease or facility name, lease/ID, API number or permit number, well number, field name, county, fire, H_2S, injuries, deaths, and a remarks field. In many entries, the remarks are short and do not clearly identify the failed barrier, the subsurface pathway, or whether the event is directly relevant to long-term containment.

Porse et al. (2014) encountered the same limitation in an earlier review of Texas RRC blowout records. Their study widened the dataset to include blowouts from all well types because only a few records could be identified definitively as CO_2-related, and they noted that key details were often missing or inconsistently reported. They therefore normalized incident counts to the overall number of wells at different operational stages and found that blowout frequencies were generally small, typically on the order of tenths of a percent or less for a given development stage (Porse et al., 2014).

A total of 1,502 incident records were reviewed in the dataset compiled for this work. Of these, 1,004 did not contain enough information in the remarks to support assignment of a clear reported mechanism. The remaining records were read individually and grouped into categories such as third-party accident, corrosion/aging materials, geologic integrity breach, hydrocarbon leak, offset frac job, small operational failure while drilling, spontaneous brine flow, and unknown. These categories were then separated into broader groups of operational failures, integrity-relevant failures, and unclear/unknown.

Figure 25 shows the workflow used to process the RRC records. The review began with collection of the Texas RRC well control records, followed by separation of entries into records with no clear reported mechanism and records with interpretable remarks. Only the records with interpretable remarks were carried forward into the category-based review. The final step grouped the interpreted records into broader classes for later discussion of CCS relevance.

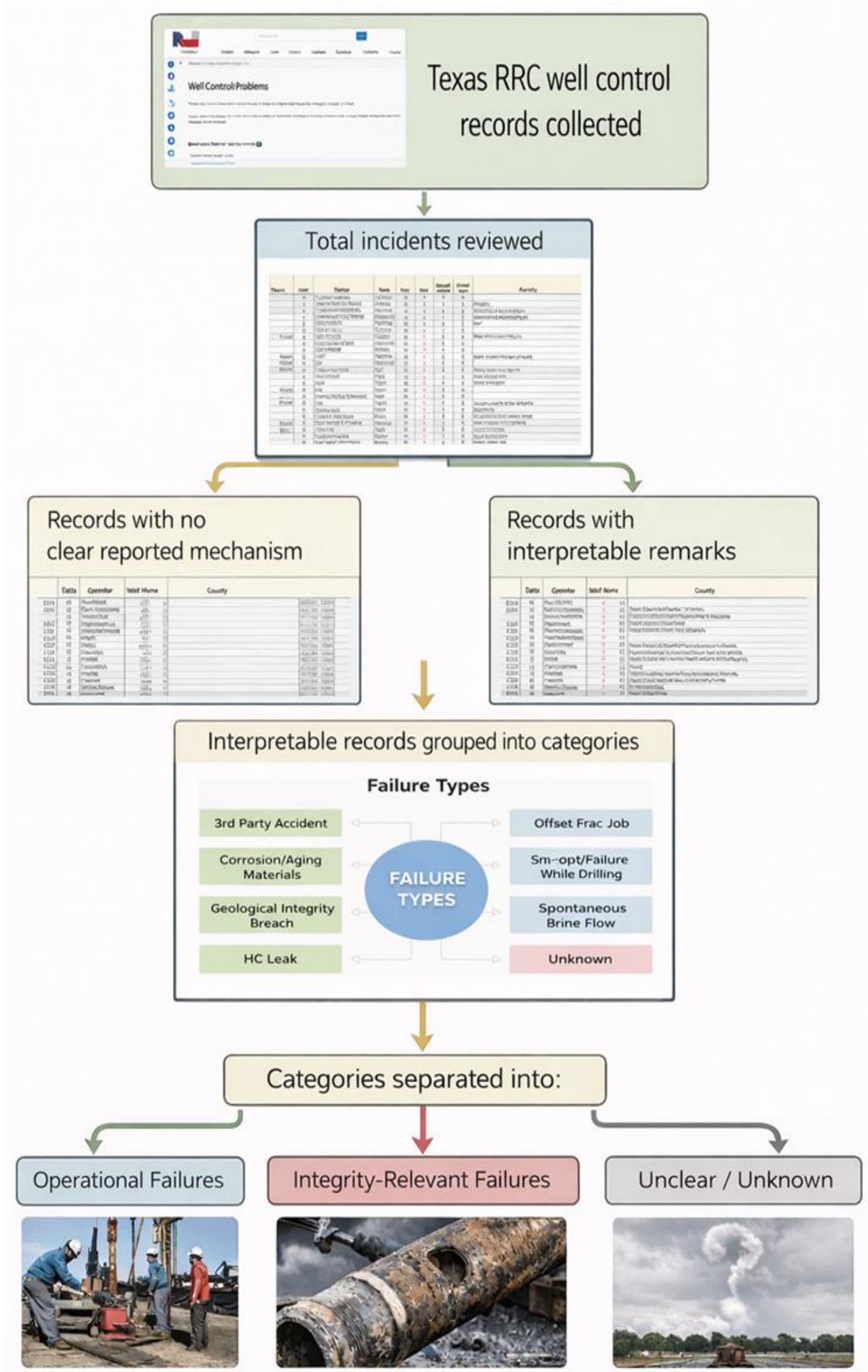

Figure 25. Workflow used to classify Texas Railroad Commission well control incidents into operational, integrity-relevant, and unclear failure categories.

Interpreted category	Description	Typical examples from remarks	Classification group
No failure reported	Record indicates a well control event or complaint, but the remarks do not clearly identify a specific failure mechanism.	Incident response, pressure event, or site visit noted without stating the actual cause or barrier failure.	Unclassified / insufficient detail
Small operational failures while drilling	Short-term operational disturbances associated with drilling, completion, or routine well-control problems, typically not indicating a persistent long-term leakage pathway.	Kick while drilling, mud loss, temporary flow during drilling, operational upset, well-control issue during active operations.	Operational
Hydrocarbon leak	Reported leakage or release of oil or gas that suggests loss of containment through a well component, annulus, tubing, casing, or nearby pathway.	Gas leak, oil leak, annular hydrocarbon flow, surface expression of hydrocarbons, leak at wellhead or casing.	Integrity-relevant
Third-party accident	Incident caused primarily by external human activity rather than by intrinsic well integrity degradation.	Vehicle strike, equipment damage by contractor, line hit, accidental surface damage, external mechanical disturbance.	Operational
Corrosion / aging materials	Failure associated with material degradation over time, including corrosion, mechanical wear, or age-related deterioration of casing, tubing, or well components.	Corroded casing, tubing failure, old equipment failure, material deterioration, aging well hardware.	Integrity-relevant
Offset frac job	Incident linked to pressure communication or disturbance caused by nearby hydraulic fracturing or offset stimulation operations.	Flow or pressure response during nearby frac job, communication from offset well, frac hit, stimulation-related pressure interference.	Operational
Spontaneous brine flow	Unplanned flow of brine or saltwater, usually indicating fluid movement but not necessarily hydrocarbon leakage from a deep storage interval.	Saltwater flow, brine discharge, water flow to surface, spontaneous saline fluid release.	Integrity-relevant
Geologic integrity breach	Incident interpreted as involving failure or compromise of geologic confinement, formation isolation, or unexpected subsurface migration beyond normal operational disturbance.	Flow behind pipe, crossflow between formations, breach of confining interval, migration through geologic pathway, formation communication.	Integrity-relevant
Unknown	Remarks suggest that an incident occurred, but the mechanism is too vague, contradictory, or incomplete to assign confidently to another category.	Ambiguous wording, incomplete remarks, uncertain source of flow, unexplained event with no interpretable mechanism.	Unclear

Table 3. Interpreted failure categories and classification basis.

Table 3 shows how the remarks were translated into a consistent set of categories for later analysis. The "no failure reported" category was used for records in which an incident or complaint was noted, but the remarks did not identify a specific mechanism. "Small operational failures while drilling," "third-party accident," and "offset frac job" were placed in the operational group because these records generally describe short-term disturbances. By contrast, "hydrocarbon leak," "corrosion/aging materials," "spontaneous brine flow," and "geologic integrity breach" were treated as integrity-relevant because they more directly suggest barrier degradation, leakage, or fluid movement outside the intended well system. The "unknown" category was retained for records where an incident was evident, but the remarks were too vague or incomplete to assign confidently to another group.

The interpreted incident record does not describe one single kind of failure. Some entries point to drilling or operational problems, while others are more relevant to well integrity and possible leakage. In a CCS setting, the more important question is whether the event suggests a pathway for fluid or pressure migration outside the storage system. That is why the records were considered by failure type. This follows earlier work showing that leakage depends on the combination of a source, a driving force, and a pathway, and that well construction and abandonment characteristics often say more about risk than the fact that an incident was reported.

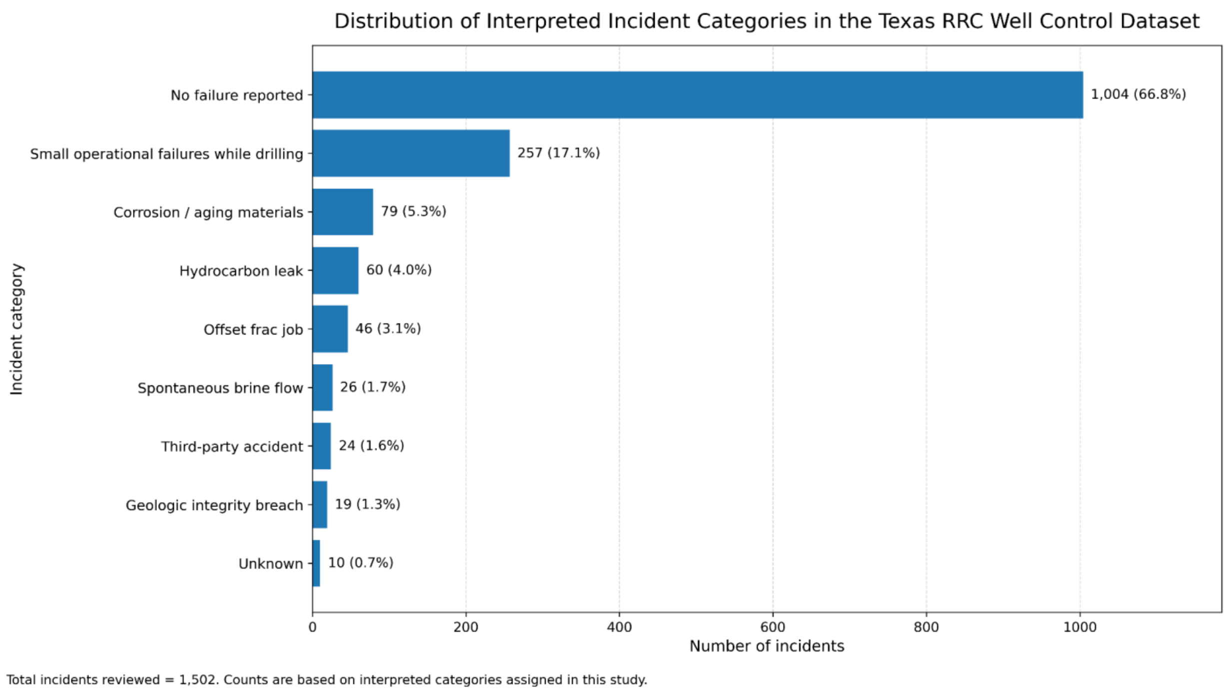

Figure 26. Distribution of incident categories in the Texas well control dataset's.

Figure 26 shows that of the 1,502 incidents reviewed, 1,004 records (66.8%) were placed in the “no failure reported” category because the remarks did not clearly describe the cause of the event. Among the interpretable records, the largest category was small operational failures while drilling, with 257 incidents (17.1%). This was followed by corrosion/aging materials with 79 incidents (5.3%), hydrocarbon leak with 60 incidents (4.0%), and offset frac job with 46 incidents

(3.1%). Smaller categories included spontaneous brine flow with 26 incidents (1.7%), third-party accident with 24 incidents (1.6%), geologic integrity breach with 19 incidents (1.3%), and unknown with 10 incidents (0.7%).

The figure indicates that the incident record is dominated by operational events rather than by clearly documented long-term barrier failure. Drilling-related upsets, frac interference, and third-party accidents may be serious operationally, but they do not necessarily indicate lasting loss of zonal isolation. By contrast, categories such as hydrocarbon leak, spontaneous brine flow, geologic integrity breach, and part of the corrosion/aging materials group are more relevant to CCS screening because they more directly suggest casing damage, cement failure, plugging problems, or fluid movement outside the intended well system. Similar distinctions appear in the well integrity literatures, where leakage risk is linked more strongly to casing failure, low annular cement, abandonment condition, and other pathway-forming features than to incident occurrence by itself (Watson and Bachu, 2009; Sminchak et al., 2017; Lackey et al., 2024).

4.3. INTERPRETATION OF INCIDENT DATA

Regulatory datasets reflect not only actual field problems, but also changes in inspection frequency, reporting practice, and the amount of detail recorded in incident remarks. For that reason, the Texas well-control record is better read as evidence of the kinds of problems that were reported in the field.

One issue is the temporal distribution of the incident record. In the Texas datasets, interpreted incidents are concentrated in the 2000 - 2019 period, with much smaller counts in the earlier 1930 - 1979 and later 2020 - current bins. That pattern might appear to suggest that failures became more common during the modern development period. However, integrity studies have shown that such patterns are not straightforward. Ingraffea et al. (2014) note that inspection-based datasets are temporally dependent: older wells may have incomplete reporting histories, while newer wells have had less time for problems to appear and be documented. Jackson (2014) makes a similar point for Pennsylvania, showing that apparent differences between older and newer wells are shaped not only by performance, but also by exposure time and reporting conditions. In that sense, the concentration of Texas incidents in 2000 - 2019 is more reasonably interpreted as the result of operational intensity, reporting density, and observation window than as direct evidence that wells from that period were inherently more failure-prone (Jackson, 2014; Ingraffea et al., 2014).

A second issue is the difference between a reported field incident and a storage-relevant containment failure. Watson and Bachu (2009) describe leakage along wells in terms of three requirements: a source, a driving force, and a leakage pathway. Even where a source and pressure drive are present, leakage still depends on whether a connected pathway exists along the wellbore. Jackson (2014) likewise notes that many integrity problems are associated with casing and cement defects, but not every such problem leads to sustained migration.

Taken together, the Texas incident data are most useful when interpreted by mechanism and physical relevance. Temporal trends need to be treated cautiously because reporting histories are uneven. Surface leaks, vent flow, and gas migration are important warning signs, but they are not automatically equivalent to deep reservoir-to-surface failure. Operational well-control events may dominate the historical record, yet many of them are only indirectly relevant to long-term storage containment.

4.4. LESSONS FROM CLASS I AND CLASS II INJECTION OPERATIONS

Class I and Class II injection wells show how injection-related risk has been handled in practice under the UIC program. The UIC program governs injection wells, while the Texas Railroad Commission records discussed earlier include a broader set of wells and incidents, including injection wells but not limited to them. The RRC records provide a history of reported field incidents, whereas the UIC framework shows how injection-well risk is defined, screened, tested, and managed under regulatory practice (40 CFR Part 146).

Luciano (2023) argues that Class VI permitting and operation still have a limited empirical record, whereas Class I datasets provide a much longer operational history, including core analyses, well logs, falloff tests, injected volumes, and pressure buildup through time. Class I wastewater injection wells provide field-based information that can help set expectations for Class VI reservoir performance and injectivity.

Under the UIC framework, the main question is containment during injection. The regulations in 40 CFR Part 146 are organized around injection-well construction, area of review, corrective action, mechanical integrity, monitoring, and protection of drinking-water resources. Class I experience matters because they provide a long record of how pressure increase, vertical fluid movement, well integrity, and corrective action have been treated in a mature injection program (40 CFR Part 146).

That contrast is summarized in Figure 27. The figure is a conceptual synthesis developed in this study from the published Class VI legacy-well literature review and from the regulatory and screening logic. The values shown are not measured probabilities and they are not formal regulatory scores. On the left side, they represent the relative emphasis given in the reviewed Class VI legacy-well literatureage. On the right side, they represent the relative screening priority suggested by Class I regulatory practice, where hydraulic relevance, area-of-review position, and conduit potential are screened earlier and more directly.

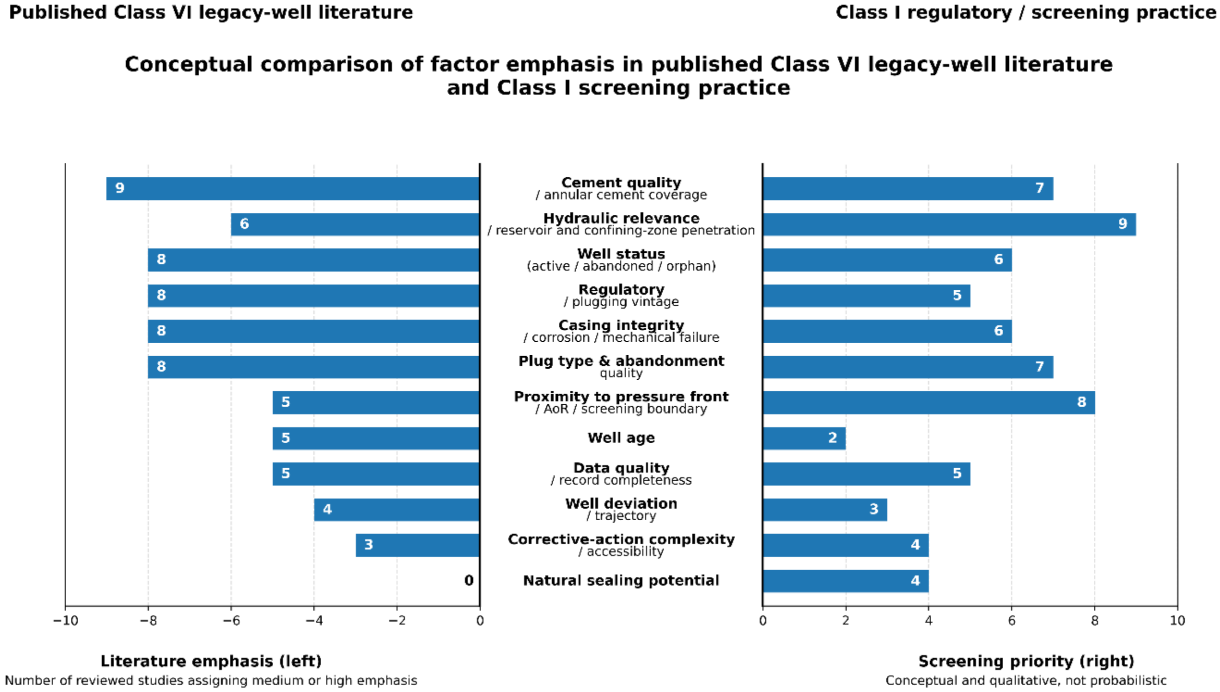

Figure 27. Conceptual comparison of factor emphasis in published Class VI legacy-well literature and Class I screening practice.

Much of the published legacy-well literature gives broad attention to intrinsic well descriptors such as age, status, record completeness, regulatory vintage, casing condition, and cement condition. Class I screening does not ignore those factors, but it tends to filter them earlier through injection-specific questions: whether the well lies within the pressure-relevant system, whether it intersects the relevant reservoir or confining interval, and whether it can plausibly serve as a conduit under injection conditions.

Under 40 CFR Part 146, the area of review is tied to an injection well according to regulatory criteria, and corrective action is tied to wells within that reviewed area. EPA's Class VI guidance extends the same general logic by requiring computational delineation of the area of review, identification of artificial penetrations within it, and evaluation of whether those penetrations could act as conduits for fluid movement. Nicot et al. (2009) make a similar point in the CCS context by showing that the pressure perturbation from geologic carbon storage can extend much farther than the CO_2 plume itself, so review boundaries should be tied to upward-flow potential (40 CFR Part 146; U.S. EPA, 2013; Nicot et al., 2009). This is why Class I and Class VI logic both point toward physical relevance: a well becomes important when it is positioned within the pressure-affected system and has the capacity to transmit pressure or fluids vertically.

Mechanical integrity testing is not limited to UIC-regulated injection wells. In Texas, well-integrity requirements also apply more broadly under state oil and gas rules. The relevance of Class I and Class II practice is that these injection wells are monitored within a formal regulatory framework that makes repeated integrity demonstration especially visible and well documented. Under 40 CFR 146.8, a well has mechanical integrity if there is no significant leak in the tubing, casing, or packer and no significant fluid movement into an USDW through vertical channels adjacent to the wellbore. EPA Guidance No. 39 repeats that standard and explains Part I internal mechanical integrity in practical terms through annulus pressure testing. The broader point is straightforward: injection-well integrity is not assumed from original construction alone. It is demonstrated through testing during the life of the well (40 CFR Part 146; EPA Guidance No. 39).

Guidance No. 39 states that if annulus pressure changes by 10 percent or more during the 30-minute test, the well has failed to demonstrate mechanical integrity. The same guidance also lays out testing intervals for injection wells, including annual testing for Class I hazardous wells and at least every five years for Class II wells with tubing, casing, and packer, with additional testing after certain workovers or temporary abandonment conditions (EPA Guidance No. 39). The practical lesson is that injection-well risk is evaluated through repeated demonstration.

Luciano's Gulf Coast thesis strengthens this point because it shows what a mature injection dataset can provide. The author's Class I analysis uses falloff tests, injectivity calculations, pressure histories, and long-term operational records to evaluate how injection zones actually behave under industrial use. That kind of field record is still limited for Class VI. The value of Class I is therefore not just regulatory language. It is that Class I wells offer measured pressure response, injectivity behavior, and operating history that can be used to ground screening and interpretation in field performance (Luciano, 2023).

Taken together, Class I and Class II experience provide a more useful reference for CCS than a framework built only from generalized well descriptors. The main lesson is decades of regulated injection practice show a consistent pattern: relevant wells are identified through area-of-review logic, conduit potential is screened physically, integrity is tested repeatedly, and corrective action is applied where needed. That operational history is one of the strongest reasons to use Class I and Class II practice as a calibration reference when thinking about legacy-well risk in CO_2 storage, especially in Gulf Coast settings where pressure communication and vertical penetrations through multiple stratigraphic units are central concerns (Luciano, 2023; 40 CFR Part 146; U.S. EPA, 2013).

4.5. NATURAL SEALING AND LONG-TERM BARRIER EVOLUTION IN THE GULF COAST

Natural sealing is relevant to Gulf Coast legacy-well evaluation because some wellbore pathways may become less transmissive with time. The issue is whether pathways created during drilling, completion, production, and abandonment remain open indefinitely after operations cease. In Gulf Coast settings, transmissivity may decrease through mudcake persistence, time-dependent deformation of weak clay-rich sediments, closure of small shale-bounded apertures, clamping of annular defects by creeping formations, and chemical or mechanical evolution at cement-bearing interfaces. At the same time, the broader well-integrity literature shows that degradation can also occur across the full well system, including casing, plugs, cement, and interfaces. Natural sealing should therefore be treated as a modifying process that may affect pathway persistence in some geometries (Loizzo et al., 2017; Carroll et al., 2016; Fisher et al., 2023; Ibukun et al., 2024).

Pathway types relevant to natural sealing

Natural sealing is not equally relevant to all leakage geometries. It is most applicable where transmissivity is controlled by the surrounding formation or by a stress-sensitive interface. This includes mud-drilled open-hole intervals, uncased exploration penetrations, casing-cement microannuli, cement-formation interfaces, and uncemented annular segments adjacent to creeping shale. It is much less convincing as an explanation for large engineered pathways such as severe casing corrosion, major internal casing voids, or failed and missing plugs. Those pathways may remain important even if smaller interface-scale defects partly self-modify through time.

Weak clastic systems add another complication. Peng et al. (2007) document field-observed casing failures in unconsolidated sandstones and show that damage concentrated in the unconsolidated production interval, especially where sanding-induced cavities removed lateral support from the casing. In their Gudao case study, casing buckling and fracturing accounted for 73.1% of the observed casing damage. This is important here because weak formations do not always reduce transmissivity by gradual closure. Under some conditions they instead promote larger mechanical pathways through casing deformation and failure. For that reason, natural sealing relevance depends on the size, location, and type of pathway being considered (Carroll et al., 2016; Ibukun et al., 2024; Zonetti et al., 2023; Peng et al., 2007).

Shale creep and time-dependent aperture reduction

Shale creep is especially important because it is directly supported by laboratory work on Gulf of Mexico shale. Chang and Zoback (2010) show that compaction of room-dried unconsolidated Gulf of Mexico shale is a permanent, irrecoverable process associated with viscoplastic deformation. In their hydrostatic loading experiments, pressure was increased in 5 MPa steps from 10 to 50 MPa and held constant for 6 h at each step. The shale showed pronounced creep at all elevated stress levels, and creep strain followed a logarithmic function of time. Over a 6 h holding interval, the creep contribution was reported to be as much as about six times the corresponding instantaneous strain. The experiments also showed porosity loss, increases in dynamic moduli, and little recovery during unloading, indicating that the deformation was largely permanent.

Chang and Zoback (2010) further described this behavior using Perzyna viscoplasticity combined with a modified Cam-clay yield model. By fitting creep-strain data, they concluded that hydrostatic yield stress increases by about 6–7% for each order-of-magnitude increase in strain rate. Laboratory-based estimates of yield stress and porosity evolution may be overestimated if field strain-rate effects are ignored. More importantly, study shows that weak Gulf of Mexico shale adjacent to an opening is not mechanically static after drilling. Instead, it may continue to compact and deform with time, which provides a mechanism by which shale-bounded apertures may narrow.

More recent constitutive work supports the broader interpretation that shale creep is often viscoplastic and capable of reducing conductivity in stress-sensitive openings. Li et al. (2024) note that much shale creep is unrecoverable and use a Perzyna-type elasto-viscoplastic formulation to describe creep behavior. In triaxial experiments on Ordos Basin shale at 110°C, they showed that increasing differential stress accelerated the transition from primary to steady-state creep and that time-dependent deformation reduced fracture width in their conductivity simulations. In one simulated case, creep-related closure accounted for 32.07% of the total fracture-width decrease after 72 h. This is not direct evidence for Gulf Coast legacy-well self-sealing, but it supports the mechanical conclusion that creep can materially reduce aperture and conductivity over time where the pathway is stress-sensitive.

Additional support for time-dependent deformation in weak Gulf of Mexico sediments comes from borehole imaging work in the Mississippi fan. Moore et al. (2011) describe borehole failure in very young, clay-rich Gulf of Mexico sediments with 40%–50% porosity and abundant expansive smectite-illite clays. In resistivity images from IODP Site U1322, they identify both conventional low-resistivity breakouts and previously unrecognized high-resistivity features that they interpret as extrusion of soft sediment into the borehole. They refer to this incipient failure mode as “breakins,” distinguishing it from breakouts where material has already spalled away. Their interpretation shows that, in soft, plastic Gulf of Mexico mud-rich sediments, borehole failure does not always begin as outward loss of material. It can also involve inward bulging or extrusion into the borehole, which is conceptually consistent with the idea that some shale-bounded openings may narrow before they fully fail by spalling.

This mechanism is most relevant where leakage depends on a small shale-bounded opening remaining mechanically open, such as an uncased shale interval or a narrow defect adjacent to a weak mudstone. It is less useful for explaining large internal casing voids or missing plugs. From a decommissioning perspective, that interpretation is consistent with shale-as-a-barrier work that treats shale performance as something that must be qualified rather than assumed automatically (Chang and Zoback, 2010; Li et al., 2024; Moore et al., 2011; Fedorova, 2021).

Creeping formations as annular geological barriers

A related but distinct mechanism concerns annular closure and clamping at well interfaces. Here the issue is whether a creeping formation can reduce debonding, close a microannulus, or restore compressive normal stress at the casing-cement-formation interface. Loizzo et al. (2017) argue that creeping formations such as halides, mudstones, and shales can contribute directly to well integrity. They state that such formations can seal uncemented annular sections and large defects in the cement sheath, and that the radial stress they exert can reduce debonding and help restore integrity after a microannulus has formed. Importantly, they frame this as an engineering problem that depends on four types of information: the ultimate radial stress exerted by the formation, the mechanical properties needed to estimate leakage if closure stress is exceeded, the time scale required for defect closure, and the type and extent of geochemical reactions between the formation and the leaking fluid.

Loizzo et al. (2017) support this interpretation with field-based examples showing that creeping formations may contribute to annular resealing under some conditions. Their discussion includes both the Orange County borehole-closure experiment in Texas and annular-bond recovery evidence from the Paris Basin, indicating that interface behavior can evolve through time toward reduced leakage in some creeping-shale settings.

This interpretation is strengthened, but also limited, by the broader shale-barrier review of Fisher et al. (2023). That paper shows that faulted and fractured shales have acted as seals to petroleum reservoirs and abnormally pressured compartments over geological timescales, implying that shale-related leakage paths may either form without becoming long-lived conduits or may act as temporary conduits and later reseal. High overpressures can suppress self-sealing and allow flow through weak shales. In other words, creeping formations can contribute to annular integrity, but their performance cannot be treated as independent of pressure history. Fedorova (2021) reaches a similar methodological conclusion from the decommissioning perspective by treating shale-as-a-barrier as a barrier candidate that requires qualification by test protocol, barrier extent, and long-term assessment (Loizzo et al., 2017; Fisher et al., 2023; Fedorova, 2021).

Cement, casing, and interface evolution under CO2-rich conditions

Cement, casing, and interface evolution under CO_2-rich conditions can either reduce or increase leakage potential, depending on the initial defect geometry, flow conditions, chemical environment, and stress state. The intact cement exposed mainly to diffusion-limited CO_2-rich brine may alter relatively slowly, whereas pre-existing pathways such as fractures, channels, and microannuli can evolve in different directions depending on transport and reaction conditions. Some studies report permeability reduction through carbonate precipitation, clogging, or stress-assisted closure, while others show permeability increase or mechanical weakening where defects are larger or flow-through alteration is more sustained (Carroll et al., 2016; Carey et al., 2010; Jahanbakhsh et al., 2021).

Reviews of CO_2 well integrity and plugging systems show that leakage risk does not depend only on the cement plug itself, but on the condition of the entire barrier system. Although some experiments suggest that corrosion rates may decline under stagnant conditions because protective corrosion products form, this should not be assumed for all legacy-well environments. In wells with poor initial cementing, shrinkage-related defects, damaged interfaces, or persistent fluid movement, behind-casing leakage and corrosion remain credible long-term concerns. Natural sealing may occur in some settings, but it cannot be assumed to overcome all legacy-well barrier defects, especially where poor cement placement, shrinkage, corrosion, or pre-existing leakage pathways already exist (Azuma et al., 2013; Chukwuemeka et al., 2023; Dusseault et al., 2000; Rasool et al., 2025).

What natural sealing does not solve

Natural sealing does not remove the need to evaluate larger engineered pathways directly. The literature reviewed above is most relevant to small apertures, stress-sensitive pathways, shale-bounded openings, and some interface-scale defects. It is much less convincing as an explanation for large internal casing voids, severely corroded casing strings, poorly placed or missing plugs, or uncased exploration penetrations that connect multiple intervals.

The broader well-integrity literature shows why this distinction matters. Ibukun et al. (2024) identify casing and cement degradation, gas migration, corrosion, cracks, leaks, and micro-annuli as major contributors to sustained casing pressure and well-integrity failure, treating these as full barrier-system. Chukwuemeka et al. (2023) likewise argue that long-term leakage paths may still develop in old casing and cement left below permanent plugs, even when the plug itself is properly placed, because exposed wellbore materials can continue to interact with reservoir fluids after abandonment.

Field and modeling evidence from unconsolidated formations further reinforces this limit. Peng et al. (2007) show that in weak sandstones, sanding-induced cavities can remove lateral support from the casing, causing much larger casing deformation, buckling, and even shear failure. Their study reports that casing failures in the Gudao reservoir were concentrated in unconsolidated sandstone intervals and were strongly associated with cavity development around the casing. It shows that weak formations do not always reduce transmissivity by gradual closure. Under some conditions they instead promote larger mechanical failures that natural sealing cannot be relied upon to offset.

Pressure limits and relevance to Gulf Coast CCS

Self-sealing processes may help reduce transmissivity in some defects, but they do not eliminate leakage risk where pressure is sustained and barrier failure remains active. Studies of shale sealing and well integrity show that closure behavior depends on whether pressure drive declines enough for narrowing or clogging processes to persist, rather than being continually opposed by fluid pressure and buoyancy. (Fisher et al., 2023; Ibukun et al., 2024; Iyer et al., 2022).

4.6. THE ORANGE BOREHOLE-CLOSURE TEST

Purpose and conservative design basis

The Orange borehole-closure test reported by Clark et al. (2005) was conducted near Orange field, Texas, as part of a no-migration demonstration prepared in response to EPA concern that injected fluids could eventually encounter unidentified abandoned penetrations near the Orange salt dome. The purpose of the test was to determine whether a worst-case abandoned penetration in Gulf Coast sediments would remain hydraulically open or become naturally isolated across a shale interval under imposed pressure conditions. The test therefore addressed the possibility of upward migration through an open-borehole analogue.

The design basis was intentionally conservative. DuPont defined the test around a thin injection sand overlain by a thick, sand-free shale, an open borehole enlarged to 11 in., a mud program consistent with early field practice, and testing with 9.0–9.1 lb/gal brine as a worst-case fluid condition for an abandoned penetration without dependable plugging records. Natural borehole closure would be accepted only if two independent observations agreed: first, water-flow or oxygen-activation logging above the sand showed no upward channeling, and second, the upper transducer showed no pressure buildup during lower-zone pressurization. This paired standard is what made the Orange result a field demonstration.

Figure 28 shows the location of the borehole-closure test well between the Orange salt dome and the plant site. The well was positioned about 5 miles east of the dome and within the potential path of the modeled long-term plume, so the test directly addressed the concern that migrating fluids could intersect an unidentified abandoned penetration in that area.

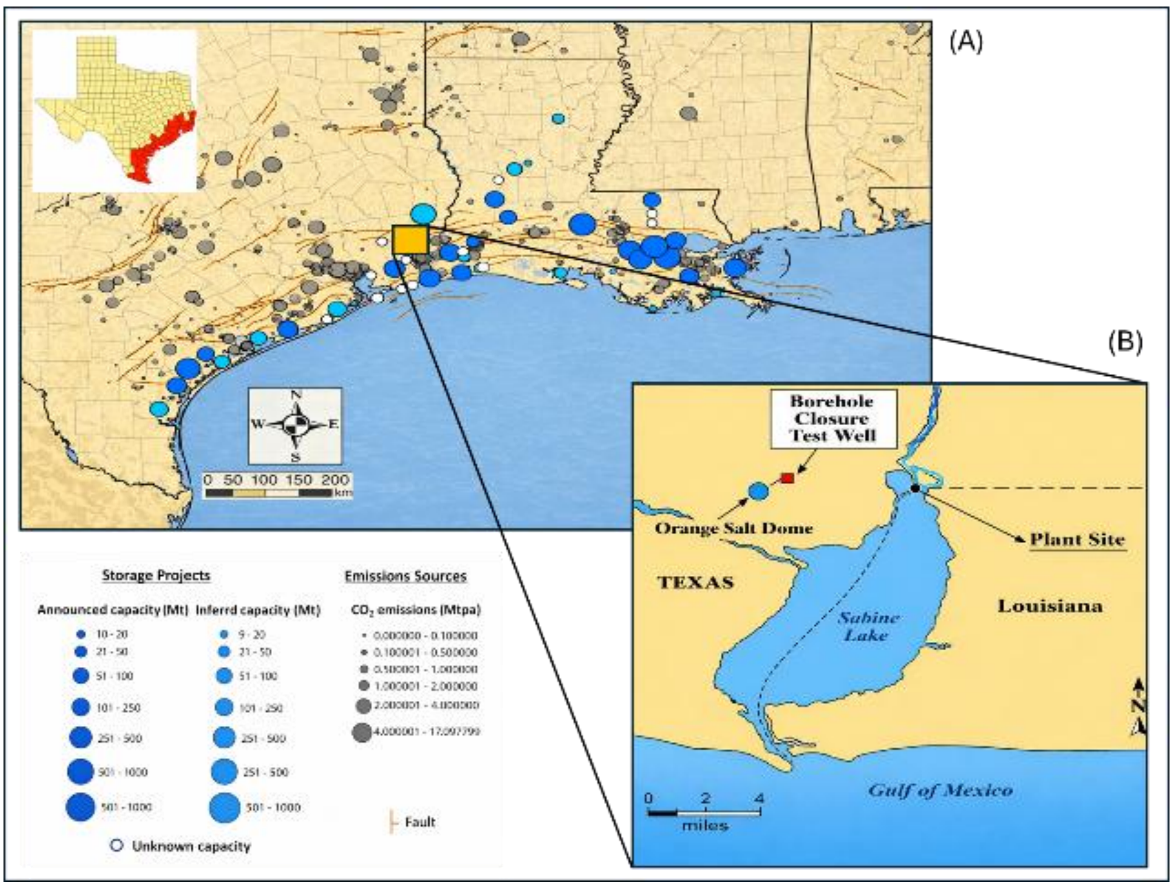

Figure 28. Location of the Orange borehole-closure test well relative to the Orange salt dome and plant site (modified after Clark et al. (2005))

Test interval selection and completion geometry

The selected test interval consisted of 36 net ft of clean sand from 2926 to 2962 ft, overlain by 88 net ft of clean shale from 2838 to 2926 ft. This interval was chosen because the lower sand could accept pressure and provide a clear hydraulic response, whereas the thicker shale above provided the section across which isolation had to be demonstrated. Sidewall core and log data showed sand porosity of about 29.6–31.8% and permeability of about 900–1400 mD, while X-ray diffraction indicated that the shale contained more than 80% expandable smectite clays. The shale overlying the test sand was also verified as continuous and correlatable across the highest point of the Orange salt dome, which strengthened the suitability of the site for the experiment.

The well geometry is critical to understanding the test result. The upper part of the well was cased, but the tested section below the casing shoe was open hole. The well was drilled to 5024 ft, two cement plugs were set below the selected interval, and the borehole across the test section was underreamed to 11 in. A 7 in. casing was set above the interval, while the open-hole section extended downward through the shale and into the upper part of the sand. A screen assembly was then placed across the lower sand so that the lower interval could be pressurized while the upper monitored section could be observed separately. The experiment therefore tested closure of an open borehole through shale, not deformation around a cased interval.

Figure 29 presents the original Orange test interval and completion geometry. The figure distinguishes the cased section from the underreamed open-hole interval and identifies the positions of the upper transducer, lower transducer, screen, casing shoe, top of sand, and base of sand. It shows that the key hydraulic question was whether the shale across the open-hole interval would narrow and isolate the lower zone from the upper monitored section.

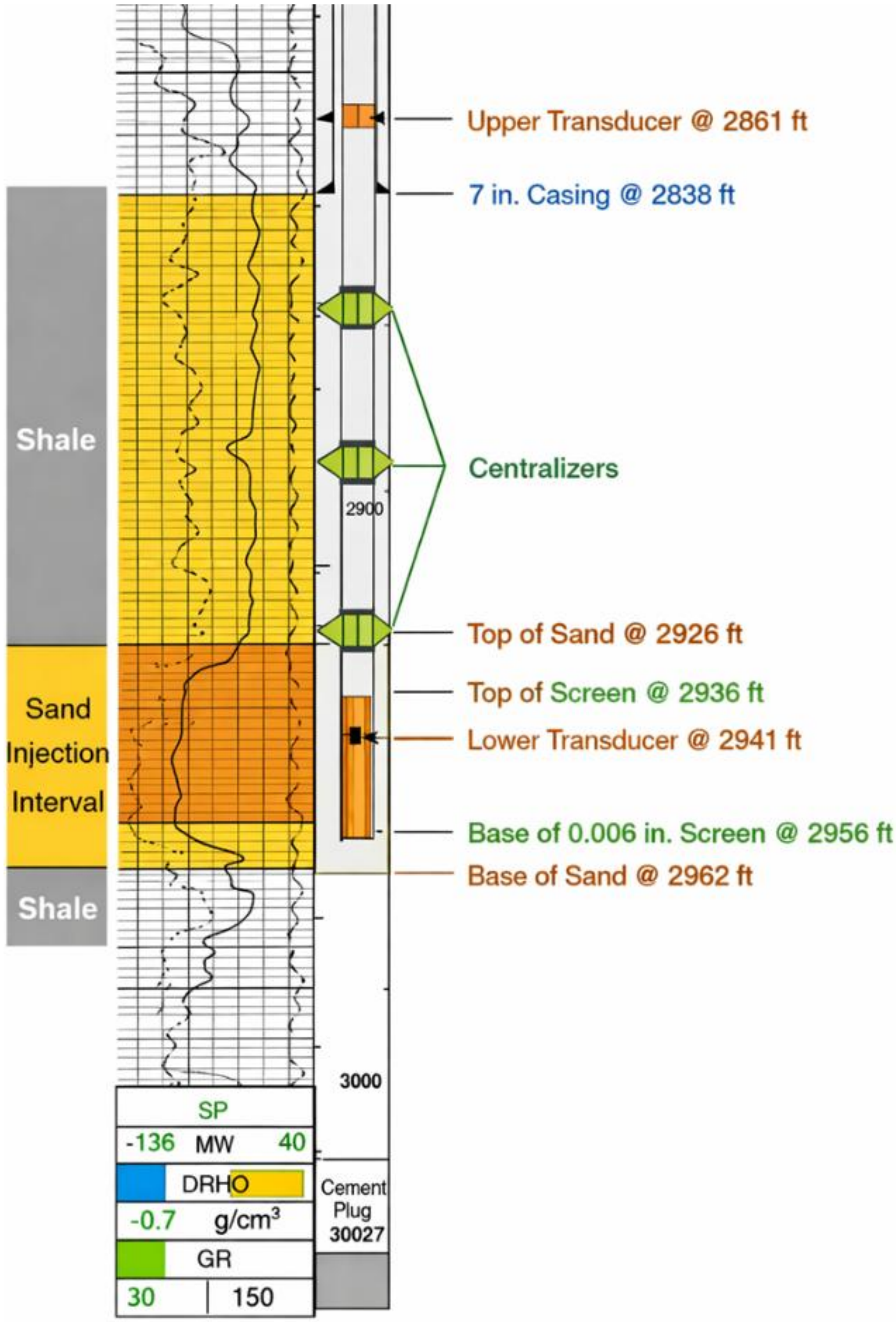

Figure 29. Original Orange test interval and completion geometry, showing the cased section, open-hole underreamed interval, screen, and transducer locations.

Hole preparation, fluid replacement, and instrumentation

After drilling, the open-hole section was conditioned with 9.7 lb/gal mud. The drill string was then pulled into the casing, and the drilling mud was displaced with a fresh-water buffer followed by 9.1 lb/gal filtered brine. A total of 401 bbl of filtered brine was pumped through the injection tubing with returns to the surface. This established the intended test fluid condition and limited mud invasion of the screen assembly.

The instrumentation was checked before the main test began. The lower transducer was positioned inside the screen, approximately 5 ft from the top of the screen openings, and the upper transducer was attached outside the 2 7/8 in. tubing about 120 ft above the lower transducer. During temporary placement near the casing shoe, the lower transducer at 2758 ft recorded 1305 psi and the upper transducer at 2638 ft recorded 1248 psi, both matching hydrostatic expectation for 9.1 lb/gal brine. A dynamic pretest further showed that friction loss in the screen assembly would be less than about 12 psi at 2 bbl/min, while the borehole-closure test itself was conducted at much lower flow rates. These checks showed that the later pressure separation could not be attributed to faulty instrumentation.

Figure 30 shows the well condition after mud displacement and shut-in. It identifies the brine-filled tubing and casing, the transducer positions, the open-hole underreamed section, the shale interval, the injection sand, and the closure area that developed around the tubing assembly. At this stage, the figure links the completion geometry to the pressure data discussed next.

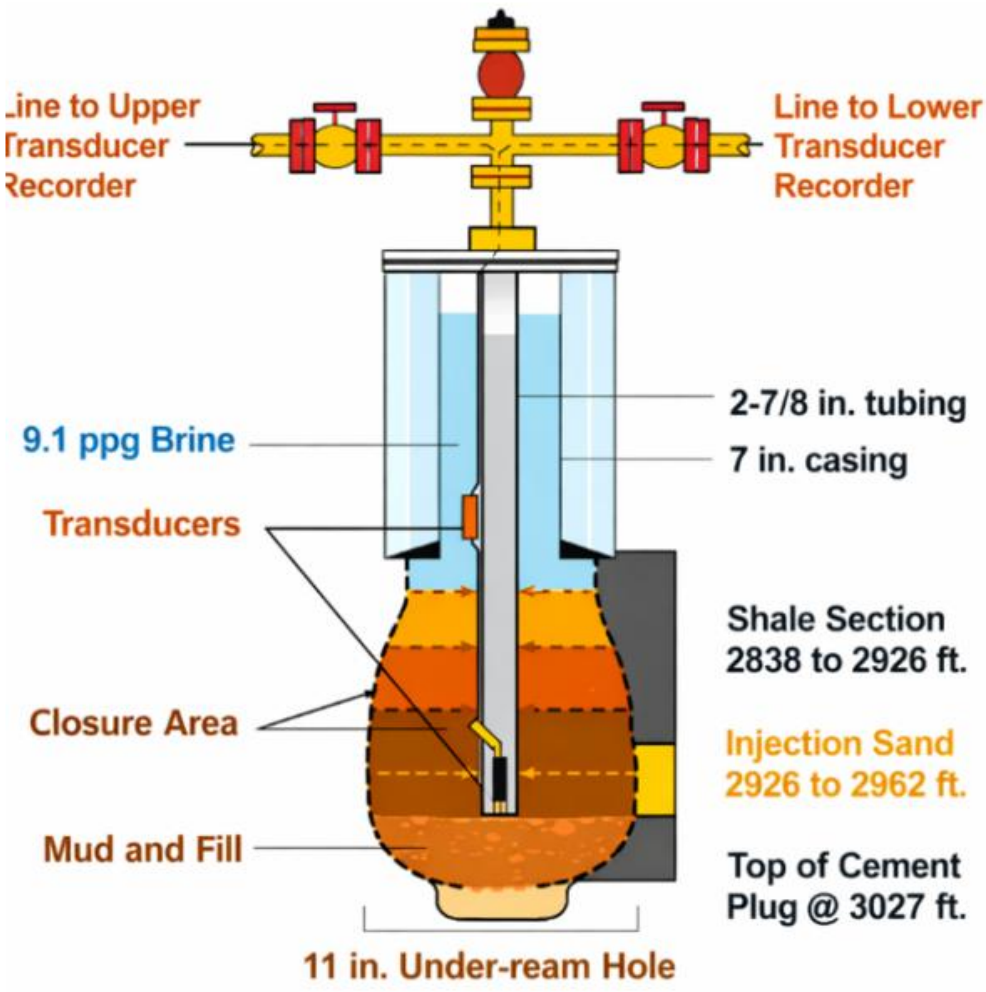

Figure 30. Well schematic after drilling mud was displaced and the well was shut in for pressure monitoring.

Shut-in response and early isolation

After mud displacement, the well was shut in and pressures were recorded continuously. Both transducers showed gradual pressure decline during recovery, but the lower transducer stabilized in less than about 4 days at roughly 1314 psi, while the upper transducer followed a different pressure path. Within about 3 to 5 days, both readings had approached static conditions, and the difference between the two pressure histories indicated that the upper and lower zones were no longer behaving as a single open hydraulic system. The original study interpreted this separation as the development of natural borehole closure across the shale interval.

Figure 31. shows the upper-transducer response from mud displacement through the end of the test. The main feature is the decline after shut-in, followed by a flatter trend once closure had developed. The later rise associated with post-injection annulus filling is also significant because it shows that the upper transducer remained responsive when fluid was introduced into the annulus.

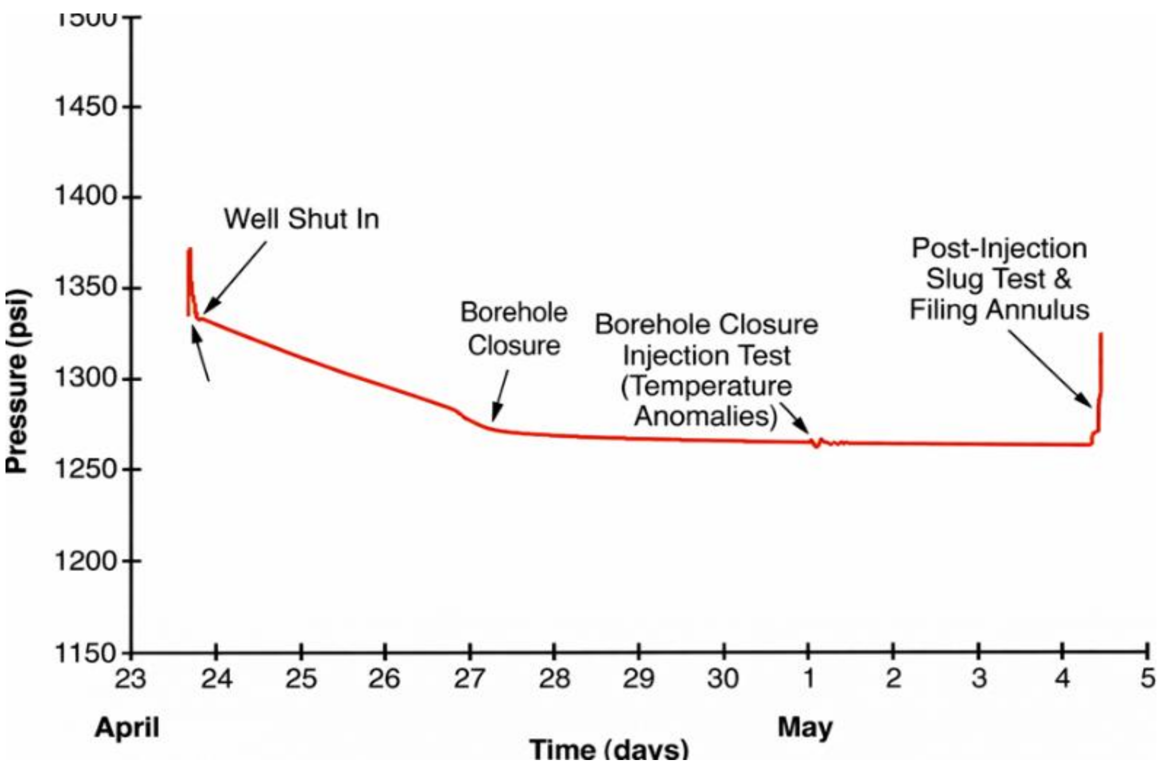

Figure 31. Upper-transducer pressure response from mud displacement through shut-in and post-injection verification.

Figure 32. shows the upper and lower transducer pressures together during the shut-in period. The lower interval approached stable formation pressure while the upper interval followed a different recovery trend, which is why this figure is central to the Orange

interpretation. It shows that the lower zone remained hydraulically distinct from the upper monitored section during recovery rather than behaving as part of one continuously open borehole system.

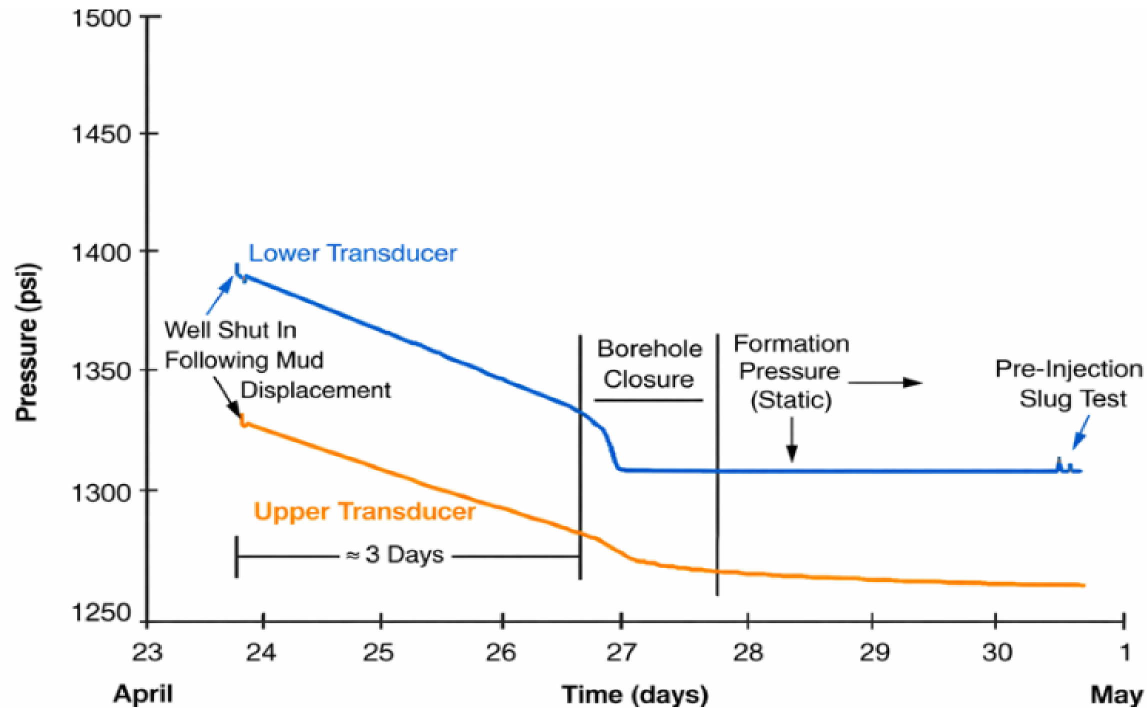

Figure 32. Upper and lower transducer pressure records during the shut-in period.

Pre-injection slug test and controlled pressurization

About one week after shut-in, a pre-injection slug test was performed to determine whether the screen remained open, whether the lower interval could sustain a measurable pressure buildup, and whether any response would appear in the upper transducer. Two series of five 2.5-gal brine slugs were injected. The lower transducer showed falloff behavior, confirming that the screen and lower interval were still hydraulically active, whereas the upper transducer showed no pressure response during or after the slug test. This result shows that the lower interval remained open to fluid entry even though communication with the upper monitored zone had already been lost. Oxygen-activation logging and pressure-isolation evidence.

The main proof stage of the experiment combined controlled pressurization with oxygen-activation logging. Logging was conducted under pressure-controlled conditions at about 90 psi above static formation pressure at three stations located 25, 50, and 75 ft above the test sand, corresponding to depths of 2900, 2875, and 2850 ft. No vertical fluid flow or upward channeling through the shale section was detected. The formation was then pressured to 110 psi above static, exceeding the EPA's 100 psi requirement, and the logging sequence was repeated with the same result. A third run was performed at 140 psi above static, again with no upward movement of fluid detected. Even the shallowest station, 25 ft above the injection sand, showed no evidence of upward channeling.

Post-injection verification and interpretation

After the logging and injection sequence, both transducers continued to be monitored, and the lower transducer returned to static pressure within about 2 to 3 hours. A post-injection verification test was then carried out by filling the annulus to the surface before the tubing and screen assembly were pulled. The upper transducer responded to this annulus fill as expected, but the lower transducer showed no pressure increase. That result confirmed that the lower interval was hydraulically isolated from the annulus by the end of the test.

Figure 33. shows the recorded pressure response during the post-injection verification test. Its significance is direct: the upper transducer responded when fluid was placed in the annulus, but the lower transducer did not. The original study interpreted that separation as confirmation that shale had closed around the tubing assembly in the open-hole section and had prevented pressure communication downward into the screened interval.

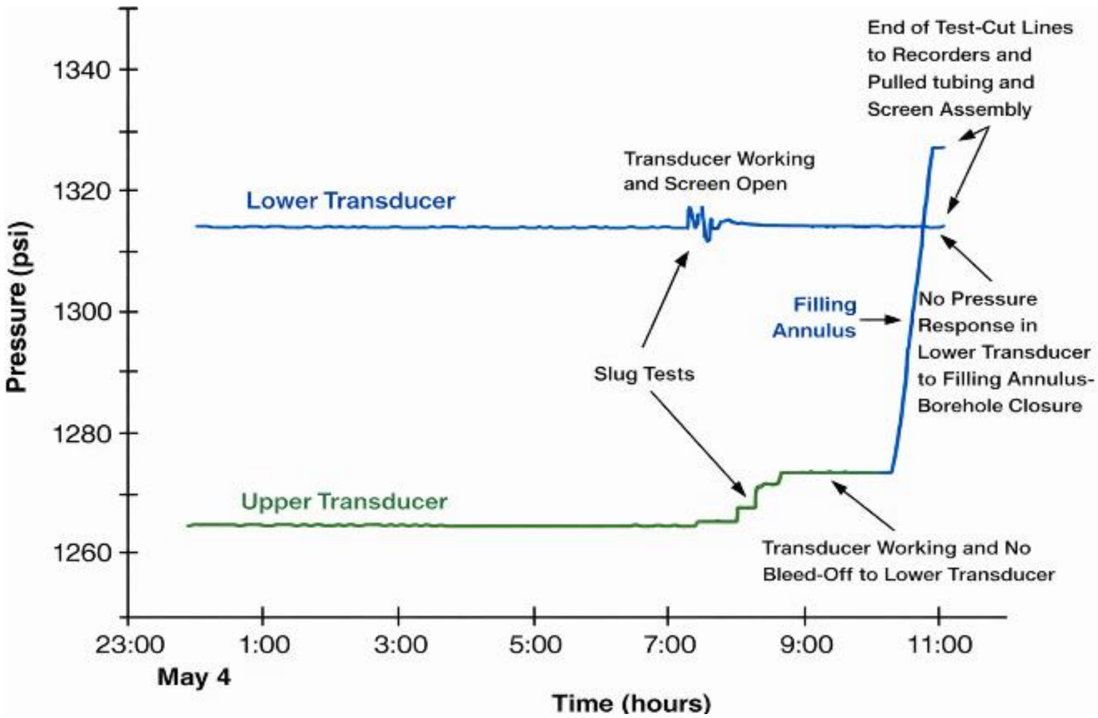

Figure 33. Post-injection verification showing upper-transducer response to annulus filling and no corresponding lower-transducer response.

Figure 34. presents a conceptual interpretation of the Orange borehole-closure process in three stages: before closure, during closure, and after closure. In the first panel, the underreamed open-hole section through the shale remains open, so the borehole still provides a continuous pathway above the lower screened interval. In the second panel, the shale moves inward and narrows the open section, showing progressive reduction of that pathway. In the third panel, closure has developed sufficiently to isolate the lower screened interval from the upper part of the borehole. The figure serves as a summary of the pressure records, oxygen-activation logging results, and post-injection verification described above.

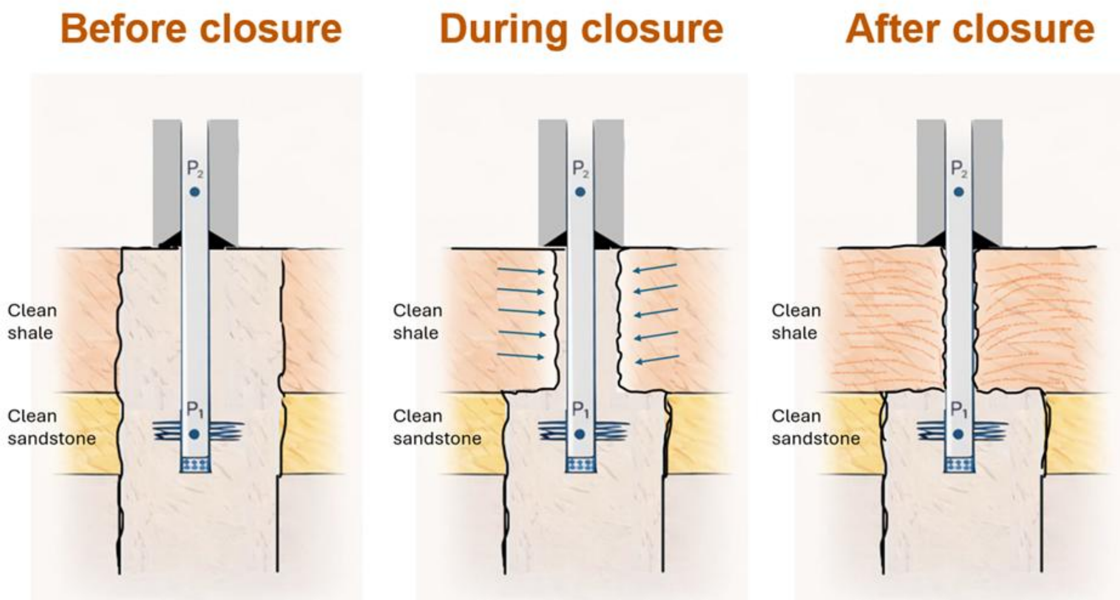

Figure 34. Conceptual interpretation of the Orange borehole-closure process, showing the borehole condition before closure, during closure, and after closure.

Taken together, the Orange test showed that an open-hole borehole through a shale interval did not remain hydraulically open under the tested conditions. The lower sand continued to accept pressure, but the overlying shale interval no longer transmitted pressure upward, oxygen-activation logging detected no upward channeling above the sand, and the post-injection annulus-fill test confirmed hydraulic separation between the upper and lower zones.

4.7. PROPOSED CCS BOREHOLE-CLOSURE TESTING FRAMEWORK

The purpose of the proposed CCS borehole-closure test is to adapt Orange experiment's hydraulic logic to a Gulf Coast Class VI setting. In Orange, the field question was whether an open-borehole analogue of an abandoned penetration would remain hydraulically open across a shale interval under conservative pressure conditions. In the CCS version, the question is whether open-borehole closure across a shale interval remains plausible under deeper, storage-relevant conditions, and whether such behavior is important enough to be considered in pathway-based legacy-well risk assessment.

Site selection and benchmark to Orange

The Houston-New Orleans coastal Oligocene–Miocene corridor is the most appropriate search area for a Class VI adaptation because it combines active Gulf Coast storage interest with the same broad clastic reservoir–seal architecture that made the Orange test interpretable. In this regional setting, sand-rich Frio and related Oligo–Miocene reservoir intervals occur within a shale-dominated stratigraphic succession, while marine shale units such as the Anahuac provide laterally extensive confining facies. Orange analogue was interpretable only where a pressure-transmissive sandstone was overlain by a lower-permeability shale barrier (Hammes et al., 2003; Clark et al., 2005). It should satisfy five practical criteria. First, the lower interval should be a permeable storage reservoir, preferably a Miocene or Frio sandstone, capable of producing a clear and interpretable pressure response during injection and shut-in. Second, the reservoir should be overlain by a thick, laterally continuous, shale-dominated confining interval that is clay-rich and mechanically ductile enough to serve as a meaningful closure candidate. Third, burial depth should be greater than Orange and representative of Gulf Coast Class VI conditions, but it should not be so great that brittle behavior, drilling complexity, or poor test interpretability dominate the response. Fourth, the site should be structurally simple enough that upper- and lower-zone pressure behavior can be interpreted clearly, with major through-going faults avoided at the test location. Fifth, the site should be representative of realistic Gulf Coast storage architecture rather than an unusual outlier chosen only for convenience.

In practical terms, the ideal site is one where a reservoir-quality sandstone is overlain by a shale interval capable of separating upper and lower monitored zones, while burial conditions remain compatible with time-dependent deformation of the shale. The monitored separation in the test well does not need to reproduce the full thickness of the regional confining system. Instead, it should span the hydraulically relevant portion of the shale interval being evaluated. This distinction is intended to test whether an open borehole drilled across a shale-reservoir system can develop hydraulic isolation under Class VI-relevant conditions.

For the confining interval, screening should focus on functional seal behavior rather than on matching Orange mineralogy exactly. The most important requirements are very low permeability, lateral continuity, sufficient thickness to separate the upper and lower monitored zones, and mechanical behavior that is more ductile than brittle. In practical terms, candidate intervals should be clay-rich mudrocks with limited quartz-rich and silt-rich material, because increasing quartz content and coarser silt-sized fractions are generally less favorable for ductile borehole narrowing and more compatible with brittle behavior. Mineralogy still matters, but for this test the central question is not whether the shale reaches a single target smectite percentage. The more important question is whether the interval behaves as a continuous, low-transmissivity, non-brittle confining unit under the selected burial and pressure conditions (Fisher et al., 2023; Loizzo et al., 2017).

At the end of site screening, the candidate Class VI site should be compared directly to Orange using a benchmark table that includes purpose, geologic setting, depth, lower reservoir interval, overlying shale interval, reservoir quality, shale mineralogy, internal test fluid, well geometry, pressure program, monitoring package, closure timescale, and interpretive role. That comparison makes clear that the CCS design is not a blind copy of Orange. It is an explicit adaptation from a disposal-era field analogue to a storage-era validation experiment.

Well construction, completion, and borehole-condition control

The recommended test design is a dedicated research well constructed to preserve the essential Orange logic while remaining scientifically interpretable in a Class VI setting. The well should penetrate the selected storage reservoir and its overlying shale confining interval. Casing should be cemented from surface to a casing shoe set above the test section, so that the lower part of the shale and the uppermost part of the storage reservoir remain as an open-hole interval. As in Orange, the open-hole test section should be underreamed rather than left at nominal drilled diameter, because the point of the experiment is to evaluate whether a conservative shale-bounded opening remains hydraulically open or closes with time. Injection tubing should be run inside the casing and extended into the lower part of the test interval, with a short screened or perforated tailpiece positioned in the reservoir-side portion of the open-hole section. A lower pressure transducer should be placed in or immediately adjacent to the lower open interval, while an upper pressure transducer should be installed above the shale in the cased section to test whether pressure communication develops across the confining interval. In this configuration, the casing and cement define the upper completed section, while the underreamed open-hole interval provides the section in which closure or continued communication is actually tested.

Borehole condition at the time of drilling must also be controlled because the geometry of the cavity affects how later closure behavior is interpreted. If the interval is already enlarged, fractured, or unstable during drilling, subsequent pressure response may reflect pre-existing borehole damage as much as time-dependent shale deformation. For that reason, drilling records should document mud weight, fluid losses, and other indicators of hole stability, while caliper logs and other borehole-condition logs should be used where feasible to identify washout, breakouts, or induced fractures before testing begins. The purpose is to ensure that any later loss or gain of hydraulic isolation can be tied more confidently to formation behavior.

Baseline characterization

Before any shut-in or injection testing begins, the site should be characterized thoroughly. The baseline program should include static pressure in the lower zone, static pressure above the shale, reservoir temperature, shale temperature where measurable, borehole geometry from caliper logs, lithology from standard wireline logs, shale thickness and continuity, shale mineralogy if core or cuttings are available, reservoir porosity and permeability, and the fluid condition in the borehole and test interval. This baseline is important because the Orange result was only interpretable because the geometry of the test interval, the transmissivity of the lower sand, the overlying shale, and the condition of the borehole were all known before pressure loading began. In the CCS version, the same principle applies: closure can only be interpreted if the initial hydraulic and geometric condition of the test well is established first.

Closure-observation phase

After drilling, logging, and fluid conditioning, the first active phase should be a shut-in observation period without injection. The purpose is to determine whether time-dependent shale deformation begins to reduce hydraulic communication even before the system is exposed to storage-relevant fluid conditions. This phase should follow the Orange logic closely. Both upper and lower pressure sensors should record continuously, and interpretation should focus on lower-zone pressure decline or stabilization, upper-zone pressure behaviour, and evidence that the two zones cease to communicate hydraulically. The shut-in period should continue until hydraulic separation develops, conditions stabilize without further change, or a predefined maximum observation time is reached. Because Class VI test settings are deeper than Orange, the CCS version should be prepared to observe a slower response if closure develops more gradually at depth.

Phase A: baseline liquid-response testing with brine

The first injection phase should use brine in order to preserve direct continuity with Orange. Brine-first testing is useful because it isolates the mechanical and hydraulic behaviour of the system from the added complexity of storage-relevant gas-phase effects. The lower zone should first be tested using low-rate injection below the shale to confirm that the reservoir interval is responsive, after which pressure should be held and monitored in both the lower and upper zones. If lower-zone pressure increases while the upper zone remains unresponsive, the shale is acting as a hydraulic barrier under Orange-like fluid conditions. This phase is therefore the clearest bridge between the Orange benchmark and the deeper Class VI adaptation.

Phase B: CCS-relevant fluid exposure

After baseline closure behaviour has been characterized with brine, the test should transition to a more storage-relevant fluid condition. The preferred option is exposure to CO_2-saturated brine followed by small, controlled supercritical CO_2 pulses below the shale. This option is preferred because it captures pressure effects, gas-brine phase behaviour, and near-well fluid conditions that are more relevant to CO_2 storage than brine alone. A secondary option is nitrogen gas as a stand-in where CO_2 handling, corrosion, safety, or permitting constraints are limiting. Nitrogen does not reproduce CO_2-specific chemistry, but it does reproduce important gas-phase features such as compressibility and buoyancy. The interpretation of the phases should therefore be stated clearly: brine tests Orange-style hydraulic behaviour; CO_2-saturated brine tests near-well storage fluid conditions; CO_2 pulses test multiphase transmission and buoyancy-relevant behaviour; and N_2 tests gas-phase compressibility and buoyancy without CO_2-specific chemistry. Over the duration of a field test of this kind, the main value of CO_2 exposure is expected to lie in fluid-property and multiphase effects.

Injection-pressure strategy

The pressure program should be stepwise and explicitly tied to the local fracture limit. In Orange, pressure checks were performed at about 90, 110, and 140 psi above static, but a Class VI version should not simply copy those values. Instead, the pressure schedule should be referenced to a local leak-off test, formation integrity test, or equivalent fracture-limit determination so that each stage remains sub-fracture and site-specific. A good strategy is to begin with low-rate injection below the shale, hold pressure and monitor both zones, increase pressure in controlled increments, stop each step below fracture pressure, and repeat the sequence under the CCS-relevant fluid condition.

Monitoring and diagnostics

A CCS borehole-closure test should use multiple lines of evidence. In practice, Class VI monitoring plans are designed to show that injection is operating as planned, that the CO_2 plume and pressure front are moving as predicted, and that there is no endangerment to USDW. For that reason, the monitoring package should combine continuous operational measurements with targeted diagnostics that can identify pressure communication, fluid movement, saturation change, and possible leakage pathways.

The primary monitoring layer should consist of continuous measurements of injection pressure, injection rate, injection volume, annulus pressure, and downhole pressure and temperature. The Archer Daniels Midland CCS#2 Class VI testing and monitoring plan is a useful model here because it specifies continuous monitoring of annular pressure, injection pressure at the surface and near the packer, injection rate, injection volume, and temperature at the surface, near the packer, and along the wellbore using distributed temperature sensing (ADM, 2021). For a borehole-closure test, those measurements form the core evidence needed to evaluate whether the tested interval remains hydraulically isolated during and after injection.

Temperature monitoring should be included because leakage can disturb the normal thermal profile along the wellbore and create localized anomalies that help identify fluid movement near the test interval. Zhang et al. (2018) showed that distributed temperature sensing can be used for real-time leakage detection along an injection-well casing and argued that leakage identification should be based on both temperature-history plots at selected depths and vertical temperature profiles through time. They also emphasized that interpretation should be combined with numerical simulations and confirmed by warm-up behaviour after injection stops. In the proposed test, temperature data should therefore be treated as a supporting diagnostic for possible leakage or crossflow.

Acoustic or noise logging should also be part of the diagnostic package because active gas movement can generate detectable sound, particularly where leakage produces bubbling or localized flow behind casing. Bergès et al. (2012), Haris et al. (2023), and Li et al. (2021) show that passive acoustic methods can detect and in some settings quantify gas release, although performance depends on background noise and site conditions. At the well scale, Marbun et al. (2019) show that acoustic leak-detection noise logging can help identify leak location and flow path behind casing, especially when interpreted together with temperature anomalies. In the proposed CCS test, acoustic or noise logging should therefore be treated as a supporting diagnostic for active gas movement or bubbling associated with leakage, to be interpreted together with pressure, temperature, and other data.

Pulse neutron or Reservoir Saturation Tool (RST)-type logging is also useful because it provides a cased-hole method for detecting changes in fluid saturation near the wellbore. Müller et al. (2007) used repeated RST logs to document plume movement and saturation changes in a saline formation, and later CCS field applications similarly describe pulsed neutron capture logging as an effective cased-hole tool for identifying the presence of reservoir fluids near wells and aiding the monitoring of injected CO_2 migration. In the proposed test, pulse neutron logging should therefore be used as a supporting saturation-monitoring tool, especially where baseline and repeat surveys can be compared through time. Its main value is to indicate fluid substitution or migration near the monitored interval.

Tracer-based methods may be used as additional, case-specific diagnostics. Roberts et al. (2017) note that tracers can help detect, attribute, and quantify CO_2 leakage, but also emphasize that tracer selection must consider environmental behaviour, background levels, and permitting constraints.

Post-test verification and interpretive criteria

After the pressure-step and CCS-fluid phases are complete, a post-test verification stage should confirm whether hydraulic isolation persists. Recommended methods include an annulus-fill test, repeat slug testing, repeat step-pressure testing, repeat flow logging, and tracer confirmation if tracers were used.

The interpretive rule should remain straightforward. If the lower zone responds to injection while the upper zone shows no meaningful pressure response, no upward flow evidence, and no diagnostic evidence of communication, then the shale is functioning as a hydraulic barrier under the tested conditions. If both zones respond, then the pathway remains open or partly open. If the result changes between brine and CCS-relevant fluid exposure, then storage-relevant fluid conditions materially affect pathway behaviour and must be considered explicitly in legacy-well screening.

CHAPTER V: CONCLUSIONS AND RECOMMENDATIONS

5.1. CONCLUSIONS

This thesis examined how legacy well risks are defined, screened, and classified for geologic CO_2 storage in the Gulf Coast Basin, and whether the logic used in current classification frameworks is adequately supported by empirical evidence, operational experience, and Gulf Coast geological context. The need for this work arises from a basic tension in CCS development. On one hand, the Gulf Coast Basin is one of the most favorable regions in the United States for large-scale CO_2 storage because it contains thick sedimentary successions, regionally extensive reservoir-seal pairs, and a large concentration of proposed storage projects. On the other hand, the basin contains a very large and historically layered population of legacy oil and gas wells, many of which were drilled and abandoned under technical and regulatory conditions very different from those that now govern Class VI storage projects.

The central conclusion of this thesis is that legacy-well risk in CCS is best evaluated through a pathway-based and evidence-informed framework rather than through generalized well descriptors alone. Existing classification methods remain useful, especially for early screening of large well inventories, but many of them still combine uncertainty, hazard, and true project-relevant leakage risk in ways that can overstate or blur the actual containment significance of a given well. The strongest frameworks are those that move beyond simple counts, age classes, or record completeness and instead evaluate whether a well is hydraulically relevant to the storage system, whether it contains a plausible migration pathway, and whether the project's pressure conditions are sufficient to drive fluid movement along that pathway.

A review of published legacy-well classification approaches showed that the literature is not uniform. Earlier and more foundational methods, especially Watson and Bachu, are strongly centered on intrinsic well attributes such as annular cement coverage, casing integrity, corrosion, abandonment condition, deviation, and regulatory vintage. Later CCS-oriented methods increasingly incorporate geologic penetration, AoR review position, hydraulic relevance, corrective-action accessibility, and project-specific screening logic. This progression reflects a broader shift in the literature from general well-integrity screening toward more site-specific, pathway-based assessment. Even so, the review also showed that consistency remains limited across published methods, and that the same well could be ranked differently depending on the framework applied.

The historical incident analysis provided an important empirical counterweight to purely theoretical classification logic. The RRC of Texas well-control dataset showed that the reported field record is dominated by operational incidents, incomplete remarks, and events that do not necessarily indicate long-term containment failure. Of the 1,502 incidents reviewed, 1,004 lacked enough detail to support assignment of a clear failure mechanism, and among the interpretable records the largest categories were short-term operational failures rather than confirmed deep leakage pathways. Categories more relevant to long-term containment, such as hydrocarbon leak, spontaneous brine flow, corrosion-related degradation, and geologic integrity breach, were present but made up a much smaller share of the total record. It shows that raw incident counts and broad well-control histories are not sufficient by themselves to define CO_2-storage risk. Historical records are most useful when interpreted by failure mechanism and physical relevance rather than by total frequency alone.

The comparison with Class I and Class II injection practice reinforced this interpretation. Although these injection systems are not identical to Class VI storage, they provide a much longer operational history of how injection-related risk has been handled in practice. The main lesson from that experience is that mature regulatory practice treats relevance physically. Wells are screened first by whether they lie within the pressure-affected system and whether they can plausibly act as conduits for vertical fluid movement, and only then are static well descriptors interpreted in that operational context. Mechanical integrity is not assumed from age or appearance; it is demonstrated repeatedly through testing and monitoring. This is one of the strongest reasons to use Class I and Class II practice as a calibration reference for CCS legacy-well screening. It shows that pathway potential, hydraulic relevance, and pressure communication should be treated as central questions.

Another important conclusion of this thesis is that natural sealing should not be ignored, but it also should not be generalized. The literature reviewed in this study shows that some pathway types may become less transmissive through time in Gulf Coast settings. Mudcake can create an initial low-permeability lining in some open-hole conditions. Weak clay-rich sediments can undergo time-dependent viscoplastic deformation. Creeping formations may close or clamp microannuli. In some CO_2-rich systems, existing defects may also evolve toward lower permeability through precipitation, corrosion-product accumulation, or deformation-assisted closure. These processes are physically credible and, in some cases, field-relevant. However, they are not equally applicable to all leakage geometries. They are much more plausible for small stress-sensitive pathways and shale-bounded openings than for large internal casing voids, severe corrosion, failed or missing plugs, or uncased penetrations that connect multiple intervals. For that reason, natural sealing should be incorporated into legacy-well evaluation as a qualified modifying process.

The Orange borehole-closure test provided the strongest field-based analogue. Its value lies in the fact that it was not based on one suggestive observation alone. Instead, the interpretation of closure depended on a consistent set of observations: the lower interval continued to accept pressure, the upper and lower monitored zones separated hydraulically during shut-in, oxygen-activation logging detected no upward channeling through the overlying shale, and post-injection annulus-fill testing confirmed hydraulic separation between the upper annulus and the lower screened interval. Taken together, those results show that an open-hole borehole through a hale interval did not remain hydraulically open under the tested conditions.

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