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A decade of progress in understanding and managing legacy well integrity for geologic carbon storage

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ABSTRACT

This study reviews a decade of research progress in legacy well integrity and risk management for geologic carbon storage (GCS) to commemorate the 20th anniversary of the Intergovernmental Panel on Climate Change's 2005 Special Report on Carbon Capture and Storage. In the past ten years, legacy well research has benefited from global efforts to constrain emissions from abandoned oil and gas wells, a continued focus on well materials performance in the presence of CO_2-rich fluids, and practical experience gained through GCS implementation. Field measurements of abandoned well emissions show that leakage is not universal or catastrophic but forms a continuum of low-to-moderate fluxes that depend on isolation integrity and environmental attenuation. Materials research has constrained the conditions under which Portland cements exhibit self-sealing and non-sealing behaviors, and has identified the impact of geomechanical properties, non-uniform pathway apertures, multiphase flow, and impurities in the CO_2 stream, on leakage pathways as important new areas for investigation. GCS projects at brownfield sites have inspired the creation of new workflows that integrate various tools and technologies to manage legacy well leakage risks. GCS implementation has also motivated a push towards scenario-based well modeling that directly informs permit applications. These advances inspire new research questions for the coming decade, particularly around the level of legacy well leakage risk that is environmentally acceptable and tolerable to stakeholders when sequestering millions of tonnes of CO_2 annually.

1. Introduction

Legacy wells are any active, suspended, or abandoned wells drilled prior to geologic carbon storage (GCS) operations for hydrocarbon production, waste disposal, geothermal projects, or another purpose. The 2005 Intergovernmental Panel on Climate Change's (IPCC) Special Report on Carbon Capture and Storage (SRCCS) identified legacy wells as one of the greatest challenges for GCS (IPCC, 2005). At the time, the carbon capture and storage (CCS) industry was nascent with only four active projects dedicated to CO_2 injection (Gale et al., 2001; IPCC, 2005). However, there were many CO_2 enhanced oil recovery (EOR) and acid gas injection operations, which provided a technical base of understanding for the development of GCS (Bachu and Gunter, 2004; White et al., 2004). The legacy well discussion in the SRCCS is broad and outlines the basic elements of legacy well management: locating wells, characterizing their integrity, evaluating leakage risks, and mitigating risks through plugging or remedial action. The key legacy well research gaps identified in the SRCCS were: (i) understanding well integrity and well leakage, especially well material degradation from exposure to supercritical CO_2 and acidified brine, and (ii) the development of risk assessment methodologies capable of predicting the long-term performance and containment risk of legacy wells at GCS sites (IPCC, 2005).

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GCS expanded globally over the following decade (Finley, 2014; Flett et al., 2009; Tanaka et al., 2014; Torp and Gale, 2004; Xie et al., 2014). Between 2005 and 2015, many countries developed regulations for underground CO_2 injection, and significant technical experience was gained through international GCS field projects which cumulatively injected 50 million tonnes of CO_2 (Jenkins et al., 2015). Pawar et al. (2015) reviewed advances made in GCS risk assessment over this period for the *International Journal of Greenhouse Gas Control's* special issue commemorating the 10-year anniversary of the SRCCS and in the process highlighted progress relating to legacy well research. Researchers pursued efforts that addressed the well integrity and risk assessment knowledge gaps identified in the SRCCS report. Field and experimental studies showed that, while supercritical CO_2 and acidified brine react with well materials, exposure to these fluids does not always degrade the integrity of a well as both Portland cement and low-carbon steel casings are resistant to degradation in environments where the degree of fluid exposure is limited (Carey, 2013; Carroll et al., 2016; Crow et al., 2010; Duguid et al., 2011; Han et al., 2012). New qualitative (e.g., bow tie, risk register), semi-quantitative, and quantitative risk assessment methods (e.g., evidence supported logic and GCS system performance models) that use expert elicitation, leakage incident frequency from analogous operations (e.g., gas storage, oil and gas production), and well leakage modeling were also developed (Bourne et al., 2014; Hnottavange--Telleen, 2014; Oldenburg et al., 2009; Pawar et al., 2014). Key research gaps identified in 2015 were the range of conditions over which well materials experience self-healing behavior and the need for case studies that help validate and reduce the uncertainty associated with quantitative risk assessment methods (Pawar et al., 2015).

Another decade has elapsed since the publication of the SRCCS. Today, hundreds of GCS projects are in various phases of development across the globe and 384.6 million tonnes of CO_2 have been sequestered in the subsurface (Gao and Krevor, 2025; Global CCS Institute, 2025). A substantial number of active and planned projects are operating in reservoirs penetrated by legacy wells. For example, at least 534 legacy wells are in the proposed areas of 63 GCS projects in the United States (U.S.) alone (Table 1). Legacy well integrity and risk management research has progressed alongside this implementation of GCS. In this study, we review the past decade (2015–2025) of legacy well research to build on the reviews contained in the SRCCS and Pawar et al. (2015). After providing background on legacy well integrity and leakage (Section 2), our review considers three major areas: field observations of well integrity and well leakage (Section 3), processes affecting leakage pathways (Section 4), and legacy well risk management (Section 5). We conclude by highlighting current knowledge gaps and future research needs to help shape the next decade of legacy well research.

Table 1
Count of legacy wells that penetrate the caprock of active or proposed GCS reservoirs as described in U.S. Class VI permit applications organized by basin. Legacy well information was only available for 63 of the 116 active permit applications. Permit applications were accessed through CCUS Map ("CCUS Map," 2025).

Basin	Permit Applications	Legacy Well Count
Anadarko	1	4
Appalachian	2	0
Arches	3	0
Denver	4	1
Gulf Coast	23	392
Illinois	9	0
Permian	2	3
Powder River	1	17
Sacramento	5	76
San Joaquin	1	15
Williston	8	16
Greater Green River	2	10
San Juan	1	0
Palo Duro	1	0
Total	63	534

2. Well integrity and leakage

Leakage is the primary concern associated with legacy wells at GCS sites. Pre-existing wells that penetrate CO_2 injection reservoirs or their caprocks can provide a direct pathway for reservoir fluids to escape the permitted storage zone (Gasda et al., 2004; Iyer et al., 2022). However, there is no universally accepted regulatory definition of a well leak across jurisdictions. In this review, we use the following definitions for terms related to well leakage:

- The **permitted storage zone** is a three-dimensional volume within a geologic formation(s) that is approved in a CO_2 injection permit, outside of which the movement of reservoir fluids would be a permit violation. In the U.S., the permitted storage zone is the injection zone, which is defined as a "geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive CO_2 through a well or wells associated with a geologic sequestration project." In Europe, the permitted storage zone aligns with the storage complex, which is defined a as a volume area within a geologic formation used for geological storage of CO_2 (i.e., the storage site) and the surrounding geologic domain that can impact storage integrity and security including secondary containment formations (European Commission, 2009; U.S. EPA, 2018).
- **Well leakage** is the uncontrolled flow of fluids such as injected CO_2, brine, or hydrocarbons through a wellbore and into the surrounding environment (i.e., subsurface, atmosphere, or ocean) above the boundary of the permitted storage zone (adapted from Oldenburg et al. 2009). If CO_2 leakage enters the linked ocean-atmosphere system it is considered an emission.
- **Fluid migration** is the upward movement of fluids through a pathway (e.g., uncemented annulus, microannulus) within a wellbore. Fluid migration becomes leakage if the migrating fluids escape the well system above the permitted storage zone.

Another useful set of terms to define are related to well integrity:

- **Well integrity** is defined as the "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well" (NORSOK, 2013).
- **Well integrity issues** describe fluid migration through a well that is contained within a well system.
- **Well integrity loss** occurs when migrating fluids escape the well system and enter the surrounding environment. Well integrity loss is synonymous with well leakage if fluids escape the well system above the permitted storage zone.

Well leaks require a (i) driving force, (ii) a pathway for fluids, and (iii) an outlet or mechanism for the release of fluids from the well system. CO_2 injection creates the driving force for legacy well leaks as increasing reservoir pressure above hydrostatic can drive the flow of CO_2, brine, and other reservoir fluids upward along a wellbore. Supercritical CO_2 is also less dense than brine and will naturally migrate upward through pathways along a well due to buoyancy. The degree to which CO_2 injection drives leakage is impacted by the characteristics of the reservoir and the injection schedule (Torsæter et al., 2024). The presence of fluid migration pathways in legacy wells depends on their construction and abandonment design, and the integrity of the well materials, both of which vary widely (Fig. 1). Improper installation or breakdown of well materials during the operational lifetime of the well can also create leakage pathways along wellbores. Additionally, GCS creates unique chemical stresses in the subsurface, which have been shown not to impact well materials in restricted flow environments but must be considered when evaluating leakage pathways (Zhang and Bachu, 2011). Common outlets for fluids from the well are subsurface

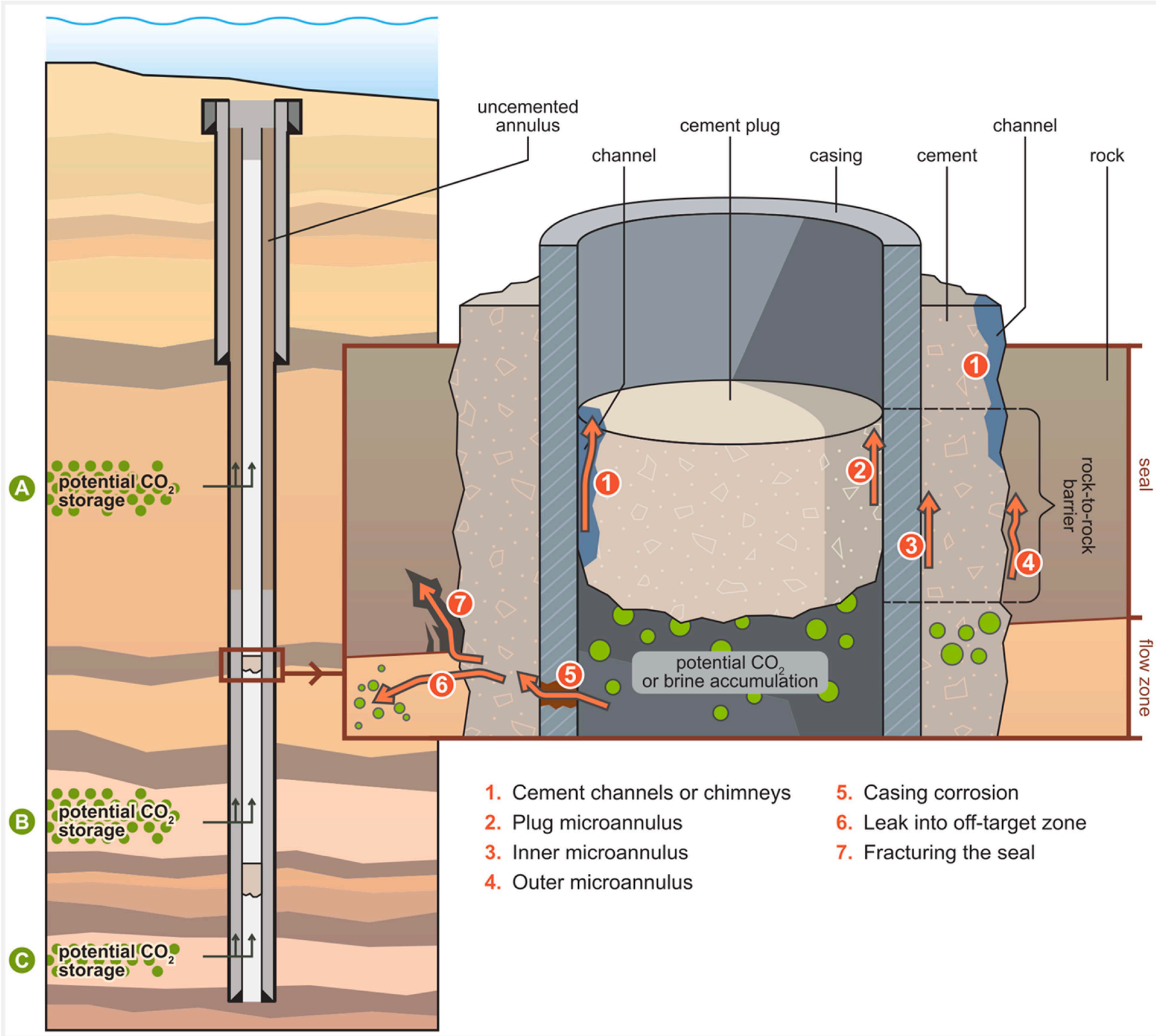

Fig. 1. An example well schematic for a modern legacy well showing (left) CO_2 entry points into a well system from multiple potential CO_2 storage zones, and (right) seven fluid migration pathways and various formation mechanisms. The storage scenarios shown (A, B, and C) represent decreasing degrees of leakage risk from A to C. In A, injected CO_2 and reservoir brine can migrate upward through an uncemented well annulus unimpeded by well materials. In B and C, reservoir fluids must migrate through increasing lengths of annular cement and an increasing number of well plugs.

pathways (e.g., faults, fractures networks, high permeability zones) that intersect the well where integrity has been lost and vents. Release mechanisms include over-pressuring the outermost annulus of the well through high sustained casing pressure or, in extreme circumstances, well material failure and blowout (Lackey and Rajaram, 2019). Estimated legacy well leakage rates vary widely based on GCS site operating conditions and leakage pathway characteristics. For example, CO_2 leakage rate estimates vary between 0.003 and 1.4 tonnes per day for microannular flow and >3000 tonnes per day for well blowouts (Moghadam and Amiri, 2025; Oldenburg and Pan, 2020).

3. Field observations of well integrity

Large-scale GCS projects are only now emerging. Consequently, there are almost no direct observations of CO_2 leakage along legacy wells that intersect or lie within candidate GCS sites outside controlled experiments. This absence of real-world evidence presents a persistent challenge for assessing containment integrity: while numerical and geomechanical models can simulate potential leakage, their parameterization and validation remain largely unconstrained (Vielstädte et al., 2019). However, a subset of this well population, which now intersects many prospective storage domains, has been widely observed across multiple regions to emit methane (CH_4) and other hydrocarbons under post-abandonment conditions, although reported leakage rates span a wide range. In this context, methane leakage from legacy petroleum wells, particularly when associated with deeper hydrocarbon sources rather than shallow biogenic production, offers an instructive analogue.

Mechanistically, the pathways documented in methane-emitting wells are largely the same as those that govern CO_2 migration through equivalent infrastructure under storage conditions. Debonded cement–casing interfaces, corroded tubulars, and degraded plugs constitute mutual leakage routes (Bai et al., 2016; Kiran et al., 2017; Vrålstad et al., 2019). Field investigations of CH_4-emitting wells also illustrate how leakage manifests at the surface and the practical challenges of detection. Consequently, the methane-leakage record constrains the likely frequency, geometry, and progression of integrity failure in legacy wells that may later become exposed to stored CO_2. What differs are the fluid properties and near-surface behavior: CO_2 is denser and significantly more soluble in water than CH_4, it is reactive with cement and formation water, and, unlike methane, lacks a microbial oxidative sink in soils (though dissolution and plant uptake can modulate near-surface persistence) (Celia et al., 2009; Le Mer and Roger, 2001). These physical and chemical differences influence the style and driving forces of leakage, for example, the greater density of CO_2 reduces buoyancy and may slow upward migration, but they do not substantially alter the underlying probability of barrier failure or leakage initiation. Recognizing these distinctions allows lessons from methane leakage to be applied judiciously, rather than directly, to define a realistic envelope for leakage frequency and magnitude against which GCS containment models can be benchmarked.

Over the past decade, increasing well integrity testing requirements and a global push to constrain sources of greenhouse gas emissions has progressed the collective understanding of petroleum well integrity. Researchers have analyzed large regulatory datasets of operator performed integrity testing results to diagnose sustained casing pressure (SCP) and surface-casing-vent flow (SCVF) in wells—two widely used indicators of integrity issue occurrence. Researchers have also used a variety of field methods to measure methane emissions from abandoned oil and gas wells. Together, these studies provide insight into the frequency and magnitude of well integrity loss and associated leakage, although direct linkage to reservoir-scale flow is not established in all cases.

3.1. Frequency and detection of leakage

Understanding how often legacy wells leak is central to evaluating CO_2 containment risks at GCS sites. In this context, incidence refers to the baseline probability that a given legacy petroleum well could act as a pathway for fluid migration once intersected by a CO_2 plume. Recent studies have begun to quantify this empirically, revealing that integrity loss is not exceptional and that observed frequencies depend strongly on the methods used to evaluate integrity and the well populations examined.

Direct ground campaigns that measured methane emissions from fully or partially plugged and abandoned wells provide a dataset that is most relevant to GCS (Schout et al., 2019). In one study, detailed site-level investigations reported indications of leakage in roughly half of the nine surveyed wells when using sensitive ground methods (Cahill et al., 2025, A.G. 2023). A broader regional study in northeastern British Columbia combined aerial detection with targeted ground verification (Pozzobon et al., 2023). Methane plumes were detected from a few percent of > 400 non-producing wells in the aerial survey, and roughly one-third of those detections were confirmed by ground-based flux measurements (i.e. ~1–2% of the full scanned set under the survey conditions). The low apparent incidence primarily reflects higher detection thresholds and sampling logistics of aerial methods (instrument sensitivity, altitude, plume-stability criteria, revisit rate, etc.), not necessarily an absence of leakage. Ground-based techniques with detection limits near ~1 g CH_4 m^{-2} d^{-1} (often lower, method-dependent) reveal that measurable gas release is common when investigations are sufficiently sensitive. Therefore, the pattern is clear: the more sensitively we look, the more we find.

Large regulatory databases that record operator-performed well integrity tests for SCVF or SCP across mixed active, suspended, and abandoned wells show integrity issues in roughly 0.5–15% of cases, depending on jurisdiction and reporting threshold (Davies et al., 2014; Ingraffea et al., 2014; Lackey et al., 2025, 2021; Sandl et al., 2021; Watson and Bachu, 2009; Wisen et al., 2020). It should be noted, however, that SCP and SCVF do not always indicate a total loss of containment and are permitted in producing wells within specified limits in some jurisdictions. SCVF may also be managed as a regulatory risk-mitigation measure to protect shallow groundwater resources. Tested well populations predominantly include active wells, which provide insight into the integrity of modern wells at GCS sites, with interpretation and regulatory response to indicators such as SCVF varying by jurisdiction. Reported figures likely represent conservative lower bounds for integrity issue frequency, influenced by self-reporting and minimum-flow criteria. Nevertheless, they demonstrate that integrity impairment is widespread in mature well populations and that detectable flow or pressure anomalies are a routine feature of well infrastructure. Field investigations of smaller subsets typically fall within or above this range, confirming that regulatory data undercount low-rate and intermittent emissions in some jurisdictions (Boothroyd et al., 2016; Kang et al., 2014; Lebel et al., 2020).

Across both evidence classes, leakage frequency is conditional on context. Older wells, those drilled with deviated geometries, or those abandoned before modern cementing and verification standards tend to show higher probabilities of detectable leakage (Gonzalez Samano et al., 2023; Pullen et al., 2025; Sandl et al., 2021). In contrast, contemporary abandonment programs reduce, but do not eliminate, risk. Incidence should therefore be treated as a context-dependent distribution, not a fixed value. Comparable European studies report similar orders of magnitude, emphasizing the generality of this behavior (Blumenberg et al., 2025; Boothroyd et al., 2016; Vrålstad et al., 2019). From a CCS perspective, the analogue message is straightforward: within any storage domain containing legacy wells, measurable gas release from a subset of wells is likely if investigations are sufficiently sensitive. Leakage frequency is thus an inherent property of mature well populations rather than an anomaly. However, the majority of observed indicators (e.g. SCVF) reflect shallow annular or near-surface leakage, whereas CCS relevance arises primarily from the subset of cases involving deeper, reservoir-connected pathways.

3.2. Magnitude, variability, and consequence of leakage

The magnitude of leakage determines consequence. For legacy wells intersecting prospective storage domains, the rate and persistence of any flux, determine its environmental and operational significance. Unless otherwise stated, fluxes cited here are expressed as total per-well emission rates (kg CH_4 d^{-1}); where per-area fluxes (g m^{-2} d^{-1}) are referenced, they represent local surface maxima and are not directly comparable without spatial integration.

Field investigations across several mature petroleum regions show that where leakage occurs, emissions are typically small and often attenuated in the near-surface zone. Detailed site measurements document both minor CH_4–CO_2 co-emission and elevated CO_2 flux without detectable CH_4, consistent with near-complete oxidation of fugitive gas in shallow soils (Cahill et al., 2025, 2023; Le Mer and Roger, 2001). Reported per-well totals are generally modest, i.e. commonly tens to a few hundreds of kilograms per year, though distributions are strongly right-skewed with infrequent high emitters (Lebel et al., 2020; Riddick et al., 2019; Townsend-Small et al., 2016). Broader regional surveys that combine ground and aerial detection reach similar conclusions, with central-tendency per-well rates on the order of 0.1 kg d^{-1} (site- and method-dependent) and only a small fraction producing higher emissions detectable from the air (Pozzobon et al., 2023). Fluxes at individual wells are temporally variable, often modulated by barometric pressure and season, underscoring the need for repeated measurements (Cahill et al., 2025; Forde et al., 2022, O.N. 2019) .

It should be noted that methane detected at the surface in legacy-well studies may originate from both thermogenic (deep, hydrocarbon-associated) sources and shallow biogenic production, and in many cases represents a mixture of the two. Where source attribution has been investigated, higher-magnitude and more persistent emissions are more commonly associated with well-connected, thermogenic leakage pathways, whereas low-level or transient fluxes may reflect shallow biogenic methane or near-surface attenuation of deeper gas (Gianoutsos et al., 2024). From a CCS perspective, the analogue relevance therefore lies primarily in the subset of emissions linked to wellbore-connected leakage, which share governing flow pathways and pressure controls with potential CO_2 migration.

When interpreted collectively, the contemporary record delineates an empirical spectrum of leakage magnitudes rather than discrete categories. Measured fluxes are strongly right-skewed, consistent with an approximately log-normal distribution spanning more than five orders of magnitude, from near-zero to ~10^3 g CH_4 m^{-2} d^{-1} at localized hotspots (i.e., site-specific extremes), indicating that persistent, low-rate seepage dominates over acute failures (Lebel et al., 2020; Riddick et al., 2019; Townsend-Small et al., 2016) (Fig. 2). Most measured fluxes fall within a low-flux domain (< ~0.5 kg CH_4 d^{-1}), representing subtle, even undetectable seepage. A smaller number extend into a moderate range (~0.5–10 kg d^{-1}), detectable at the surface with standard flux methods, and infrequent outliers exceed 10–100 kg d^{-1} or more, reflecting more severe integrity impairment (DiGiulio et al., 2023; Lebel et al., 2020; Townsend-Small et al., 2016). These intervals are indicative, not prescriptive, and illustrate the scale over which observed fluxes vary rather than their likelihood of occurrence.

For GCS containment, this evidence suggests that leakage, if it occurs, will most often manifest as low-rate, localized seepage, challenging to detect but of limited immediate impact. A minority of wells produce higher fluxes that dominate cumulative emissions and warrant targeted monitoring or remediation. Although near-surface microbial oxidation can reduce measured CH_4 fluxes, this does not diminish the analogue's relevance: the same structural pathways and pressure gradients govern CH_4 and CO_2 migration, even if surface expression differs (Bai et al., 2016; Kiran et al., 2017; Vrålstad et al., 2019). Taken together, these observations indicate that magnitude, not occurrence alone, determines whether a leak is consequential.

Analogue studies of methane leakage from legacy wells thus define a coherent picture of well integrity behavior relevant to GCS. They show that integrity loss is distributed across well populations rather than confined to rare, discrete failures; that leakage magnitudes span several orders of magnitude but are most often small; and that both incidence and flux are controlled by the geometry and continuity of leakage pathways and by near-surface modulation. The same physical architecture, i.e. micro-annular flow, partial plug degradation, or compromised cement bonds, governs whether leakage manifests as very low-rate, diffusion-dominated transport or as measurable, advective flow. These controls explain the wide dynamic range observed in analogue data: most leakage pathways impose strong resistance and therefore produce low fluxes, while only a small subset of wells provide sufficiently continuous pathways to sustain higher leakage magnitudes, which are consequently rarer in well populations surveyed with adequate sensitivity. Viewed collectively, the analogue record provides a realistic empirical envelope for the behavior of legacy wells within future GCS projects: leakage is not universal or catastrophic but forms a continuum of low- to moderate-flux behavior shaped by pathway integrity, environmental attenuation, and the sensitivity of monitoring systems.

4. Processes affecting leakage pathways

A wide variety of factors can result in the presence or creation of leakage pathways along wellbores. The most notable leakage pathways in legacy wells are often created through inappropriate well isolation design. Commercial oil and gas drilling began in the mid-1800s and millions of wells have been drilled since (Carter and Flaherty, 2011; Lei et al., 2025). Well drilling and abandonment practices have evolved over the past two centuries alongside changing regulations and advances in drilling technologies, metallurgy, and cement chemistry (King and King, 2013; King and Valencia, 2014). Older wells installed prior to the development of oil and gas regulations may be completely open conduits

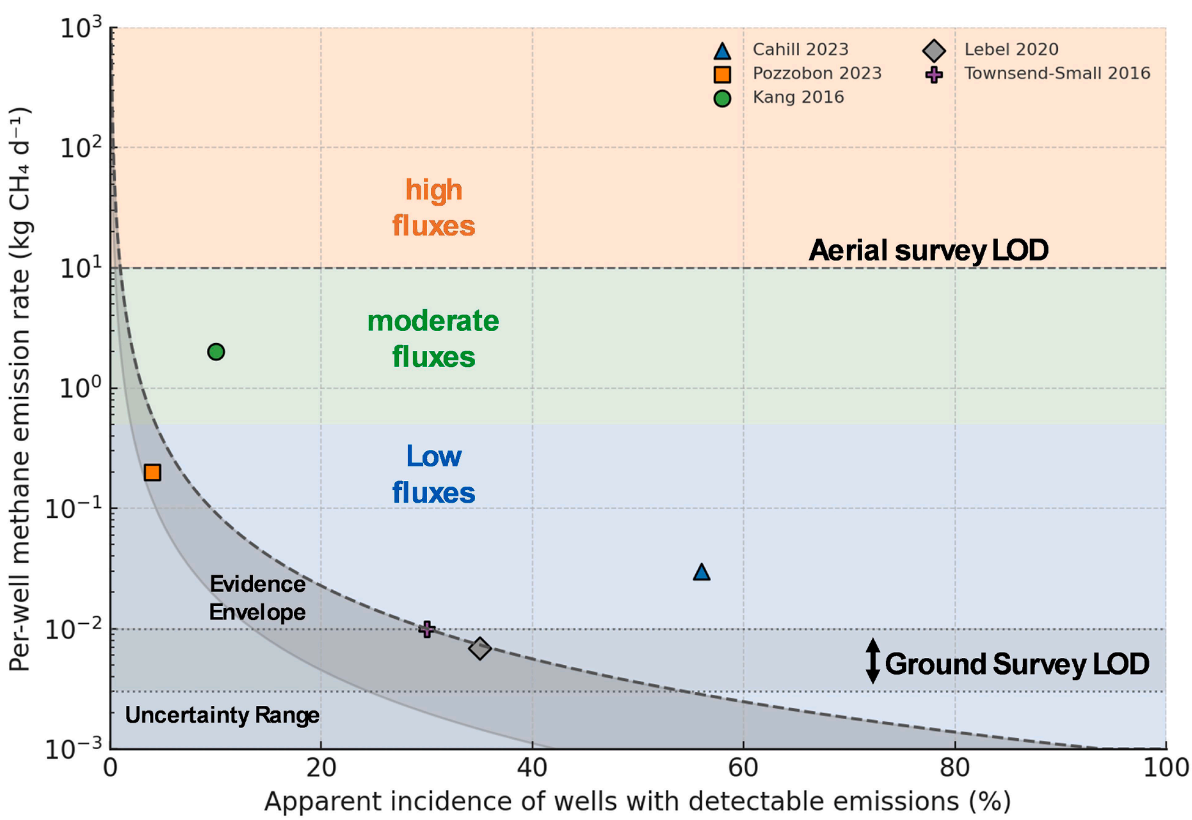

Fig. 2. Empirical and conceptual relationship between methane leakage incidence and magnitude for legacy petroleum wells. Verified methane-emission data from six field studies (Cahill et al., 2023; Kang et al., 2016, 2014; Lebel et al., 2020; Pozzobon et al., 2023; Townsend-Small et al., 2016) illustrate the tendency for higher per-well emission rates to be observed less frequently across surveyed populations. The x-axis shows apparent incidence (% of wells with detectable emissions, conditional on method sensitivity); the y-axis shows per-well emission magnitude (kg CH_4 d^{-1}, log scale). Shaded fields mark typical flux domains and detection thresholds. The grey dashed curve represents a schematic, evidence-informed upper-bound envelope and levels of detection (LOD) for aerial and ground surveys are also noted. Together, these data define realistic limits on leakage frequency, magnitude, and detectability, providing a quantitative analogue for CO_2-storage containment-risk assessment.

as well cementing was not standard until the early 1900s, and early plugging practices consisted of filling wells with readily available debris (King and King 2013).

Modern wells are multi-barrier systems that consist of nested strings of steel casings sealed against each other and the surrounding rock with cement to create hydraulic barriers (Fig. 1). Modern plugging practices are designed to render the well impermeable to unwanted fluid migration by establishing long-term zonal isolation through the installation of multiple mechanical and cement plugs interspersed with sections of drilling mud (King and King, 2013; King and Valencia, 2014). While these advances in well design and plugging substantially improve their sealing ability, fluid migration pathways may still exist along modern wells as they are often not designed or abandoned with future use of the subsurface for GCS in mind. Uncemented annular sections through the storage zone are common where GCS target reservoirs are shallower than hydrocarbon producing zones. The lack of a rock-to-rock barrier in line with the GCS reservoir seal is also common, as plugs are often placed above or below shallower GCS targets (Arbad et al., 2022; Jordan and Wagoner, 2017; Lackey et al., 2024). These practices either leave direct migration pathways for reservoir fluids or make the well more susceptible to their development (Fig. 1).

The existence of well barriers across storage intervals does not guarantee the prevention of well leaks; their ability to isolate fluids can be impaired by incorrect installation, material limitations, and thermomechanical stresses (Barclay et al., 2001; de Lemos, 2024; van Riet et al., 2023; Vrålstad et al., 2019). During cementing, ineffective wellbore fluid displacement may lead to cement contamination, which changes its final properties and impacts bond quality at the cement-formation interface (Agbasimalo and Radonjic, 2014; Katende et al., 2020; Ladva et al., 2005; Opedal et al., 2018, 2014). Cement placement can be further complicated by slumping or flipping of annular fluids (Eslami et al., 2022), potentially leading to channels and incomplete cement coverage (Beltrán-Jiménez et al., 2025; Haut and Crook, 1979; Kolchanov et al., 2018). Intersecting gauge cables or control lines, e.g., if placed on the exterior of the casing, can affect annular cement placement and provide additional pathways. Even under ideal placement conditions, conventional Portland cement may exhibit autogenous shrinkage (Acker, 2004; Brouwers, 2011; Geiker and Knudsen, 1982; Jandhyala et al., 2018; Lura et al., 2003; Wolterbeek et al., 2021a; Ye and Radlińska, 2016), which may result in micro-annulus formation (Corina and Moghadam, 2025; Dusseault et al., 2000; Meng et al., 2021; Moghadam and Loizzo, 2024; Roijmans et al., 2023). Pressure cycling from production, injection, or completion operations, formation movement (i.e., creep), and heating or cooling of the near well region, due to fluid injection or cement cooling, all change the stress state of well cement, which can create radial cracks, flat horizontal cracks (i.e., disking), and microannuli due to debonding (Albawi, 2013; Kuanhai et al., 2020; Lei et al., 2025; Moradi et al., 2020; Roy et al., 2016; Wolterbeek and Hangx, 2023).

Alteration of well materials upon interaction with chemicals encountered in subsurface formations and pore fluids, whether native or introduced during GCS activities, can also result in damage to legacy wells and thereby affect leakage potential. Corrosion of legacy well casings, which typically consist of mild steel, is a major concern for GCS and has recently been reviewed by Choi et al. (2013), Cui et al. (2019), and Wang et al. (2024). Carbonic acid reacts with steel casings to form mixed iron-calcium-carbonates or ferrous iron hydroxides (pH dependent), which can manifest either uniformly across the casing or locally through pitting corrosion (Dalla Vecchia et al., 2020; Wolterbeek et al., 2013). The impact of steel corrosion depends strongly on hydrodynamical conditions. In the case of unprotected steel, e.g., free pipe or otherwise directly exposed casing sections along wellbores, corrosion rates can reach up to several millimeters per year (Han et al., 2011; Seiersten and Kongshaug, 2005; Zhang et al., 2013). Accumulation of mineral scale on the steel surface through corrosion reactions (Supplemental Information (SI) Section S1), can slow down corrosion rates by several orders of magnitude if a sufficiently dense and impermeable layer is formed (Azuma et al., 2013; Choi et al., 2013; Dugstad, 1998; Han et al., 2012; Nešić, 2007). On steel exposed to aqueous fluid, the morphology and porosity of the corrosion scale layer will depend on the relative reaction kinetics of scale formation and iron dissolution. If the rate of the latter outstrips the former, and if there is sufficient free space, scale can become highly porous and less protective (Anwar et al., 2019; Nešić, 2007).

Portland cement is also susceptible to a variety of chemical processes in the subsurface that include: mass-loss due to leaching by percolating water, metal cation-induced cement alteration, sulphate-induced reactions, and carbonation from exposure to CO_2-rich fluids—detailed descriptions of which are provided in SI Section S1 (Bao et al., 2022; Carey, 2013; Taylor, 1997; Warren, 1997). Reactions between Portland cement and CO_2-rich fluids and the process of cement carbonation in the context of GCS have been subject of extensive study (Barlet-Gouedard et al., 2006; Barlet-Gouédard et al., 2009; Bjørge et al., 2019; Carey, 2013; Carroll et al., 2016; Kutchko et al., 2008, 2007; Rimmelé et al., 2008; van Noort et al., 2025a; Zhang and Bachu, 2011). These studies show that carbonation creates a sequence of distinct alteration zones that tend to become wider as reaction advances further into the cement matrix. This alteration has been confirmed in the field through the recovery of CO_2-exposed cement samples at CO_2-EOR sites (Carey et al., 2007; Duguid et al., 2014). Cement carbonation involves (incongruent) dissolution of certain solid phases in the cement and precipitation of others, with carbonates being the main reaction products. While calcium carbonate solubility increases significantly with increasing CO_2 partial pressure (Segnit et al., 1962; Weyl, 1959), dissolution reactions only proceed until carbonates reach chemical equilibrium with CO_2-rich aqueous fluids (Baines and Worden, 2004; Rohmer et al., 2016). Consequently, the balance between dissolution and precipitation during chemical alteration, particularly for the carbonate products, is to a large extent determined by the volume of fluid that can interact with the wellbore materials (Bachu and Bennion, 2009; Liteanu and Spiers, 2011). Here, it is worth noting that dissolution of ionic species requires water, i.e., does not scale directly with the volume of CO_2 injected. Along legacy wells, the "degree of exposure" to aqueous fluids depends strongly on hydrodynamical conditions, including interactions with pore fluids and mineralogy in the reservoir, and ultimately along the cement-steel isolations located within the caprock once carbonated waters reach a legacy well.

In the last decade, researchers studying the ability of legacy well materials to withstand the subsurface conditions created by GCS focused predominantly on the material breakdown of Portland cement. Many efforts considered the interplay between chemical reaction and hydrodynamical factors such as advective transport along discrete pathways in flawed cement. The impact of chemical reactions on the geomechanical properties of well materials and the reactions associated with other chemicals commonly found in CO_2 streams have also been major topics.

4.1. Hydrodynamical factors

The matrix permeability of Portland cement with respect to brine is generally very low, typically below 10 μD (10^{-17} m^2) (Nelson and Guillot, 2006; Taylor, 1997), and the high capillary pressures required to enter its small-sized porosity tend to inhibit displacement of porewater from the cement matrix under downhole conditions (Carey and Lichtner, 2011; Wolterbeek et al., 2024). Good quality cement that forms a tight interface seal with surrounding casings and rock formations can thereby provide an effective barrier to fluid flow, with residual flowrates reduced to the point where transport of chemical species is effectively diffusion-like in character. This severely restricts the fluid renewal rate, as recently demonstrated in core flooding tests imposing very high differential pressures over short cement samples (Lende et al., 2024). Under such diffusion-dominated conditions, the influence of chemical reactions will be limited to the extent over which CO_2-induced alteration (SI Section S1) can advance through the cement matrix (Duguid, 2009; Yuan et al., 2022). While carbonation depth as a function of exposure time varies in lab experiments with pressure, temperature, fluid composition, pH, fluid-to-cement ratio and cement formulation, projected chemical alteration depths typically reach less than one meter in 1000 years (Fig. 3). This is sufficient to potentially affect cement sheaths within reservoir intervals, where radial attack by CO_2-rich fluids is possible. However, the extent is considerably less than the along-hole length of cement sheaths and plugs, which typically cover tens to hundreds of meters. For this reason, chemical alteration progression through the cement matrix is widely viewed as insufficient to pose a threat to system-scale integrity of well isolations along caprock (Carey, 2013; Carroll et al., 2016; Duguid, 2009; Wolterbeek et al., 2016b). Recent lab studies expanded our understanding by investigating combined effects from concurrent sulphate attack, ion-exchange reactions, and reactions with impurities (see Section 4.3; SI Section S1) but none of these factors fundamentally change the reactive-diffusive processes that govern reaction front progression in good cement.

Not all cement isolations form tight interfaces, as evidenced by field studies where chemical alteration has been observed to concentrate along casing-cement-rock interfaces and has reached up to 60 m above the reservoir (Carey et al., 2007; Crow et al., 2010). Indeed, a decade ago, it had become clear that extensive leaching or chemical alteration could become a concern if the low-permeability cement matrix is bypassed via defects (Carey, 2013; Carroll et al., 2017). Wellbore isolations can suffer from preexisting defects such as fractures in the cement, or debonding along interfaces with the casings or surrounding rock formations. If sufficiently interconnected, defects may provide pathways for larger volumes of CO_2-rich fluid to penetrate and interact chemically with wellbore materials. Under advective flow conditions, there is potential for a continuous supply of fresh reactants (e.g., carbonic acid; Reaction SR1 in SI) while calcium ions and other species liberated via (incongruent) dissolution of cement phases (e.g., Reactions SR3-SR4 in SI) may be transported downstream or even removed entirely with the flowing fluid. Precipitated carbonates (Reaction SR5 in SI) might eventually redissolve (reverse Reaction SR5 in SI) if the cement is exposed to continued inflow of large volumes of carbonate-undersaturated brine.

Numerous experimental studies have investigated how flowing CO_2-rich brine impacts the permeability evolution of open fractures in cement (Abdoulghafour et al., 2016, 2013; Cao et al., 2015; Chavez Panduro et al., 2020; Huerta et al., 2016; Luquot et al., 2013; Miao et al., 2022; Nguyen et al., 2020; Rod et al., 2020). In many samples, fracture permeability was found to decrease due to clogging via carbonate precipitation, while others showed stable or even increasing flow over time. Parallel advances in coupled numerical modelling of the underlying dissolution-precipitation reactions and diffusive-advective transport processes have shown that the conditions for "self-sealing" versus "non-sealing" reactive flow of CO_2-rich fluids in cement fractures can be captured aptly in terms of the initial a) aperture of the defect and b) residence time of the fluid (Brunet et al., 2016; Cao et al., 2015; Guthrie et al., 2018; Iyer et al., 2017). Qualitatively, narrower defects are easier to seal and increasing the interaction time allows for buildup of higher solute concentrations, enabling precipitation, whereas short residence times do not, maintaining carbonate-undersaturated conditions in the fluid.

Carey et al. (2010) were some of the first to examine CO_2 reactive flow through debonded cement-steel interfaces. Inserting a freshly polished low-carbon steel rod into a pre-slotted cement sample, they found the steel was far more reactive than the cement, observing extensive corrosion and precipitation of iron carbonates. By contrast, corrosion scale formation played a subsidiary role compared to calcium carbonate precipitation in more recent experiments of Wolterbeek et al. (2016b, 2019). Wolterbeek et al. (2016b) used samples consisting of 1–6 m-long cemented steel tubes, in which the cement was cured together with the steel for over one year, preconditioning the steel surface, likely reducing its reactivity (Choi et al., 2013). Despite less prominent corrosion reactions, permeability of the cemented steel tubes was found to decrease

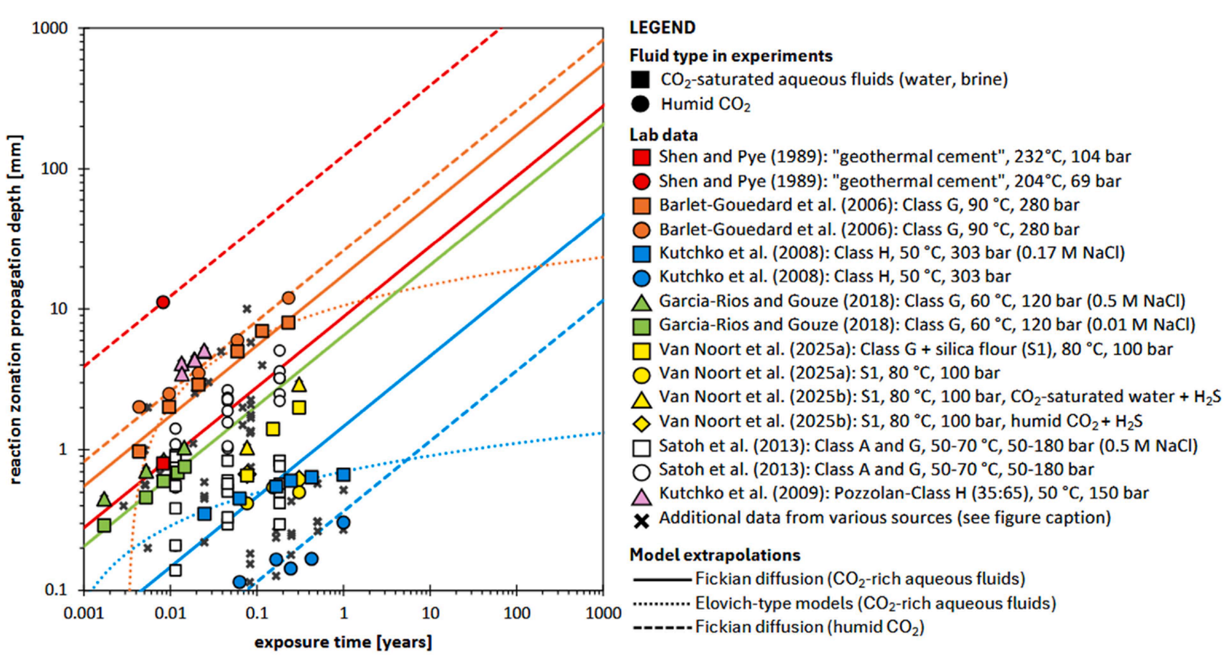

Fig. 3. Plot of CO_2-induced reaction front progression in Portland cement matrix [mm] as a function of exposure time [years] as observed in lab experiments (see legend for cement type and test conditions). Highlighted studies are selected to showcase longer-duration tests and to cover the investigated range in conditions. Black crosses represent data from additional studies, but these have not been separated to maintain legibility of the graph (Barlet-Gouedard et al., 2006; Barlet--Gouédard et al., 2009; Bruckdorfer, 1986; Duguid, 2009; Garcia-Rios and Gouze, 2018; Giannoukos et al., 2014; Gu et al., 2017; Kutchko et al., 2008, 2009; Rimmelé et al., 2008; Satoh et al., 2013; Shen and Pye, 1989; Takla et al., 2010; van Noort et al., 2025b; van Noort et al., 2025a; Wolterbeek et al., 2016b). Experimental data are extrapolated to longer exposure times using least-squares best fits assuming Fickian diffusion (solid and dashed lines) and Elovich-type adsorption models (dotted lines).

by up to four orders of magnitude upon exposure to CO_2-rich brine. Microstructural observations revealed extensive calcium carbonate precipitation in the debonded interfaces. In general, the lab measurements made on debonded cement-steel interfaces can be explained fairly well using the critical residence time concepts originally developed for fractured cement (Wolterbeek et al., 2024).

Cement-rock interfaces are studied less extensively, possibly because this type of contact is variable in nature and comparatively difficult to simulate accurately in lab experiments. The initial condition of the interface is highly dependent on factors like surface roughness of the borehole or residual mud contamination (Agbasimalo and Radonjic, 2014; Opedal et al., 2019, 2014). Significant differences in how reactive transport manifests can also be expected between cement-caprock interfaces, where the rock side has a very low permeability, limiting ingress of fluids to pathways provided by defects, and cement-reservoir rock interfaces, where high permeability of the rock-side enables direct exposure to CO_2-rich fluids (Duguid et al., 2011; Jahanbakhsh et al., 2021; Shi et al., 2025; Tremosa et al., 2017). An example of the latter category includes Cao et al. (2013), who performed CO_2 flow-through tests on a composite cement-Berea sandstone core with a continuous, large initial gap in the cement. They found permeability increased due to extensive leaching.

Focusing on cement-caprock interfaces, which will be more critical to zonal isolation integrity along legacy wells, Newell and Carey (2012) performed core-flooding experiments using CO_2-brine at 10 MPa and 60°C on a cement-siltstone composite core containing a simulated high-permeability damage zone. While post-test microscopy revealed leaching, erosion, and the development of defect-parallel alteration zones within the cement half, the effective permeability of the composite core was found to have reduced from 200 mD to 35 mD. The authors attributed this to migration and reprecipitation of alteration products derived from the cement within the simulated damage zone. Jung et al. (2014) exposed cement-basalt caprock cores with fractures to CO_2-brine at 10 MPa and 50°C, albeit under static fluid conditions. Based on X-ray microtomography of the fracture network before and after exposure, combined with computational fluid dynamics modelling, Jung et al. (2014) inferred that reactions resulted in precipitation and disconnection of fractures. More recently, Fernandez-Rojo et al. (2021) performed flow-through tests on composite cement-limestone, cement-marl, and cement-sandstone cores containing interfacial defects. Their results showed marked alteration and increased porosity. Based on the reported initial defect aperture (>300 μm) and short residence time (<300 s), these findings are consistent with model predictions based on fractured cement systems (Fig. 4).

Various findings from lab experiments involving exposure of fractured cement (Abdoulghafour et al., 2016, 2013; Cao et al., 2015; Huerta et al., 2016; Luquot et al., 2013; Miao et al., 2022; Nguyen et al., 2020), cement-steel interfaces (Wolterbeek et al., 2016b, 2019), and cement-rock interfaces (Fernandez-Rojo et al., 2021; Mason et al., 2013; Walsh et al., 2014) to flowing CO_2-rich brine can be captured in terms of initial defect aperture and fluid residence time (Brunet et al., 2016; Iyer et al., 2017)(Fig. 4). Experiments that showed a continuing decrease in permeability down to impermeable values (shown in green) are located inside the self-sealing domain delineated by the Brunet et al. (2016) model, while lab samples which displayed no tendency for permeability reduction (orange) plot largely below the critical residence time

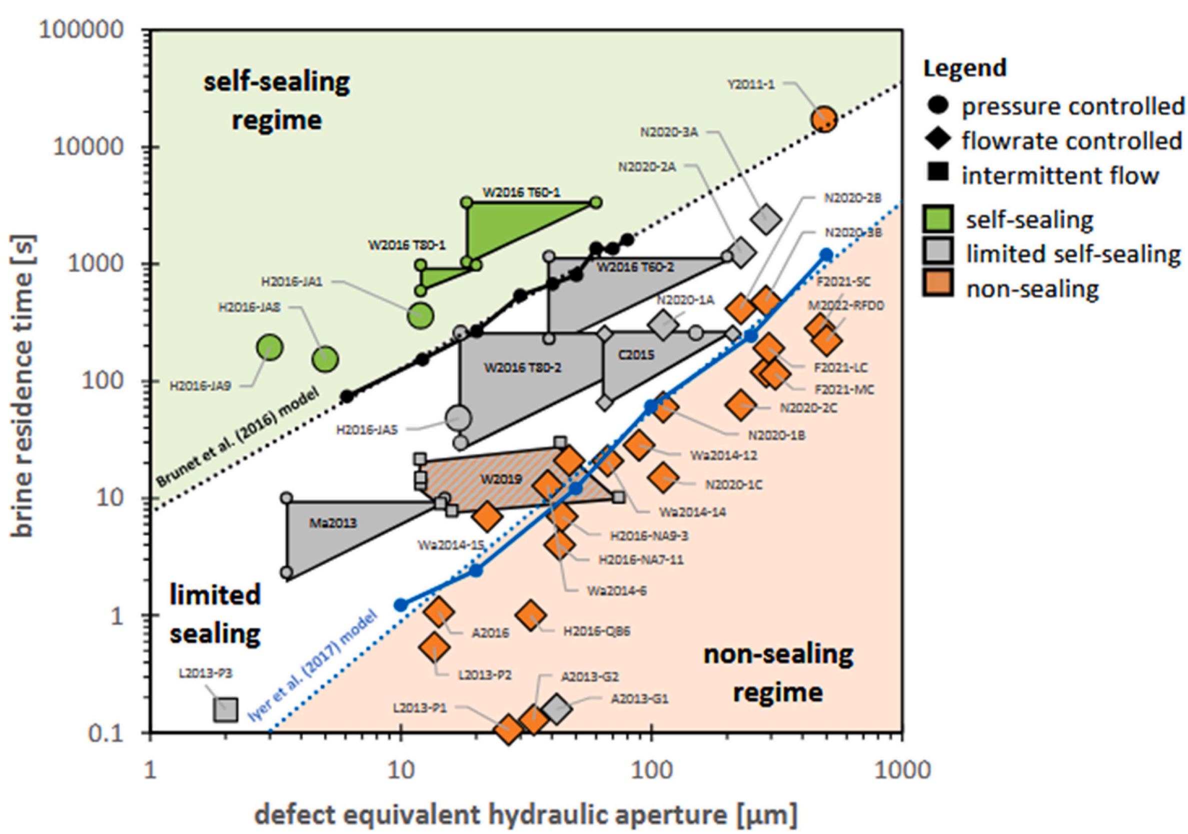

Fig. 4. Self-sealing and non-sealing regimes for reactive transport of CO_2-rich brines in cement defects, plotted in residence time versus hydraulic aperture space (modified after Wolterbeek et al., 2024). Graph shows experimental data for cement fractures, cement-casing interfaces and cement-rock interfaces, together with numerical model predictions of Brunet et al., 2016 and Iyer et al., 2017. Circles, diamonds, and squares represent lab tests conducted under pressure-controlled, flowrate-controlled, and intermittent flow conditions, respectively. Labels include codes per study, appended by experiment names as in the original publications: A2016, A2013 = Abdoulghafour et al. (2016, 2013); C2015 = Cao et al. (2015); F2021 = Fernandez-Rojo et al. (2021); H2016 = Huerta et al. (2016); L2013 = Luquot et al. (2013); Ma2013 = Mason et al. (2013); M2022 = Miao et al. (2022); N2020 = Nguyen et al. (2020); Wa2014 = Walsh et al. (2014); W2019, W2016 = Wolterbeek et al. (2019, 2016b); Y2011 = Yalcinkaya et al. (2011).

obtained by Iyer et al. (2017). Experiments marked as "limited sealing" (grey) generally showed some level of permeability reduction (e.g., 1–2 orders of magnitude) but did not become fully impermeable on the timescale of the lab tests. Combined, the experimental and modelling data provide confidence that small defects (e.g., apertures of 1–100 μm wide) possess some definite capacity to self-seal against ingress of CO_2-rich brine, provided that the wellbore isolation has sufficient length for residence times to exceed critical values. Note the residence time will also depend on the driving force for flow, which may initially be very limited in the case of storage in depleted hydrocarbon reservoirs, in particular. Larger-scale defects such as free-water channels or mud channels (e.g., apertures of >500 μm wide) are much less likely to self-seal through carbonate precipitation. However, it is worth noting that, given the potential magnitude of seepage fluxes associated with defects of this size, taking some form of remedial action to fix the well will likely be warranted, regardless of chemical alteration effects.

While the "critical residence time"-concept has proven a useful metric in predicting whether reactive flow of CO_2-rich fluids along cement defects in lab experiments will be self-sealing or non-sealing (Brunet et al., 2016; Iyer et al., 2017; Nguyen et al., 2020), application of this concept in numerical models and translation to field conditions is far from trivial (Guthrie et al., 2018; Wolterbeek et al., 2019). Residence time is an extensive property, defined at the system scale (e.g., sample size in lab experiments). While one could also define residence times for individual "cells" in a discretized numerical model, the composition of the influent fluid phase will then be different for subsequent cells, rendering what would be the "critical residence time" at the scale of such individual cells undefined. Clearly, how to effectively upscale the detailed reactive transport models to wellbore dimensions remains one of the outstanding research questions for the coming decade.

The geometry of the leakage pathway is another factor that potentially impacts the self-sealing behavior of cements, which is relevant considering the non-uniform character of microannuli (Moghadam et al., 2021). Flow in rough defects will include inertial effects and system-scale residence time concepts may become challenging to apply if most of the fluid flow occurs via a limited number of preferential pathways. In a numerical modelling study of meter-scale cement-casing sections, Wolterbeek and Raoof (2018) investigated different defect geometries with equivalent system scale-averaged transport properties. They found that initial defect nonuniformity has a profound impact on self-sealing and permeability evolution. Where Wolterbeek and Raoof (2018) only considered non-uniformity in the along-flow direction, Tafen et al. (2023) examined a two-dimensional fracture geometry with surface roughness. Their simulations show that narrower initial aperture domains self-seal rapidly, while wider domains can remain open considerably longer. The authors emphasize they only investigated a constant injection rate scenario, which by definition prevents fully self-sealing flow conditions from occurring (Tafen et al., 2023). Hence, applicability of the critical residence time concept to non-uniform aperture defects remains to be confirmed and is an area of active research (Iyer and Smith, 2024).

Nearly all reactive transport experiments performed to date involved exposure of cement samples to flowing CO_2-rich aqueous fluids (i.e., water or brine with dissolved CO_2). While water-based flows may be representative for specific cases, due to buoyancy forces it is likely that seepage along many legacy wells will rather involve flow of predominantly humid CO_2 (i.e., CO_2 in its gaseous, liquid or supercritical state with dissolved water) or possibly multiphase flow conditions (Emami-Meybodi et al., 2015; Feng et al., 2017; Kjøller et al., 2016). Such scenarios involve capillary effects, buoyancy-driven flows, transient flow paths, and multiphase flow effects (Anwar et al., 2024; Beltrán-Jiménez et al., 2025; Lima et al., 2025), which can profoundly impact reactive transport processes. Humid CO_2 and CO_2-rich brine have drastically different properties, e.g., in terms of mineral solubility, and are known to produce distinct alterations in cement batch reaction tests (Kutchko et al., 2011; Wolterbeek et al., 2013). Nearly all mineral dissolution-precipitation reactions occur in aqueous fluid. Flow of a non-aqueous, CO_2-dominated fluid instead of carbonated brine will significantly reduce the mobility of water-soluble species, which in turn will impact the distribution and extent of dissolution-precipitation reactions in both defects and the cement matrix. This may be beneficial because, if there is limited water in which carbonates can dissolve, then excessive leaching becomes much less of a concern. Conversely, reduced reactivity can also lessen the effectiveness of self-sealing mechanisms (Wolterbeek and Hangx, 2021). Modelling by Iyer et al. (2018) found that reduction in the reactive surface area associated with lower water-saturation could cause self-sealing processes to slow down or even fail to achieve an impermeable state. Recently, Wolterbeek et al. (2024) reported the first reactive flow-through experiments using humid CO_2 as flowing medium. Their samples consisted of cemented steel pipes containing 2–20 μm-wide interfacial microannuli. While exposure to humid CO_2 produced substantial reductions in effective permeability, the overall extent of reaction and amount of carbonate precipitation were limited compared to earlier experiments using CO_2-rich brine. These findings underscore the need for more realistic simulation of real CO_2 phases and multiphase flow dynamics in laboratory experiments (Abid et al., 2024).

4.2. Geomechanical factors

Geomechanical factors play a major role in the creation of defects that may provide pathways for flow. In legacy wells, pre-existing defects can be sustained from temperature changes (Albawi, 2013; Li et al., 2025; Moradi et al., 2020; Roy et al., 2018; Wolterbeek and Hangx, 2023) or pressure loads experienced during well operations (Kuanhai et al., 2020; Lecampion et al., 2013; Meng et al., 2021; Nygaard et al., 2014). Once the CO_2-plume reaches a legacy well, interplay with chemical alteration can induce changes in the mechanical properties of wellbore materials (Hangx et al., 2016; Kuo et al., 2017). This may affect the wellbore response to thermo-geomechanical loads in two ways: (i) mechanical weakening of intact seals may change their susceptibility to damage development and (ii) mechanical deformation can impact the permeability evolution of existing defects. Both could, in turn, change the hydrodynamical conditions prevailing along the wellbore (Section 4.10).

Uniaxial and triaxial compression tests on cement reacted with CO_2-rich fluids show variable results. Most studies report mechanical weakening (Barría et al., 2022; Condor and Asghari, 2009; Kuo et al., 2017; Neves et al., 2024), while some observe increased strength in carbonated samples (Liteanu et al., 2009; Omosebi et al., 2017; Takla et al., 2010). The diverging results may partly be due to differences in the volume of fluid used in exposure tests, with weakening occurring preferentially in experiments on extensively leached samples, while samples reacted with humid CO_2 or limited CO_2-brine sometimes show strengthening. Variability is also related to development of zonation. Upon reaction with CO_2, cement can transform from an homogeneous, isotropic material into a highly heterogeneous and anisotropic one, which complicates mechanical characterization by conventional compressive strength testing methods (Chang and Chen, 2005). Several studies therefore adopted methods that can be applied to individual alteration zones in the CO_2-reacted cement, such as scratch tests (Hangx et al., 2016) or micro-indentation tests (Kutchko et al., 2009; Li et al., 2015; Mason et al., 2013; Walsh et al., 2014). Such measurements show reaction can locally plug pores and can even create a stiff crust in carbonate-enriched zones (see zones Z2 and Z3 in SI), but zones dominated by loss of portlandite and decalcification of calcium silicate hydrate phases (see zones Z1 and Z4 in SI) have lower stiffness and hardness than unaltered cement. Extensive dissolution can cause cement to lose cohesion and strength, especially just behind the carbonated rim, i.e., at the contact between the carbonated and portlandite-depleted zone (see Z3 and Z4 in SI) (Barría et al., 2022; Kuo et al., 2017; Li et al., 2025).

Mechanical strength values obtained from scratch and hardness tests vary widely, even within a single reaction zone of a single sample (Hangx et al., 2016; Huet et al., 2010; Kutchko et al., 2009; Mason et al., 2013). Most studies show, despite carbonate precipitation, a significant overall reduction in stiffness (Young's Modulus) and Unconfined Compressive Strength (UCS) of cement when exposed to CO_2-rich fluids (Barría et al., 2022; Kuo et al., 2017; Li et al., 2015; Neves et al., 2024). Key factors that influence the severity include temperature, fluid type (humid CO_2 vs. CO_2-rich brine), exposure duration, and cement formulation. Barría et al. (2022) noted that, although outer layers densify, overall bulk strength did not improve in their CO_2-reacted samples, because the precipitated carbonates were poorly bonded and the calcium silicate hydrate (CSH) "backbone" was degraded. An interesting chemical-mechanical lab study is presented by Gu et al. (2017), who investigated the impact of tensile stress on cement alteration. They subjected Class G cement samples to simultaneous CO_2 exposure and tensile loading (25–75% of tensile strength) to simulate cement under hoop stress in a wellbore. The results showed that samples under higher tension (50–75%) developed more microcracks, which let CO_2 penetrate much faster than in unstressed cement samples. Consequently, the stressed samples failed (lost integrity) much earlier than ones without external load. Exposure to CO_2-saturated brine caused failure sooner than humid CO_2, likely because the aqueous phase facilitates dissolution and transport out of the cracks more effectively. These findings indicate that the combination of chemical and tensile stress may cause accelerated weakening in wellbore isolations.

While lab experiments demonstrate chemical reaction can significantly alter the mechanical properties of cement, it is not trivial to evaluate the impact of these changes on integrity at the well isolation scale. Whether defects lead to zonal isolation loss and integrity failure depends on their extent and interconnectedness. There is a lack of standardization in reporting the changes in mechanical properties of cement. Hardness and UCS measurements are the most reported parameters. These measurements are relatively cheap and fast. However, UCS and hardness are of limited usefulness in geomechanical models. Typically, downhole cement is under confined conditions (Lima et al., 2022; Liteanu et al., 2009; Neves et al., 2024; Wolterbeek et al., 2016a). Parameters such as the Young's Modulus, Poisson's ratio, tensile strength, and plasticity parameters (such as the modified cam-clay model) are more representative of actual cement behavior downhole (Bois et al., 2012; Thiercelin et al., 1998). Shear failure in cement under confinement is typically a ductile response which may not cause fractures (Bois et al., 2011; Lima et al., 2022; Moghadam and Loizzo, 2024; Wolterbeek et al., 2016a). Disking cracks do not lead to vertical fluid migration due to their geometry. Therefore, it is unclear whether a reduction in UCS due to chemical reactions leads to detrimental effects in the cement under downhole conditions if the confined strength holds. Recent near-well mechanical modelling studies conclude that a cement sheath with lower Young's modulus (softer, more compliant) forms smaller micro-annuli when pressure or temperature drops, compared to a stiff cement (Bai et al., 2015; Moghadam and Loizzo, 2024). In essence, a ductile cement can deform with the steel casing, maintaining contact, whereas a brittle cement tends to debond to form a microannulus. A reduction in UCS and Young's Modulus may increase cement's ductility, which may improve its performance against microannuli (Lavrov, 2018). By contrast, a reduction in tensile strength may cause issues if tensile loads are expected in the cement sheath. Tensile cracking of cement has been shown to lead to flow in smaller lab-scale samples (Boukhelifa et al., 2005). However, in large-scale tests (one to two meter length-scale), the tensile cracks do not appear to form a continuous leakage pathway (Corina and Moghadam, 2024; Therond et al., 2017). Therefore, the interplay between chemical reactions and geomechanical factors remains complex and unclear. Additional exposure experiments on samples with representative geometry, under a realistic stress state, temperature, and CO_2 concentration would be beneficial to improve our understanding of the interplay between geomechanics and chemistry, particularly with respect to changes in susceptibility to defect formation. As discussed in Section 4.1, defects can drastically change hydrodynamic conditions along the well. These intimately coupled reaction-transport-mechanical (RTM) processes have attracted increasing research interest over the last decade and will undoubtedly continue to do so in the next.

The impact of mechanical processes on CO_2-reactive transport in existing defects has also been studied in the last decade. Chemical alteration is generally accompanied by a change in porosity, which can increase if dissolution dominates, or decrease due to precipitation of solids. Without any mechanical deformation, dissolution-controlled reaction (i.e., "non-sealing" regime in Fig. 4) and associated increases in porosity or fracture volume will likely contribute to elevated permeability (e.g., Cao et al., 2013). Under confining pressure, however, reaction-induced weakening of the solid asperities that maintain contact and support the open fracture, can result in lowered transmissivity via mechanical defect aperture closure, potentially even if residence times would be too short to facilitate defect clogging via carbonate precipitation (Rhino et al., 2021; Walsh et al., 2014). Wolterbeek et al. (2016a) considered reaction-induced changes in the strength of already fractured cement, specifically to evaluate whether mechanical weakening could facilitate dynamic reactivation, growth and (re)opening of pathways. They performed triaxial compression tests on cement. Samples that failed on localized shear fractures were subsequently reacted with CO_2-saturated water and then subjected to a second triaxial test to assess changes in mechanical properties. They found that, once shear-fractures formed, subsequent reaction with CO_2 did not produce further mechanical weakening. Instead, after six weeks of reaction, they observed up to 83% cohesion recovery and 15–40% higher frictional strength in the post-failure regime, which Wolterbeek et al. (2016a) attributed to carbonate precipitation within the fractures.

4.3. CO_2 source stream impurities

Removal of low-level concentrations of impurities such as hydrogen sulfide (H_2S), sulfur oxides (SO_x), nitrogen oxides (NO_x), or hydrogen (H_2) from the CO_2 stream is technically complex and operationally expensive, potentially affecting GCS project economics. Even if the concentrations of impurities in the source stream are kept low, once injected into a geological reservoir, higher local concentrations may still develop due to preferential partitioning of impurities like H_2S, SO_x and NO_x into the formation water (van Noort et al., 2025a). Researchers thus began investigating the impact of CO_2 stream impurities on cement alteration, among which the effect of H_2S is probably the best studied. Compared to pure CO_2-brine, exposure of cement to brine saturated with CO_2 and H_2S introduces a number of additional reactions, mainly involving oxidation–reduction and sulfidation of minor cement phases (Kutchko et al., 2011; SI Section S1). One of the additional products is secondary ettringite (Kutchko et al., 2011; Zhang et al., 2014). Ettringite formation involves a net increase in solid volume, which could potentially reduce porosity, but the process can also generate crystallization stress in the cement matrix (Flatt and Scherer, 2008). Excessive ettringite formation can lead to cracking, hence the moniker "sulphate attack" in concrete engineering contexts (Yin et al., 2023; Zhang et al., 2024). On the other hand, limited ettringite-formation can be beneficial to wellbore cement, as evidenced by its use as an expansion additive to mitigate autogenous shrinkage (Beirute, 1976; Bour et al., 1988; Klein, 1958; Souza et al., 2023). Further research is needed to better understand how ettringite formation manifests under the confined conditions typically presented by downhole wellbore environments. Lab tests to date involved cement samples submerged in sulphate-bearing aqueous solutions, which were unconstrained and free to expand (Gu et al., 2019; Jabbour et al., 2022; Pavoine et al., 2012). Under these circumstances, cracking damage can initiate as soon as crystallization stresses exceed the (generally low) tensile strength of the cement (Gu et al., 2022; Sarkar et al., 2010). By contrast, such free expansion is strongly inhibited in well isolations, where the cement will be restricted by the casing and surrounding rock formations. For other crystallization stress-generating reactions, like magnesium oxide (MgO) hydration, lab experiments showed potential for overexpansion and cracking reduces markedly under confinement (Wolterbeek et al., 2021a).

Concerning the impact on cement carbonation processes, Omosobi et al. (2017) found presence of H_2S reduces carbonation front propagation and helps maintain mechanical integrity, while enhancing permeability. Peng et al. (2022) reported a reduction in mechanical strength in the carbonated rim. More recently, van Noort et al., 2025a found presence of H_2S during exposure to CO_2-saturated water enhanced alteration depths by up to one and a half times, while reducing carbonate precipitation. Neves et al. (2024) report lower mechanical strength and reduced stiffness (decrease in elastic moduli). In general, however, the additional reactions in the presence of H_2S seem to have a relatively minor impact compared to the overall carbonation process (Jacquemet et al., 2012; Kutchko et al., 2011; Um et al., 2017).

To the authors' knowledge, the influence of NO_x impurities on cement carbonation has received little attention to date. Pearce et al. (2018) studied interactions with rock forming minerals and concluded that NO_x and SO_x concentrations below 100 parts per million do not significantly impact pH, with reaction still controlled by carbonate buffering. While still to be confirmed in experiments on cement, this suggests limited impact on carbonates, i.e., the main reaction products of CO_2-induced cement alteration.

5. Leakage risk management

Legacy well leakage is typically interpreted and managed through the lens of risk (Dean and Tucker, 2017; International Association of Oil & Gas Producers, 2023; IPCC, 2005; Thomas et al., 2022). Risk consists of three parts: (i) a scenario of concern such as leakage, (ii) the probability of the scenario occurring, and (iii) the consequence of the occurrence (Kaplan and Garrick, 1981). At the highest level, leakage of injected CO_2, brine, or hydrocarbons is the primary scenario of concern associated with legacy wells. Leaking reservoir fluids can potentially have negative impacts on human health and safety, the environment, permit approvals, company public perception, and project finances (Bielicki et al., 2015, J.M. 2014; Boyd, 2016; Carroll et al., 2014; Deng et al., 2017). When broken down, there are multiple leakage scenarios that range from the slow seepage of reservoir fluids through a cement defect to a rapid release of fluids through a failed well. These leakage scenarios each have their own associated probability and impact and are typically treated separately in risk assessments.

Managing the risks associated with legacy wells is essential to the safety and success of GCS. Risk management is a comprehensive process that includes identifying, assessing, and mitigating risks (Aven, 2016). The SRCCS outlined the basic elements of legacy well risk management: locating wells, characterizing well integrity, assessing leakage risks, and mitigating risks through well intervention, re-use, and monitoring (IPCC, 2005). Active and approved GCS projects with legacy wells have implemented a variety of different risk management strategies (Table 2). Recent studies have proposed workflows that align combinations of the risk management elements identified in the SRCCS with GCS project development phases and integrate risk assessment with economic and regulatory constraints to determine the need and feasibility of mitigative actions (Patil et al. 2025; 2024; Torsæter et al. 2024). As a project progresses through a legacy well risk management workflow, the total well population considered narrows, and more effort is put into risk assessment. Once the risks associated with individual wells are constrained, they are weighed against the cost and risk of mitigative actions. This decision space is informed by local regulations, which set the threshold for acceptable leakage risk, as well as project economics and operator risk tolerance, which determines the threshold for the cost and risk mitigative actions (Fig. 5). Ultimately, a decision must be made to avoid, intervene, leave, or reuse each well (Fig. 6). Measurement, monitoring, and verification plans collect data that provide feedback on these decisions during project operation, which is valuable for determining the need of future mitigative actions. While commonalities can be found in legacy well risk management processes across projects, their implementation varies due to site-specific considerations, operator preferences, and local regulations. We review the research progress made in the past decade on leakage risk management for legacy wells. The review is organized by the major elements of risk management (Fig. 5).

5.1. Regulatory requirements

Requirements for legacy well risk assessment and risk management

Table 2
Summary of legacy well risk management practices implemented at the Moomba CCS project (Santos, 2024) and proposed for the Porthos (Neele et al., 2020) and Brown Pelican (CCUS Map, 2025) projects.

	Moomba CCS, Australia	Porthos, The Netherlands	Brown Pelican, U.S.
Operator	Santos, Beach Energy	TAQA	Oxy Low Carbon Ventures
Onshore or Offshore	Onshore	Offshore	Onshore
Location	Strzelecki and Marabooka Fields; Cooper Basin, South Australia	P-18 gas field (4 and 2); North Sea, South Holland	Lower San Andreas, Midland Basin, Texas
Reservoir Type	Depleted Gas Field	Depleted Gas Field	Saline Aquifer
Project Start	2024	2026 (plan)	T.B.D.
Injection Wells	5	4	3
Injection Rate, Mtpa	1.7	2.5	0.7
Legacy Wells	37*	4	3
Risk Assessment Method	Semi-quantitative (Santos Management System)	Qualitative and Quantitative	Qualitative and Quantitative
Risks Identified	Poor cement, cement degradation, casing corrosion, tubing or packer failure	Surface casing corrosion; Production packer corrosion; Joule-Thomson & evaporative cooling creating microannuli	Lack of proper isolation; cement degradation by carbonic acid; mechanical barrier failure; microannuli
Risk Mitigation	Re-use (11 for monitoring), abandonment (number unclear), monitoring	Workover and re-use (4 for injection)	Re-enter and re-plug (3); brine extraction to manage injection zone pressure
Well Monitoring Plan	Well integrity assessment through annular, cement, and casing/tubing monitoring. Above zone monitoring.	Well integrity monitoring; seabed monitoring	Above zone monitoring; geophysical monitoring
Well Monitoring Methods	Ongoing: acoustic and ultrasonic cement bond logs; mechanical caliper logs	Annular pressure monitoring; logging; annular liquid analysis	Nothing specific to the re-plugged legacy wells

* Estimated from maps and permitting documents; total number may be higher.

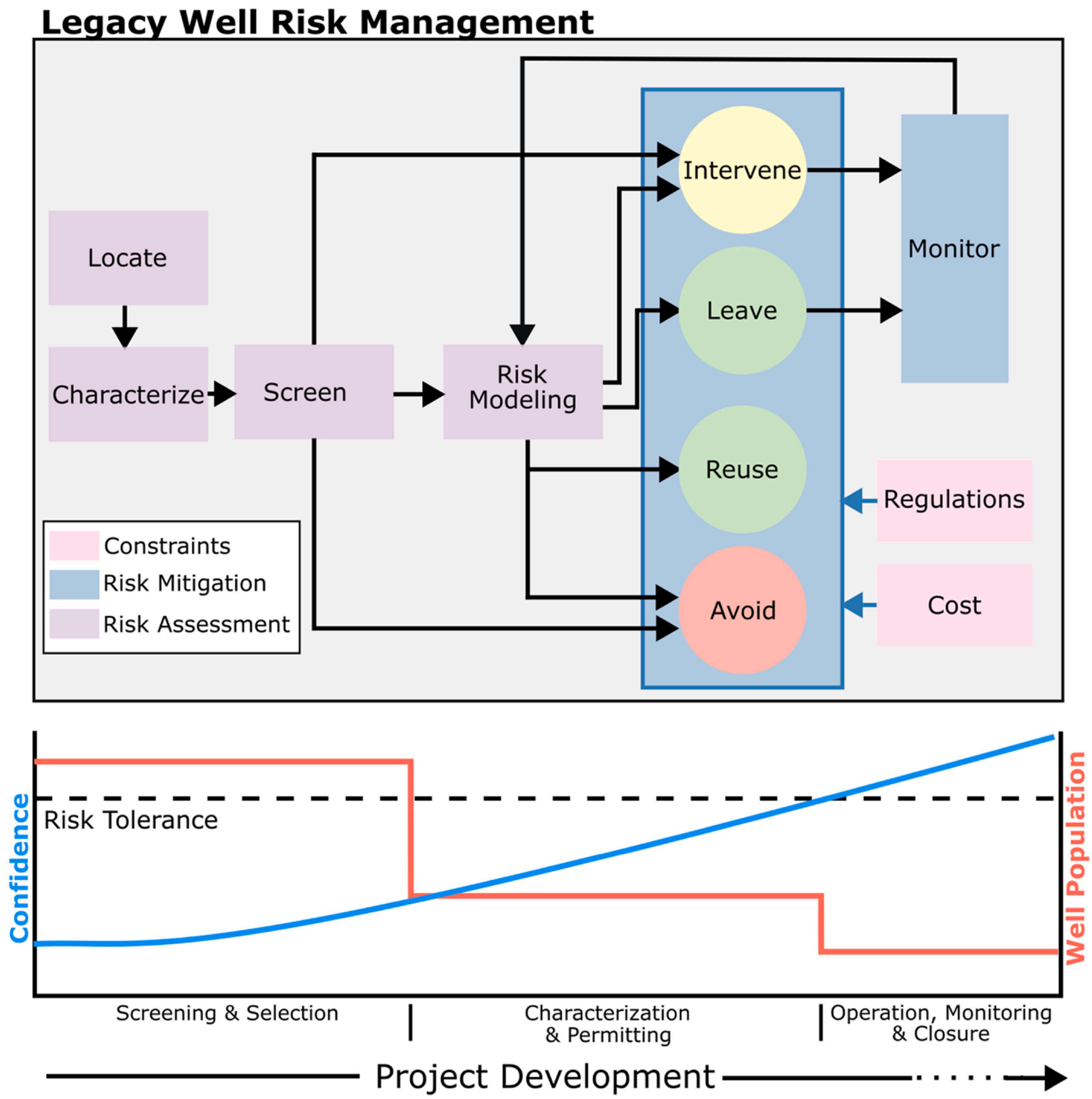

Fig. 5. Example legacy well risk management workflow based on proposed workflows in Patil et al. (2025) and Torsæter et al. (2024) (top). The well population and risk assessment confidence throughout the project development timeline are also shown (bottom).

vary by jurisdiction. In Europe, the European Union's (EU) CCS Directive (2009/31/EC) and the United Kingdom's (UK) Energy Act (SI 2010/2221) provide foundational regulatory frameworks for GCS, which are supported by international standards (ISO 27,914:2017 Clause 6 and DNV-RP-J203 Section 6). North American GCS regulations are a mixture of federal and state or provincial laws. In the U.S., the Environmental Protection Agency (US EPA) regulates GCS through the Underground Injection Control Program's Class VI Rule, a mandate of the Safe Drinking Water Act (U.S. EPA, 1974). U.S. states with primacy (North Dakota, Wyoming, Louisiana, and West Virginia) regulate GCS in their own jurisdictions in a manner that meets the federal Class VI requirements. In Canada, Alberta has established comprehensive GCS regulations through the Mines and Minerals Act (CST 56/2016) detailed in Directive 065 (Alberta Energy Regulator, 2024). Australian regulations for offshore GCS are established by the Offshore Petroleum and Greenhouse Gas Storage Act, the Environment Protection (Sea Dumping) Act, and the Environment Protection and Biodiversity Conservation Act and onshore regulations are established by state or territory legislation (Commonwealth of Australia, 2023).

The EU, UK, Australia, and Alberta, take similar but legally distinct approaches to legacy well risk regulation. All four jurisdictions require formal risk assessments but use different methodologies for risk management. The EU and Australia require the mitigation of legacy well risks until they are as low as reasonably practicable (ALARP) (Commonwealth of Australia, 2023; European Commission, 2024). ALARP is a risk reduction principle commonly applied in health and safety law and industrial operational standards that requires the reduction of risks to a level where further mitigation would involve costs, time, or effort that are grossly disproportionate to the benefits gained.

In Alberta, Directive 065 (D65) adopts a risk-based framework for legacy wells that emphasizes risk tolerability and acceptability rather than explicitly invoking the ALARP principle (Alberta Energy Regulator, 2024). Appendix P of D65 addresses the monitoring, measurement, and verification (MMV) requirements that mandate a comprehensive risk assessment process. These include: i) systematic identification of all risk scenarios capable of posing significant consequences; ii) quantitative or qualitative analysis of the likelihood and severity of each scenario, grounded in the best available scientific evidence; and iii) formal evaluation of whether the resulting risk level is tolerable or acceptable.

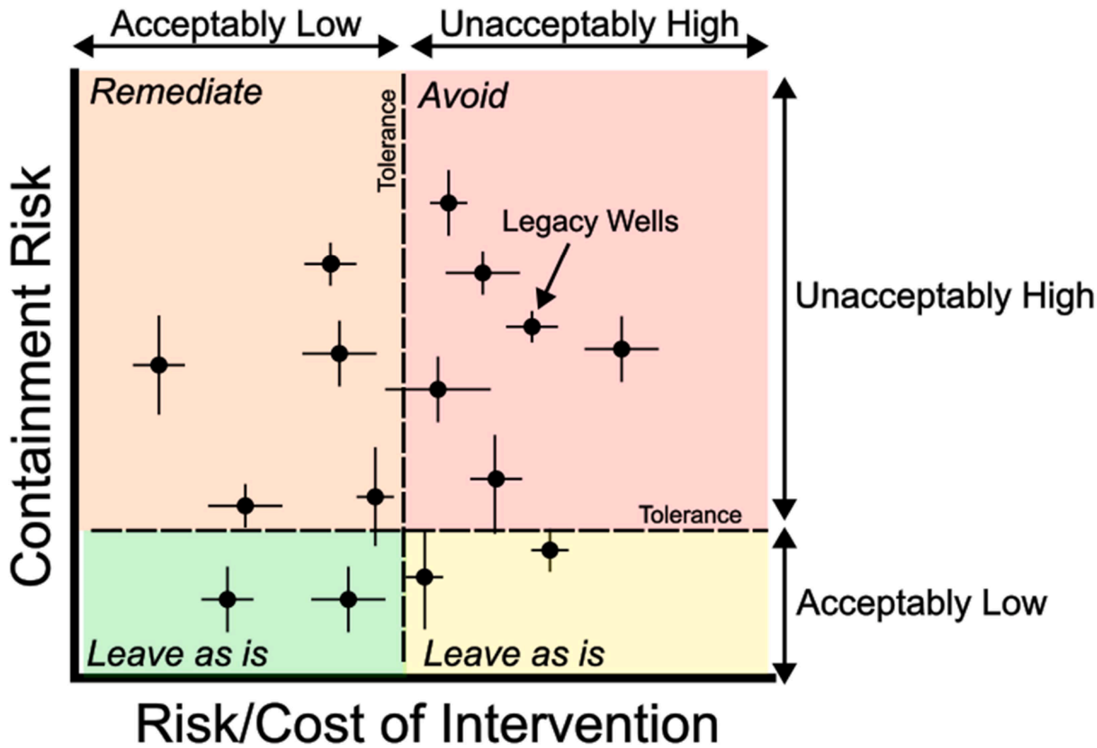

Fig. 6. Example decision space for legacy wells at GCS sites considering both the containment risk posed by a well and the risk or cost of intervention. Points represent legacy wells and bars represent the uncertainty associated with containment risk and risk or cost of intervention.

The Alberta approach aligns with the Canadian Standards Association standard CSA Z741, as referenced in D65, which requires that significant risks be reduced to and maintained at a tolerable or acceptable level through appropriate treatment strategies (Section 6.6.4). While the outcome is functionally comparable to the ALARP approach used in the EU and Australia, Alberta's regulatory language and methodology are distinctly framed around risk tolerability criteria rather than ALARP terminology.

The UK differs from the EU, Australia, and Alberta, in that operators must ensure that legacy wells pose no significant risk (NSR) of leakage or of harm to the environment or human health (North Sea Transition Authority, 2025). Unlike ALARP, NSR focuses on absolute assurance in permitting storage and demands evidence that risks are effectively negligible under the proposed conditions, without cost-benefit balancing (Stuart-Smith et al., 2025) (Table 3). The U.S. Class VI rule is unique in that it does not require a formal risk assessment for GCS sites or legacy wells. Rather, operators are required to evaluate wells using available well information or field characterization and perform remedial (i.e., corrective) actions as necessary to prevent fluid migration into shallow groundwater aquifers through wells (U.S. EPA, 2013).

In the petroleum industry, legacy well regulations historically apply ALARP for operational safety but shift to NSR for environmental containment, especially if wells are repurposed or assessed for long-term integrity. An argument against ALARP is that a cost-benefit analysis can be framed to exaggerate implementation costs while downplaying quantified benefits, justifying a lower safety threshold and rejection of further actions. This is particularly relevant to CO_2 storage, where a well intervention could be deferred by arguing that long-term risks are negligible in present-value terms. ALARP baseline assessments may also selectively overlook rare but high-consequence events to keep evaluations in the "tolerable if ALARP" zone by avoiding costly holistic assessments. These practices stem from ALARP's inherent subjectivity in harm quantification and cost evaluation. Regulators aim to counter this through careful oversight and requirements for transparent documentation. NSR addresses this directly by requiring an objective assessment that does not prioritize a cost-focused interpretation. NSR requires risks

Table 3
Comparison of regulatory methods for legacy well risk management.

Approach:	ALARP – As Low as Reasonably Practicable	NSR – No Significant Risk
Definition	Requires risk to be reduced to a level where further mitigation involves costs, time, or effort grossly disproportionate to the benefits gained. Balances risk based on cost-benefit analysis.	Focuses on absolute assurance that risks are effectively negligible under proposed conditions, without cost consideration. Risk elimination.
Origin/Usage	Common in health and safety law and industrial standards; applied in the EU CCS Directive and Guidance Documents (EC, 2024).	Used in UK regulations (North Sea Transit Authority, 2025); defers to CCS Directive definitions of 'significant risk' and 'leakage'.
Assessment Criteria	Allows some risks to be deemed acceptable or tolerable if costs are disproportionate; may overlook rare high-consequence events; subjective harm and cost evaluations	Requires objective assessment; risks must be reduced to the satisfaction of the regulator on a well-by-well and site-specific basis. No explicit consideration of cost.
Risk Tolerance	Higher residual risk tolerance: allows measure to stop at "good practice" e.g. standard industry measures, if regulator approves.	Lower overall tolerance: aims for near-elimination of risk e.g. multiple safety barriers and redundancy if required.
Application in Legacy Wells	In the petroleum industry, applies to operational safety; may defer high-cost interventions if long-term risks have a negligible present-value.	Environmental containment emphasis; robust measures for long-term integrity of all wells with potential exposure.
Arguments Against	Subjectivity can lead to exaggerating costs and downplayed benefits, justifying lower safety thresholds and overlooking risk events.	Costs can be prohibitive, limiting CO_2 storage development and displacing harm from emissions to atmosphere.

to be reduced to a level where the consequences of harm are so low that they are effectively negligible. This implies a near-elimination of risk. In practice, this may mean implementing safety measures regardless of cost. The argument against NSR is that the resultant cost is potentially so prohibitive that storage becomes limited, resulting in the displaced harm from emissions to the atmosphere. U.S. Class VI regulations are more closely aligned with NSR in that they do not allow for the consideration of a cost-benefit analysis; however, the lack of a formal risk assessment requirement may result in relevant risks being overlooked.

5.2. Locating wells

Surveying project areas to confirm the locations of documented legacy wells, or to identify undocumented legacy wells is an essential step for GCS projects (IPCC, 2005). While regulatory agencies and private companies maintain well databases that include location information in most regions, these databases often contain inaccurate or incomplete information (Dilmore et al., 2015; Jahan et al., 2025; Saint-Vincent et al., 2020). This is a major challenge in North America, where oil and gas drilling began prior to the establishment of regulatory agencies and modern record keeping practices (Interstate Oil and Gas Compact Commission (IOGCC), 2021). Consequently, hundreds of thousands of oil and gas wells drilled in the U.S. are currently undocumented or "lost" with unknown locations (Boutot et al., 2022; Kang et al., 2023; Merrill et al., 2023). Undocumented wells are often referred to as orphaned wells as they have no owner and the plugging responsibility has defaulted to the state. Documented wells with known locations can also be orphaned if their owner is no longer solvent. In the past decade, methods for identifying and characterizing lost or undocumented wells have advanced substantially through federally funded efforts to locate and plug orphaned oil and gas wells in the U.S. (O'Malley et al., 2024).

Magnetometers are widely used to identify legacy wells as they pinpoint well locations by detecting the magnetic signature of steel casings and can be flown over large areas (Frischknecht et al., 1983; Hammack et al., 2016; Saint-Vincent et al., 2020). Since 2015, advances in unmanned aircraft systems (UAS) technology and miniaturization of field magnetometers have provided an alternative to piloted magnetic surveys (Hammack et al., 2023, 2020; Nikulin and de Smet, 2023, 2019; Sams et al., 2017; Zheng et al., 2021). UAS can be flown closer to the ground with denser flight paths than piloted surveys, which allows for the detection of wells that would have previously required a terrestrial survey (Nikulin and de Smet, 2019; Sams et al., 2017). Applications of UAS-based aeromagnetic surveys at field sites in the Appalachian Basin have demonstrated they are faster, safer, and more efficient than piloted or terrestrial alternatives (De Smet et al., 2021; Hammack et al., 2023). Rotary UAS are primarily used for magnetic surveys as they have large carrying capacities and precisely follow survey lines. Researchers are exploring the use of fixed wing UAS for well finding surveys, which can cover larger areas more rapidly than rotary counterparts (O'Malley et al., 2024).

Recent work has emphasized the limited ability of magnetic surveys to detect legacy wells with pulled or wooden casings (Hammack et al., 2023; Reeder et al., 2023). High-resolution light detection and ranging (LiDAR) surveys are helpful for identifying these older legacy wells as images of bare-earth topography identify leveled well pads and signs of other well infrastructure such as old storage tanks, pipelines, and access roads that may now be covered with vegetation. Additionally, the soil surrounding older legacy wells also tends to subside when casings are removed or deteriorate, which creates a circular subsidence feature detectable with LiDAR (Hammack et al., 2023). Methane surveys can also help identify legacy wells; but are confounded by other sources of methane and are limited in that they can only detect leaking wells (O'Malley et al., 2024).

Deep learning is another rapidly advancing research area that has the potential to aid legacy well finding efforts. The resolution of remote sensing data is important when attempting to locate legacy wells (Saint-Vincent et al., 2020). Various multilayered neural network modeling approaches have shown promise when applied to sparse data reconstruction problems. Successful application of these models to low-resolution remote sensing datasets could increase their utility for well finding (Fukami et al., 2021; Santos et al., 2023). Multiple recent studies have also applied deep learning models to automate the detection of wells and their associated infrastructure in satellite imagery (Kadeethum and Downs, 2024; Kim et al., 2024; Ramachandran et al., 2024; Seth et al., 2025; Wu et al., 2023; Zhang et al., 2023), historical maps (Ciulla et al., 2024), and magnetic surveys (Bernstein et al., 2024). The ability of these models to identify legacy wells improves when multiple sources of information (e.g., magnetic and methane survey data) are provided (O'Malley et al., 2024). Automating well identification using deep learning methods reduces the manual input needed to digitize well locations from historic maps, aerial photos, and satellite images and speeds the preparation of well finding field campaigns, which are more successful when well location information from multiple sources is combined beforehand (Ciulla et al., 2024; Reeder et al., 2023). Preparation for field campaigns could be further reduced through real time identification of legacy wells in the field with UAS, which would allow for well detection and location verification in a single trip.

Research efforts related to legacy well finding are pushing towards region-scale applications to help improve regulatory well inventories (O'Malley et al., 2024). GCS project areas are relatively small when compared to the size and scale of regional well finding efforts. While existing technologies are sufficient to locate legacy wells at GCS sites, experience gained through the upscaling of well finding efforts will be valuable for GCS operators, and further advancements in UAV surveying, deep learning, and data integration have the potential to increase efficiency and reduce costs. Ultimately, improvement of regulatory well inventories will also benefit GCS operators and may reduce or remove the need to perform well finding surveys in some regions.

5.3. Integrity characterization

Characterization of legacy well integrity informs well screening and risk assessment and occurs at different scales during GCS project development. For example, a review of available well records early in the site selection phase could be sufficient to identify wells that should be avoided because they require complicated remedial actions. As a project develops, field verification of active or suspended wells may become essential to determine the feasibility of their re-use for monitoring or injection. In the past decade, researchers have advanced technologies that facilitate well record review, progress existing invasive techniques, and enable non-invasive well integrity assessments, which aid the integrity characterization of inaccessible wells.

5.3.1. Record review

The availability of information describing legacy well construction varies widely. In some regions, regulatory and proprietary well databases contain detailed well construction information in a structured format, which facilitates rapid well evaluations. If databases are unavailable, well regulatory records such as drilling, completion, and plugging reports are often the only source of well information (Patil et al., 2025). Well information is typically spread across multiple records, the format of which could be digital or non-digital depending on the age of the well (O'Malley et al., 2024). Most jurisdictions have scanned well regulatory records that are available online or through request or purchase, but this process is ongoing as some jurisdictions still rely on the submission of paper forms and have large backlogs of historical records to scan. Scanning records produces a digital image of the file but does not digitize the text contained in the form, which must be manually read to understand well construction. The manual review of well documents becomes impractical as the number of legacy wells considered increases. For example, a recent construction analysis of 156 offshore wells along the Texas Gulf Coast necessitated the review of 1200 regulatory records (Lackey et al. 2024).

Advances in artificial intelligence and machine learning over the past decade have created the field of Intelligent Document Processing (IDP). IDP tools address multiple issues relevant for digitizing scanned images of records including: (i) splitting files that include multiple documents, (ii) sorting documents by type and format, (iii) cleaning and rectifying documents, (iv) digitizing and cleaning document text, and (v) facilitating human review for error correction (Baviskar et al., 2021). Researchers have leveraged commercially available IDP tools to create custom software designed to digitize well records (Chen et al., 2021; Dong et al., 2022; O'Malley et al., 2024). One such tool was designed for GCS and automates the drawing of well diagrams to identify leakage pathways (Chen et al., 2021; Dong et al., 2022). Researchers are also exploring the application of large language models for data extraction from well records, which could reduce the need to label documents and fields—a manually-intensive process required by many commercial IDP tools (Colman et al., 2025; Ma et al., 2024). The maturation of custom IDP tools for well record digitization has the potential to reduce the effort required to evaluate legacy well construction at GCS sites and increase the availability of well information in regulatory and proprietary databases.

5.3.2. Invasive methods

Integrity characterization methods for accessible wells are established and widely used in the oil and gas industry. A variety of wireline logging tools are available that provide insight into the status of well materials (Taleghani and Santos, 2023). Technologies used for well evaluation include, among others, acoustic tools (sonic and ultrasonic), passive noise logs, temperature logs, resistivity logs, gamma ray logs, neutron logs, oxygen activation logs, X-ray logs and various fiber optic measurements (e.g., Ghosh, 2022; Khalifeh et al., 2017). Most conventional logging techniques allow evaluation of cement quality behind a single steel pipe, which means that the production tubing typically needs to be pulled out to log the casing cement. Recent technology developments aim to extend this reach and enable "through-tubing" or "dual-string" logging, i.e. to allow simultaneous evaluation of two annuli without having to remove the inner pipe (Alimuddin et al., 2025; Singh et al., 2024). Methods such as pressure surveys are also widely used to test and monitor the integrity of well barriers. However, characterizing the integrity of plugged and abandoned wells is more challenging. Upon abandonment, wellheads are typically removed, and casings are cut and capped below surface. *Re*-entry of a plugged and abandoned well is expensive (especially offshore) and may be technically infeasible for older wells that lack casings, have degraded materials, or were plugged with debris.

5.3.3. Non-invasive methods

Electromagnetic methods have been proposed as low-cost, non-invasive alternatives for characterizing well integrity (Beskardes et al., 2021; MacLennan et al., 2018; Romdhane et al., 2022a; Wilt et al., 2019, 2020). Wilt et al. (2019) demonstrated a proof-of-concept for the top-casing method—a well integrity characterization approach that involves applying a low-frequency electromagnetic current to a well casing at the surface. Electric field data are collected from a distant return electrode and a numerical model is used to identify casing depths and areas of damage. Beskardes et al. (2021) progressed the top-casing method by considering the impact of various well designs and damage types on electromagnetic signals. Romdhane et al., 2022a and Zonetti et al. (2023) numerically modeled the application of the top-casing method to detect corrosion in a legacy well at the Frigg Field in the North Sea. While initial results show promise that electromagnetic inversion can detect and predict well failures, further work is needed to understand how noise and uncertainty in the conductivity field impact the detectability of well damage. Development of other non-invasive methods for well integrity would also be valuable.

5.4. Screening

In mature basins, hundreds to thousands of legacy wells may lie within a GCS project area or areas considered (Gasda et al., 2004). One problematic well can substantially impact the cost and, ultimately, the viability of a GCS project (Torsæter et al., 2024). While a full integrity evaluation of each well, through detailed records checks, construction diagrams, barrier evaluations, and risk assessments, remains the gold standard, it is far too resource-intensive to conduct at the early site appraisal stage of a project. This mismatch between regulatory requirements and the realities of time and cost has driven the development of legacy well screening approaches, which occupy the front end of legacy well risk management workflows.

Legacy well screening approaches are typically paper exercises that rely on the evaluation of well construction information (e.g., depth, casing design, cement design) and basic geologic details of the permitted storage zone (e.g., depth of reservoir(s) and caprock(s)) to separate wells into categories (Anwar et al., 2025; Arbad et al., 2022; Emmel and Dupuy, 2021; Lackey et al., 2024; Pullen et al., 2025). More involved approaches that include non-invasive methods for well integrity evaluation have also been proposed (Romdhane et al., 2022a; Zonetti et al., 2023). Legacy well screening approaches are underpinned by the concepts of risk assessment; however, they are generally less involved than a full risk assessment, and often only identify potential hazards. Screening approaches differ mainly in the level of data required and the resolution of the outputs. At one end are coarse assessments that rely on the simplest regulatory records; at the other are more data-rich frameworks that consider all available well information. Most legacy well screening approaches have been developed in the past decade alongside the expansion of GCS to brownfield sites.

5.4.1. Risk scoring

The calculation of well leakage potential or "risk" scores is one widely applied approach for legacy well screening (Azzolina et al., 2015; Buxton et al., 2015; Cahill and Samano, 2022; Duguid et al., 2019; Emmel and Dupuy, 2021; Glazewski et al., 2014; Lackey et al., 2019; Patil et al., 2022; Pullen et al., 2025; Romdhane et al., 2022a). While some risk scoring approaches use well construction details (e.g., casing depths, cement locations) (Duguid et al., 2019; Emmel and Dupuy, 2021; Romdhane et al., 2022b), most rely on location, status, key dates, depth and other high-level information that is readily available in well databases (Azzolina et al., 2015; Buxton et al., 2015; Cahill and Samano, 2022; Lackey et al., 2019; Pullen et al., 2025). Proposed well risk scoring approaches assign individual scores to a set of well attributes relevant to well integrity, with higher scores given for factors that are either associated with the increased potential for integrity loss through heuristic, statistical (Duguid et al., 2019; Lackey et al., 2019), or expert elicitation methods (Pullen et al., 2025). Attribute scores are then aggregated for each well to determine a final risk score using different methodologies that range from simple, such as addition or multiplication (Duguid et al., 2019; Glazewski et al., 2014; Lackey et al., 2019), to more complex, such as weighted-sum multi-criteria models (Pullen et al., 2025). Wells with higher scores are considered greater risks to containment than wells with lower scores.

Most well risk scoring approaches developed for screening were inspired by the observations of Watson and Bachu (2009). Watson and Bachu (2009) analyzed well integrity testing records from over 300,000 wells in Alberta to show that broad well attributes such as construction era, deviation, abandonment quality, and geology could be used to triage well populations with a higher risk of experiencing integrity issues. Since 2009, efforts have been made to link well attributes to integrity issues recorded in regulatory databases with rigorous statistical and machine learning methods (Lackey et al., 2025; Li et al., 2018, 2025; Montague et al., 2018; Sandl et al., 2021; Zheng et al., 2024). While predictive modeling efforts have shown promise, the best performing models make correct predictions for only 60–80% of wells considered (Montague et al., 2018; Sandl et al., 2021). Many well attributes used as explanatory variables in well integrity prediction models are collinear and/or spatially autocorrelated, which complicates the identification of independent relationships between well attributes and integrity loss (Lackey et al., 2025; Sandl et al., 2021). Additionally, well integrity issues are often spatially clustered. As a result, well location is the most important feature in multiple well integrity prediction models suggesting that model performance is unlikely to generalize to regions without training data (Lackey et al., 2025; Li et al., 2025; Sandl et al., 2021).

When considered in aggregate, recent analyses of regulatory well integrity testing data highlight the limitations of well risk scoring methods. The value of well risk scoring depends on the ability of the scoring scheme to predict integrity issues or the presence of leakage pathways. Proposed risk scoring methods are unlikely to be accurate predictors of integrity issues as they do not use rigorous well integrity prediction models and, if they did, the performance of the best well integrity prediction model is not sufficient to reliably inform risk mitigation decisions. Additionally, the implicit assumption that well integrity prediction models would apply to legacy wells at GCS sites is questionable as these models are trained with integrity testing data collected from active oil and gas wells, which may be in a different condition than older legacy wells and are not exposed to the unique subsurface conditions created by GCS. The focus of most well risk scoring methods on well integrity issues also ignores leakage pathways that may already be present along wells such as uncemented annuli or improperly placed plugs. Thus, applications of well risk scoring methods for GCS site permitting are limited; however, these methods are one option for characterizing the condition of legacy wells across large regions when data availability is a challenge. In this context, these efforts may be valuable to researchers, regulators, and other stakeholders seeking to understand the feasibility of GCS in a region prior to project planning if they are applied correctly and validated with existing data. Otherwise, simple screening methods that use basic information such as well depth may be the only viable option.

5.4.2. Construction evaluation

Detailed evaluations of legacy well construction are another widely applied well screening method (Anwar et al., 2025; Arbad et al., 2024b, 2024a, 2022; Haagsma et al., 2015; Lackey et al., 2024; Patil et al., 2025, 2024; Sminchak et al., 2014). At the highest level, depth is used to screen wells that penetrate the permitted storage zone or its caprock. The availability of well construction records enables forensic assessments of construction, which focus on identifying leakage pathways that pose a risk to CO_2 containment as well as determining the feasibility of performing corrective action. Leakage pathways are identified by comparing well construction details with geologic information to determine if well features such as uncemented annuli, open holes, or improperly placed plugs will permit injected or native fluids to leak upward along the well (Anwar et al., 2025; Arbad et al., 2022; Lackey et al., 2024; Patil et al., 2025). The feasibility of corrective action depends on the accessibility of the wellhead (which could be societally inaccessible if the well is located under a building or near a sensitive location such as a school) and the presence of complicating downhole factors such as stuck equipment (i.e., fish), sidetracks, or open holes (Anwar et al., 2025; Arbad et al., 2022; Lackey et al., 2024; Patil et al., 2025). Well construction evaluations also directly inform risk assessments (International Association of Oil & Gas Producers, 2023).

Studies that have developed screening methods based on well construction evaluation rely on categorization schemes that are either granular in that there is one category for every well type (Arbad et al., 2024a, 2024b, 2022) or modular in that they separately categorize relevant aspects of well design and aggregate them (Anwar et al., 2025; Lackey et al., 2024) (Fig. 7). Well construction categories are used either directly to screen wells (Anwar et al., 2025; Arbad et al., 2022) or feed into a separate screening system (Lackey et al., 2024). Well categories in the approach proposed by Arbad et al. (2022) are qualitatively aligned with a risk matrix, which screens wells as higher risk if they have leakage pathways and are difficult to access or lower risk if they can be accessed and have fewer pathways. Similar to Arbad et al. (2022), the screening approach proposed by Patil et al. (2024) (used by Lackey et al. (2024)) also screens wells by the presence of leakage pathways and accessibility of the well. Anwar et al. (2025) proposed a separate approach that screens wells using well construction categories combined with qualitative risk scores aggregated for each individual leakage pathway.

Only a subset of well construction evaluation studies consider cement quality along the depth of a well (Haagsma et al., 2017, 2015;

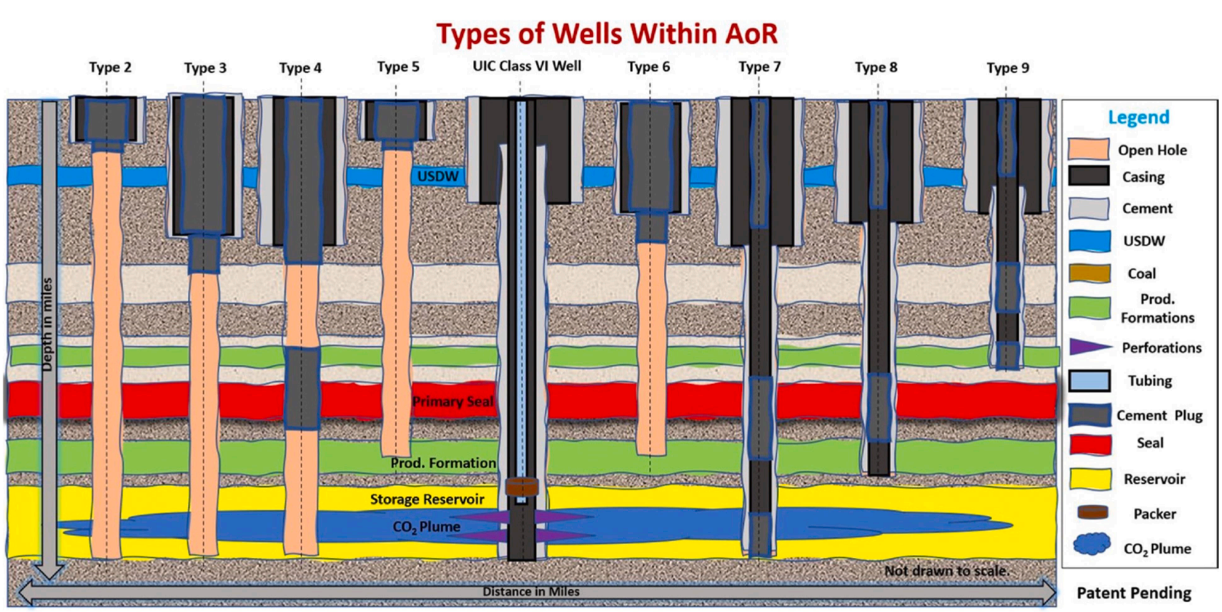

Fig. 7. Well categorization system developed by Arbad et al. (2022) for legacy wells in the Illinois Basin. Nine variations of legacy well construction are shown with respect to the target reservoir and primary seal. A well that meets U.S. EPA Class VI construction requirements is also shown for comparison. This figure was used with permission of the authors.

Sminchak et al., 2014). Haagsma et al. (2015) proposed a method that scores legacy wells using cement bond index— a normalized interpretation of cement bond log data calculated using maximum and minimum recorded amplitudes. While cement bond logs offer additional insight into the location and quality of cement in a legacy well, their availability is limited among older legacy wells and field validations of the relevance of the cement bond index to gas wells are needed as cement bond logs do not reliably detect gas-filled microannuli (Brown et al., 1971; Wang et al., 2016).

Screening methods based on well construction evaluation have more applications for GCS site permitting than well risk scoring approaches. While it is difficult to perform well construction evaluations in jurisdictions where well construction details are not available in structured digital databases, detailing the construction of legacy wells with respect to the permitted storage zone is generally a requirement for injection permits. Analyses of legacy well construction details may also be sufficient to justify risk mitigation decisions in jurisdictions where formal risk assessments are not required (e.g., U.S. EPA Class VI). However, additional analyses that determine the likelihood and consequence of leakage along legacy wells are needed where formal risk assessments are required.

5.5. Risk assessment

Formal risk assessments that characterize the probability and consequence of negative scenarios such as the occurrence of legacy well leakage are required for GCS site permitting in most jurisdictions. Risk assessments also inform risk mitigation decisions. After screening, decisions for a subset of wells may be unclear without deeper analysis. These unresolved wells could have records that suggest the presence of sufficient well barriers, be located on the periphery of the project area, or be subject to subsurface processes that close off well leakage pathways. Risk assessments create a structured method for weighing leakage risks against other trade-offs to determine the best course of action. In jurisdictions where risk assessments are not required, it may not be necessary to perform a full risk assessment to justify well management decisions. However, a thorough characterization of legacy well conditions using invasive techniques (e.g., wireline logging tools) if entry or re-entry is possible, non-invasive techniques, or modeling may still be needed after screening to meet permit requirements.

Risk assessment has been a major focus of GCS research for over two decades. Many qualitative, semi-quantitative, and quantitative risk assessment approaches have been developed and applied at different projects, most of which were adapted from analogous industries and were in use by 2015. A summary of GCS risk assessment approaches is provided in Pawar et al. (2015) and also in more recent reviews (Gholami et al., 2021; Hajiyev et al., 2025; Su et al., 2023; Xiao et al., 2024). In the past decade, multiple organizations such as the International Association of Oil and Gas Producers (IOGP) and the U.S. Department of Energy have published recommended practices that illustrate the use of various risk assessment methods at GCS sites (IOGP, 2023; Thomas et al., 2022). Qualitative and semi-quantitative risk assessment approaches such as the bowtie method have also become well established through their use in the development of measurement, monitoring, and verification plans for GCS operations (e.g., Dean and Tucker, 2017). Consequently, most risk assessment research progress in the past decade has focused on the development of quantitative methods, which use numerical or analytical models to quantify fluid leakage rates and/or the degree of their impact on sensitive receptors through the simulation of the physical and chemical processes associated with GCS in the subsurface. Quantitative approaches are often designed to be probabilistic to capture the inherent uncertainty associated with subsurface systems. The two major categories of quantitative risk assessment approaches that have been the subject of research over the past decade are (i) site performance assessment modeling and (ii) scenario-based modeling.

5.5.1. Site performance assessment models

Many early well leakage modeling studies focused on site-level predictions of legacy well leakage over the course of a CO_2-EOR or GCS project. These models used probabilistic methods to estimate the percentage of injected CO_2 contained in the permitted storage zone over long time periods. The primary goal of these early efforts was to understand the feasibility of GCS as an enterprise (Metcalfe et al., 2013; Walton et al., 2005). Concepts from early studies progressed into performance assessment models, that use a system modeling approach to dynamically simulate leakage risks over the lifetime of specific projects (LeNeveu, 2008; Oldenburg et al., 2009). Most performance assessment models were developed prior to 2015 and are summarized in Pawar et al. (2015).

One performance assessment model that has been continuously developed over the past decade is the U.S. Department of Energy's National Risk Assessment Partnership (NRAP) Open-Source Integrated Assessment Model (NRAP Open-IAM) (Vasylkivska et al., 2021). NRAP Open-IAM builds on previous versions of the tool (NRAP IAM-CS, CO_2-PENS) that were designed to facilitate probabilistic risk assessment (Pawar et al., 2016; Stauffer et al., 2009). Rapid simulation in NRAP Open-IAM is achieved through a system of coupled reduced order models that simulate the physical processes in reservoirs, leakage pathways, and receptors. In the past decade, the capabilities of NRAP Open-IAM expanded, and the tool has been applied by many case studies. Researchers developed three well models for NRAP Open-IAM that simulate CO_2 and brine flow through: (i) a fully cemented wellbore (Harp et al., 2016), (ii) a wellbore with multiple sections of cement that have varying permeability (Baek et al., 2025, 2023; Nordbotten et al., 2009, 2005), and (iii) a completely open wellbore with no plugs (Bacon et al., 2021; Pan et al., 2011). Reduced order models of groundwater aquifers (Bacon et al., 2016; Keating et al., 2016) and atmospheric dispersion (Zhang et al., 2016) have also been developed that receive outputs from well leakage models to quantify leakage impacts. Dynamic risk simulation capabilities were also developed for NRAP Open-IAM that assimilate monitoring data as it becomes available from a project (Chen et al., 2023, 2020). To the authors knowledge, at least 16 case studies have applied NRAP Open-IAM to prospective and operational GCS projects in the Appalachian, Illinois, Paradox, Permian, San Juan, Raton, and San Joaquin basins in the U.S., the Taishi basin in Taiwan, and the Ordos basin in China (Bacon et al., 2020; Chu et al., 2024, 2023; Cumming et al., 2019; Doherty et al., 2017; Gan et al., 2021; Kim et al., 2025; Mitchell et al., 2023; Ning et al., 2025; Onishi et al., 2019; Skopec et al., 2022; Xiao et al., 2025, 2019; Yang et al., 2024; Yu et al., 2024; Zulqarnain et al., 2017). These studies applied NRAP Open-IAM to calculate the mass of CO_2 retained in the reservoir over the project lifetime, determine risk-based project areas, estimate the detectability of CO_2 and brine leakage in aquifers, justify risk-based post-injection site care periods, and explore the efficacy of risk mitigation measures such as brine extraction.

Another site performance assessment model that progressed in the past decade is the Analytical Solution for Leakage in Multilayered Aquifers tool (ASLMA) (Cihan et al., 2013, 2011). ASLMA contains a multiple analytical and semi-analytical methods that calculate CO_2 and brine flow through wellbores. Oldenburg et al. (2016) proposed a computational framework for estimating project areas using the ASLMA approach. The approach proposed by Oldenburg et al. (2016) was progressed and formalized into a risk mapping approach by Siirila-Woodburn et al. (2017). Burton-Kelly et al. (2021) applied ASLMA to determine the project area of a GCS site operating in an overpressure reservoir in North Dakota and showed that the tool can satisfy U.S. Class VI permitting requirements.

NRAP Open-IAM, ASLMA, and other GCS site performance assessment models have consistently estimated relatively low volumes of CO_2 and brine leakage through legacy wells at GCS sites in case study applications. For example, Zhou et al. (2005), one of the earliest applications of the site performance modeling approach, used a reservoir simulator to estimate that CO_2 leakage through abandoned wells at the Weyburn CO_2-EOR field will likely remain below 0.001% of the injected volume over a 5000-year period. More recently, Lackey et al. (2019) used NRAP Open-IAM to estimate a maximum of 2.4 t of brine and 10, 200 t (4.1×10^{-5}%) of CO_2 leakage over a 100-year period from a hypothetical 250 Mt injection in the vicinity of 1000 legacy wells. These studies assumed effective well permeabilities between 1 D and 10 μD (10^{-12} and 10^{-17} m^2), which are at the higher end of the range estimated (1 D-10 nD; 10^{-12}–10^{-20} m^2) for abandoned wells (Carey, 2018). The low probability of leakage from GCS sites has also been supported by GCS industry-level modeling efforts, which estimated a 50% probability that the yearly leakage of CO_2 from GCS will remain below 0.0008% (Alcalde et al., 2018).

The progress made with GCS site performance assessment modeling addresses some of the research goals outlined by Pawar et al. (2015) on the 10th anniversary of the SRCCS report. The capabilities and applications of flagship tools like NRAP Open-IAM and ASLMA have grown substantially over the past decade. While model results remain uncertain and difficult to validate with real data, model outputs continue to be useful for understanding site level containment risks over the lifetime of projects. However, gaps remain in the functionality of these tools, especially for site permitting. Gupta et al. (2024) reviewed the applicability of the NRAP Open-IAM for U.S. Class VI permits and found that many permit applicants had not used the tool because of limited input parameter ranges, questions that could not be addressed by the tool, a lack of sufficient information to generate site-specific results, and a hesitancy to use non-industry standard software. This highlights the need to continue developing GCS site performance assessment models with a focus on implementing new functionality useful for site permitting if these tools are to be useful outside the context of research.

5.5.2. Scenario-based modeling

The implementation of GCS at sites with legacy wells has created a need for scenario-based well leakage models. Scenario-based models focus on simulating specific leakage mechanisms in wells to support site permitting. An example of a scenario-based well leakage model is provided by Neele et al. (2019), which developed a finite-element numerical model to determine if cold CO_2 injection in wells at the Porthos project would create a cement microannulus at casing and/or caprock interfaces. Simulation results demonstrated the potential for microannulus formation but estimated negligible leakage (<0.00001% of CO_2 injected annually) under storage conditions. The model developed by Neele et al. (2019) directly informed site permitting by quantifying a specific leakage scenario identified in the project risk assessment.

Over the past two decades, the GCS research community has primarily pursued the probabilistic approach for well leakage modeling used by GCS site performance assessment models (Jenkins, 2023). The probabilistic approach treats wells as a continuous porous medium with an effective permeability representative of well conditions that are highly uncertain. A range of leakage rates is estimated through stochastic simulation and sampling of well permeabilities from a distribution (Celia et al., 2011; Cihan et al., 2013, 2011; Nordbotten et al., 2009; Vasylkivska et al., 2021). This approach is valuable for estimating site-level leakage risks, which has applications for site permitting (e.g., creating risk-based justifications for the project area); however, it informs only one well leakage scenario—CO_2 or brine flow through a compromised cement sheath. Researchers have developed modeling approaches for other leakage scenarios such as blowouts (Bhuvankar and Cihan, 2025), gaps between casings and bridge plugs (Pan and Oldenburg, 2020), and microannuli (Lavrov and Torsæter, 2018; Moghadam and Amiri, 2025). These studies have primarily illustrated their approaches on hypothetical wells to understand factors that influence leakage. Jenkins (2023) highlighted the need for increased sharing of legacy well case study information. Increased sharing of scenario-based well leakage models developed for real GCS projects would also be valuable to progress quantitative risk assessment research.

5.6. Risk mitigation

Traditional risk mitigation strategies for legacy wells include avoidance, plugging and abandonment (P&A), remediation, and re-use. These measures are typically combined with long term monitoring integrated into the measurement, monitoring, and verification plan for the project. The mitigation strategy chosen depends on the condition of the well, the characteristics of the site, and other factors such as project economics. In the past decade, technologies and methodologies for legacy well remediation and re-use have progressed. Researchers have also begun exploring non-traditional methods for legacy well risk mitigation, such as confirming or enhancing the natural sealing of wellbores. Additionally, we review well intervention costs, which are slowly becoming available with the implementation of GCS. We chose not to review legacy well plugging and abandonment technologies and advances in monitoring methods. Industry guidelines and regulatory requirements for well plugging and abandonment (P&A) are established and innovation with P&A technology has been limited (NOGEPA, 2021; NORSOK, 2013; OEUK, 2022a, 2022b, 2022c). While recent work by Bakhshian et al. (2025) focused on a low-cost monitoring method for legacy wells at GCS sites, many widely used leakage monitoring technologies for GCS are suitable for monitoring legacy wells and have been the subject extensive reviews (Jenkins, 2020; Jenkins et al., 2015).

5.6.1. Remediation

Conventional methods for remediation of annular fluid migration along wells include perforate-and-squeeze cementing as well as section-milling and recementing. Perforate-and-squeeze cementing involves high-pressure injection of cement slurry through perforations made in the casing pipe (Cowan, 2007; Slater, 2010; Winarga and Dewanto, 2010). Section-milling and recementing describes the mechanical removal of the existing casing and cement over a specified interval, which subsequently enables the placement of a new cement plug that spans the full bore of the milled window (Joppe et al., 2017; Nelson et al., 2018; Obodozie et al., 2016).

Several advances in remediation technology have been made in the last decade, with the development of new sealant materials and optimized placement techniques (Bothamley et al., 2020; Lucas et al., 2018). Given the relatively low success rate of conventional squeeze cementing operations (typically below 60%; Cowan, 2007), alternatives for squeezing cement explored in recent years include the injection of different low-viscosity epoxies and resins (Beharie et al., 2015; Beltrán-Jiménez et al., 2025; Genedy et al., 2014; Leng et al., 2024; Todorovic et al., 2016; Vicente et al., 2017) and several types of mineral-precipitation based solutions (Hangx et al., 2025; Kirkland et al., 2020; Taheri et al., 2025; Wasch and Koenen, 2019; Wolterbeek and Hangx, 2021). Recent developments in plugging materials include geopolymers (Erguler and Taleghani, 2025; Hajiabadi et al., 2023) and metal alloys (Carpenter et al., 2001; Hmadeh et al., 2024; Lucas et al., 2023). Thermite has also been explored as potential alternative to section-milling and recementing (Carragher and Fulks, 2018; da Silva et al., 2023; Rosnes et al., 2024). Thermite is a metal-metal oxide powder mixture that, upon ignition, releases large amounts of energy via an exothermic oxidation–reduction reaction. This released energy can melt the casing pipe and thermally decompose the cement, where the resulting reaction products are expected to create an impermeable plug after the materials cool down and solidify (Rosnes et al., 2024).

A novel method for annular cement repair is Localized Casing Expansion (LCE). In this technique, the casing pipe is mechanically deformed to permanently enlarge its diameter. This compresses the volume of the surrounding cemented annulus, closing off leakage pathways like microannuli or fractures, and densifying the cement matrix (Kupresan et al., 2014, 2013; Radonjic and Kupresan, 2014). In recent years, two field tools have been developed to impose the required casing expansions in real wells. Experimental work has shown that LCE-treatment using these tools is highly effective in the repair of casing-cement microannuli (Wolterbeek et al., 2021b) and free-water channels up to several millimeters wide (Beltrán-Jiménez et al., 2022). LCE-technologies have been successfully deployed to remediate fluid migration along wells in Canada (Wolterbeek et al., 2021b), the United States (Foerstner et al., 2025; Green et al., 2021), Kazakhstan (Mendybayev et al., 2024), and Romania (Cirstian and Preda, 2025).

It should be noted that the choice of techniques and equipment available for remediation depend on well status, specifically on accessibility of the borehole. Despite the advances made in the last decade, most of the technologies discussed require wellbore entry. Many legacy wells, especially if plugged and abandoned a long time ago, no longer have a wellhead or associated surface infrastructure. While for land wells it may be possible to excavate the cut-off casing stump and (depending on its corrosion status) reinstall a temporary wellhead, one of the key challenges for remediation operations of minor leaks may in fact become regaining access to the wellbore. Conventional options for well re-entry, up to and including the drilling of a relief well, are highly complex operations that will likely require a drilling rig or other significant material equipment to carry out (Torsæter et al., 2024). The environmental footprint of such operations should be taken into consideration, because the short-term emissions associated with the intervention operation could outstrip those associated with legacy well leakage. Advances in drilling rig electrification aim to reduce these emissions (Al Hadidy et al., 2024; Landry et al., 2024). Drilling into an existing CO_2 plume will also bring technical challenges, as CO_2 is more soluble in drilling fluids than natural gas (Feneuil et al., 2025). Recent research aims to develop software tools to confidently model CO_2-drilling fluid behavior and facilitate timely kick-detection (Skogestad et al., 2024). Efforts to reduce the risk and cost associated with the intervention of inaccessible legacy wells, especially offshore, would be valuable.

5.6.2. Re-use

Re-use of legacy wells for GCS as injection, monitoring or production wells is a potentially viable strategy for GCS projects that can reduce project costs. Multiple GCS projects are either being developed or explored around the world in depleted oil and gas fields, including Porthos (Netherlands), Greensand (Denmark), Acorn (UK), Prinos (Greece), Ravenna (Italy), Sarawak (Malaysia) and Gundih (Indonesia). Past pilot projects such as Lacq (France) & Cortemaggiore (Italy) successfully converted wells in depleted natural gas reservoirs for CO_2 storage field testing and demonstration (Global CCS Institute, 2025). GCS regulatory frameworks, such as the U.S. EPA's Class-VI regulations, allow for conversion of existing oil and gas wells into CO_2 storage wells if it can be demonstrated that the wells will maintain their integrity over the expected subsurface conditions over lifetime (U.S. EPA, 2013).

Marbun et al. (2019) and Marbun et al. (2023) detail a well re-use assessment performed on an existing well in the Gundih depleted gas field in Indonesia that is being converted to a CO_2 injector. Similarly, Neele et al. (2019) report results of the assessment performed to convert existing wells in the Porthos field, a depleted gas field, near offshore Netherlands. These studies emphasize the need for careful well integrity evaluation when reusing existing wells for GCS. Thorough well integrity assessments are important because oil and gas wells are designed for specific operational conditions that are different from CO_2 storage conditions. Workovers may be needed if CO_2 storage conditions lie outside safe operational envelopes for well equipment. Integrity assessments include characterization of all wellbore components using applicable technologies such as cement bond logs, caliper logs, and other specialized tools. Considering the effect of historic and expected wellbore operations (including the degree of casing wear that has or will occur) and operating conditions on well materials through numerical modeling can also provide valuable insight into the performance of well materials under GCS conditions (Marbun et al., 2023, 2019; Neele et al., 2019). Critical considerations include exposure of well materials to CO_2-rich fluids and potential cooling near the injectors in depleted reservoirs (Neele et al., 2019).

A screening tool was developed by the REX-CO_2 project to help determine the suitability and feasibility of reusing existing wells for CO_2 storage operations (Pawar et al., 2021). This tool and its associated workflow filled gaps in standardized methods for well re-use. The REX-CO_2 workflow uses a decision tree approach to guide a stakeholder through the multiple steps of a qualitative, technical assessment that compares the construction and condition of an existing well to the functional and integrity-related requirements of a CO_2 storage well. The objective of the REX-CO_2 workflow is to ensure that a reused well can maintain its integrity under expected operational and environmental conditions over its lifetime. Sub-assessments of the REX-CO_2 workflow include well integrity, out of zone injection risk, well structural integrity and well material compatibility. The REX-CO_2 tool was designed for pre-feasibility assessments to screen candidate wells at a potential GCS sites (Pawar et al., 2021).

5.6.3. Natural or stimulated well sealing

Formation creep is a natural factor that has been demonstrated to seal pathways in wellbores. Shales and salt formations have unique properties that cause them to deform under large stresses through creep and plastic processes (Holt et al., 2020; Pluymakers et al., 2014). The propensity for shale and salt to move inward toward the center of the wellbore during and after drilling is a well-known phenomenon. Researchers have traditionally studied the deformation and failure of rocks along wellbores in the context of borehole stability to design mud programs that avoid borehole collapse and stuck pipe (Hawkes et al., 2000; Holt et al., 2015). However, interest in the ability of creeping shale and salt formations to form natural seals (i.e., self-sealing) along wells for the purpose of simplifying plugging and abandonment operations has grown substantially over the past decade (Buijze et al., 2022; Fjær et al., 2023).

Most research on natural well sealing has focused on shales from the North Sea (Fjær et al., 2023; van Oort et al., 2022a, van Oort et al., 2024). Studies have developed experimental methods that use modified triaxial cells to test the capacity of shales to form a seal at reservoir conditions (Fjær and Larsen, 2018; Thombare et al., 2020). The sealing ability of shales has also been demonstrated using finite-element numerical models populated with rock properties measured during laboratory testing (Enayatpour et al., 2019; Fjær et al., 2016) and pressure tests performed in the field (Williams et al., 2009). Sealing of well leakage pathways with rock salt (i.e., halite) formations in the North Sea have also been explored through field (Loizzo et al., 2024) and numerical studies (Orlic et al., 2019) but have been less of a research focus.

Shales that form barriers exhibit ductile behavior and have low shear stiffness, Young's modulus, cohesion, unconfined compressive strength, and friction angle. In general, these shales are high porosity with low permeability and have a high clay content (in particular smectite) and low quartz and carbonate content (low matrix cementation) (Fjær et al., 2023). Shale barriers can be facilitated (i.e., "activated") by heating the wellbore (Bauer et al., 2017; Xie et al., 2020), dropping the annular pressure (Kristiansen et al., 2021, 2018), or changing the annular fluid chemistry (Gawel et al., 2021; van Oort et al., 2022a). Sonic and ultrasonic logging tools can detect shale barriers if they are calibrated on seals confirmed through pressure testing (Diez et al., 2022; Holt et al., 2017; van Oort et al., 2022b; Williams et al., 2009).

Shale has been accepted as a barrier for the purposes of well plugging and abandonment by the Norwegian Petroleum Safety Authority (PSA) for nearly two decades. The Norwegian PSA accepts shale barriers because they can form impermeable, long term, non-shrinking, and ductile seals that meet the requirements of NORSOK D-010 (Williams et al., 2009). Shales with sealing properties have also been documented in the U.S. Gulf Coast (Clark et al., 2005; Davis, 1986; Johnston and Knape, 1986; Nicot, 2009; Warner et al., 1997). However, most reports of sealing shale in the U.S. Gulf Coast are qualitative. Only Clark et al. (1987) has quantified the sealing ability of Gulf Coast shales to demonstrate that natural well closure can reduce the long-term risks associated with hazardous waste injection. The authors drilled a test well near Orangefield, Texas and measured the ability of Miocene-age shale to close a 27.9 cm (11 inch) open hole. The authors found that shale closed the hole within one week and pressure tested the seal to 0.97 MPa (140 psi).

Natural sealing of legacy well leakage pathways is an important future research area for GCS. Shale or salt sealing of microannuli, partially cemented or uncemented well annuli, or uncased open holes, has the potential to substantially reduce the need for well plugging and corrective action. Relying on natural sealing processes may also be the only technically viable option for some wells that are inaccessible due to borehole collapse or a previous plugging and abandonment operation. While many studies have considered the impact of CO_2 on shale swelling in the context of caprocks (Busch et al., 2016), studies of natural sealing under conditions relevant to GCS are limited to shale sealing of CO_2 injection well annuli (van Oort et al., 2024). More work is needed to understand the performance of natural shale and salt seals for all potential legacy well leakage pathways under reservoir conditions expected at GCS sites with exposure to relevant reservoir fluids (e.g., brine, CO_2 saturated brine, or supercritical CO_2) (Fig. 1). Methodologies for validating natural well barriers without direct access to a well would be particularly valuable. Regulatory acceptance of shale annular barriers for well plugging and abandonment require field demonstrations, laboratory testing, and numerical modeling efforts. Thus, it is reasonable to expect that field, laboratory, and modeling studies will be needed to gain confidence in natural well sealing for GCS.

5.6.4. Cost

The problem of costing legacy well interventions has been central to GCS project development for decades, from early risk assessment to operational site management and decommissioning (Torsæter et al., 2024). However, given the small number of projects that have undertaken interventions, and sparse data on related costs and outcomes, it remains challenging to identify representative and meaningful costs. The very small amount of data available suggests that costs per legacy well potentially run to millions of dollars onshore and tens of millions of dollars offshore. However, there is barely sufficient data to estimate the mean cost for either setting, or to establish the statistical likelihood of a successful intervention. The challenging lack of data in the public domain on known interventions prompted us to canvas domain experts with many decades of combined experience, and, in some cases, direct experience of the storage demonstrations and pilots with known well interventions outlined below (Table 4).

Table 4
Eleven GCS projects with known well interventions and availability of cost data.

Project	Country	Year	Intervention Required	Costs
Sleipner	NOR	1996	Injection well intervention to improve flow circa 1996	No
Weyburn	CAN	2000	Many routine well interventions to manage EOR flood	No
In Salah	DZA	2004	All CO_2 wells permanently suspended from 2011	No
Ketzin	DEU	2008	Monitoring well intervention to observe casing in 2015	No
Otway	AUS	2008	Monitoring well interventions in 2017 and 2024	Yes
Snøhvit	NOR	2008	Injection well intervention to change injection interval 2011	No
Decatur	USA	2011	Legacy well and monitoring well interventions 2024	Yes
Goldeneye	GBR	N/A	Legacy well review and interventions costed 2012 to 2015	No
Quest	CAN	2015	Well program for identified legacy wells 2012 to 2015	No
Gorgon	AUS	2019	Water abstraction well interventions planned for 2025	No
Ruby	DNK	2030	Rødby-2 (1953) successfully re-entered and inspected 2025	No

In addition to the eleven projects listed above, six European projects have recently passed a final investment decision (FID): Aurora, Endurance, Greensand, Hamilton, Porthos, and Ravenna. These offshore projects will have submitted detailed and costed plans for legacy well intervention programs. Presumably, the legacy well counts for the depleted hydrocarbon fields – Greensand, Hamilton, Porthos, and Ravenna – are much higher than their saline aquifer counterparts. The cost estimates for the six projects are not in the public domain.

The USA has also recently seen thirteen onshore Class VI wells permitted circa 2024 – EPA (11) and North Dakota (2) – with over one hundred more permits under review. Many, if not all of these, will have submitted costed legacy well intervention programs for their areas of review (AoR). The costs are redacted in the public documentation.

The dearth of cost data in the public domain partly reflects a lack of experience but also an unwillingness to share the little data available—legacy well costs are a sensitive issue for operators. However, recent studies on hydrocarbon legacy well remediation shed some light. For legacy wells in general, the average cost for simply plugging an onshore well in the USA has been reported as \$20k (Raimi et al., 2021). The same study, based on 19,500 wells across four US states, found that the average cost for plugging and surface reclamation was \$76,000; the P10 for the study was \$160,000 per well in 2019. Costs more than \$1 M were rare, with outliers reported at \$1.6 M and \$2.2 M in Texas. Haden Chomphosy et al. (2021) estimated a similar average cost of \$49,000 per legacy well for the USA. For known GCS project data – Decatur, USA and Otway, Australia – onshore costs were consistently \$1M-\$2 M, suggesting that, on the little evidence available, CO_2 legacy well interventions tend to be at the upper end of the cost curve. Taking \$50,000 as a low value and \$1.5 M as a high value, a logarithmic mean for onshore wells might be around \$275k. This is purely speculative.

Offshore costs are much higher. The highest cost for a legacy well intervention in the North Sea was estimated to be around \$50 million, with an expectation of several million dollars per well. This reflects rig hire rates that can exceed \$250k per day and is supported by cost data from Offshore Energies UK for recent decommissioning on the UK Continental Shelf (Offshore Energies UK, 2022) (Fig. 8).

Some further North Sea context is provided by the Norwegian Gyda oil field which was studied as a potential GCS site by Albrigtsen (2015). The thirty-year old field was decommissioned from 2020 to 2025 at an estimated cost of \$624 M, including the permanent abandonment of 32 wells. However, discrete costs for the well abandonment operations are not available. *Offshore Energies UK* estimated that wells account for 48% of North Sea decommissioning costs, followed by topside and subsea infrastructure removal (Offshore Energies UK, 2022). Applying that metric to Gyda, the average decommissioning cost would be \$9 M per well.

Assuming an order of magnitude distribution and slightly higher cost profile for GCS wells, the costs for offshore interventions might be \$5 M to \$50 M, with a logarithmic mean of around \$15 M per well. These estimates are again purely speculative. Furthermore, there are planned interventions and crisis response interventions, routine and ongoing monitoring interventions, and site closure interventions, all with distinct cost profiles. There is no single indicative price for a legacy well intervention, with costs being specific to the site and the well. Generalizations are unlikely to be helpful.

It is tempting, in the absence of data, to borrow assumptions from the much larger domain of oil and gas field operations, especially CO_2-EOR operations with their long history of legacy well management (Chukwuemeka et al., 2023; Hannis et al., 2017; Whittaker et al., 2011). Studied onshore EOR legacy well populations date back to the 1940s—for example, the SACROC site with over 1000 legacy wells in an 80 square mile area had no evidence of leakage. SACROC is known to have been actively managed for legacy well workovers and maintenance as needed, however these costs are not known.

Offshore, hydrocarbon well interventions are a common aspect of field management and decommissioning, as illustrated by the Gyda field

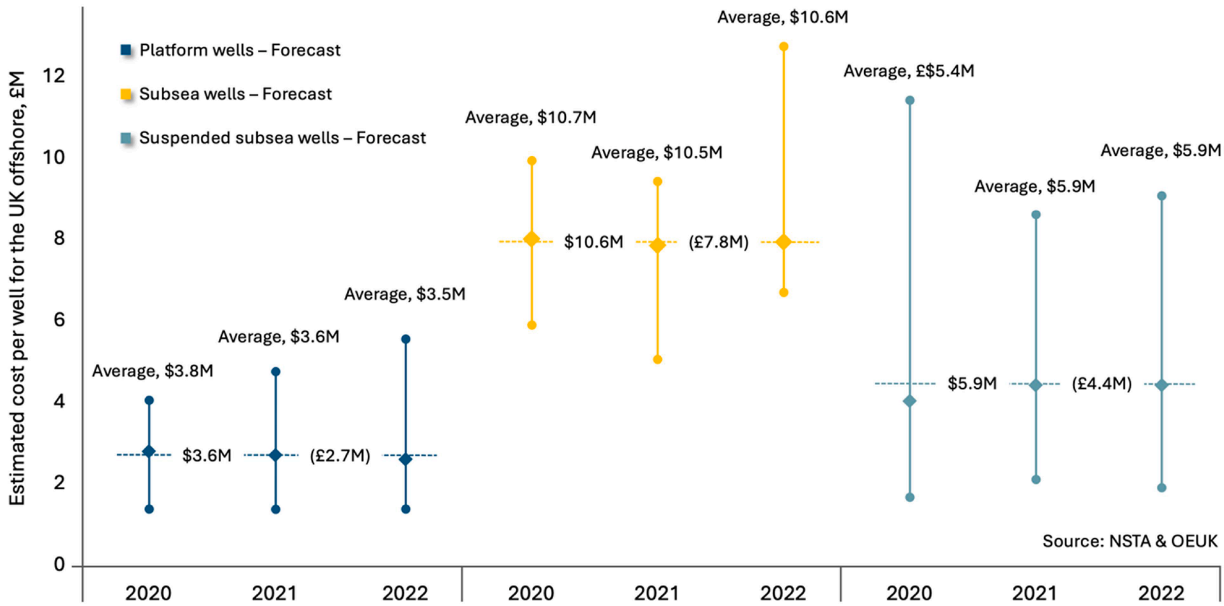

Fig. 8. Offshore well decommissioning costs for the United Kingdom. (Adapted from: Offshore Energies UK 2022).

example. However, discrete costs for well abandonment operations are not routinely available. A known issue when attempting to draw parallels between common practice for oil and gas operations, such as well abandonment, and CO_2 storage, is that the cost of legacy well management and abandonment is frequently obscured by various financial instruments including internalized cost offsetting and tax exemptions relating to the various stages of field development, management, and decommissioning of hydrocarbon fields (Ho et al., 2016). The estimation of costs for CO_2-EOR legacy well interventions is not straightforward nor necessarily indicative of intervention costs for GCS sites. At present, the general indication is that legacy well remediation costs are expensive and uncertain (Fig. 9). Given this, even a small number of legacy wells are likely to exclude prospective storage areas from serious consideration unless the wells are thoroughly documented and in good condition.

6. Future direction and research needs

Over the past ten years, the collective understanding of legacy well integrity, risks, and effective methods for managing those risks at geologic carbon storage (GCS) sites have advanced substantially. This progress came through growing efforts to characterize emissions from abandoned oil and gas wells, a continued focus of the research community on the performance of well materials under CO_2 storage conditions, and the practical experiences gained from the implementation of GCS at brownfield sites.

Field observations of well integrity and leakage show that oil and gas wells develop integrity issues over a wider range than previously reported due to several factors including well condition and local geology. Emissions from abandoned wells are probabilistic in nature, span several orders of magnitude, and are controlled by the characteristics of leakage pathways and near-surface modulation. Future research should focus on directly testing and refining the analogue relationship between methane and CO_2 leakage from legacy wells. While methane emissions provide a valuable empirical basis for assessing containment behavior, key uncertainties remain about how faithfully they represent CO_2 migration. Comparative field experiments that expose identical wellbore and near-surface systems to both gases are needed to quantify differences in transmissivity, phase behavior, and reactive alteration. Sustained multi-seasonal monitoring would also clarify the persistence and intermittency of leakage and its modulation by environmental drivers. Further work is required to quantify detection thresholds, reconcile surface-flux and

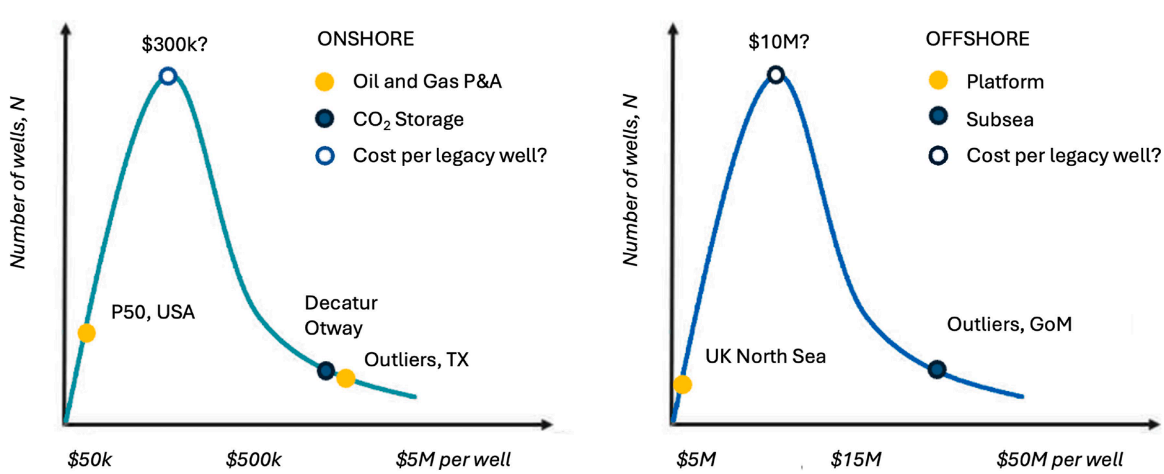

Fig. 9. The approximate cost of legacy well interventions for onshore and offshore projects based on scant data.

downhole indicators, and build harmonized statistical datasets that link well attributes with leakage probability and magnitude. Targeted offshore investigations and benchmarking of analogue predictions against emerging GCS-monitoring results will ultimately determine how transferable these methane-based analogues are to CO_2 containment scenarios and will strengthen the empirical foundation for future risk assessment.

Well materials research has constrained the conditions under which Portland cement exhibits self-sealing and non-sealing behavior in the presence of CO_2-rich fluids. However, characteristics of the leakage pathway and CO_2 phase in contact with the wellbore will impact the rate and extent of reaction. Initial experiments with humid CO_2 show a reduction in reactivity, which reduces leaching and associated degradation effects but simultaneously may reduce self-sealing potential. The presence of impurities such as H_2S can also alter cement carbonation. Chemical alteration has been shown to significantly impact the mechanical properties of cement, which can influence both the development of defects and their subsequent evolution as potential leakage pathways. Collectively, well material research findings continue to emphasize that focusing on chemical reactivity alone without considering the full hydrodynamical, mechanical and geometrical context can lead one to draw incorrect conclusions, which has been previously noted by Zhang and Bachu (2011), Carroll et al. (2016), and especially Carey (2013) in their reviews on the subject. Despite this, studies continue to refer to CO_2-induced reactions as "degradation" or "attack" without defining these terms or thoroughly addressing the impact or significance of observed reaction effects on zonal isolation integrity at the well scale. Future research should continue exploring the interplay between chemical reactions and hydrodynamical and geomechanical factors. Lab studies should expose well cement in representative geometries, under a realistic stress state and temperature, to a variety of CO_2-rich fluids that capture the range of compositions (including impurities) expected in the field. Numerical studies should evaluate the significance of observed reaction effects by modelling their impact on mechanical and hydraulic integrity at the well-isolation scale. These intimately coupled reaction-transport-mechanical processes ultimately impact cement susceptibility to defect formation, which can drastically change the hydrodynamic conditions along the well. Further work on methods for upscaling reactive transport models that simulate chemical reactions observed in the laboratory to wellbore dimensions is also needed.

New legacy well risk management workflows have been proposed that integrate many elements of legacy well risk assessment research with economic and regulatory constraints to determine the need and feasibility of mitigative actions. These workflows include the location, integrity characterization, screening, risk assessment, and risk mitigation of legacy wells. Technological advances in unmanned aircraft systems, machine learning, and artificial intelligence have reduced the costs of legacy well finding and well record digitization to facilitate well location and characterization; however, the inaccessibility (i.e., non-public) or lack of historic well records remains a major barrier in some regions. Researchers have begun developing non-invasive methods for legacy well integrity assessment, but more work is needed to make non-invasive tools valuable in the field. Multiple systems have been developed to evaluate and rank wells based on their construction, which are valuable for well screening. Screening methods based on scores predicted with high-level well attributes remain speculative but may be useful for regional evaluations where detailed well data are unavailable. Legacy well risk assessment research has predominantly focused on GCS site performance models—a quantitative method. Wide application of the NRAP Open-IAM, a flagship GCS risk assessment tool developed by the U.S. Department of Energy, has enhanced its capabilities for legacy well simulation but gaps remain in the software for site permitting applications. The probabilistic approach used by most GCS site performance models also does not quantify the risks of leakage through multiple relevant well leakage mechanisms. Case studies that include detailed scenario-based modeling of well leakage mechanisms relevant to specific GCS projects would be valuable. Risk mitigation research has focused on advancing annular cement remediation technologies that have the potential to increase the success rate of cement squeeze jobs and other operations that may be needed to ensure zonal isolation along legacy wells. However, deployment of these technologies requires well access, which remains challenging and expensive for abandoned wells, particularly offshore. Natural risk mitigation factors such as shale creep have the potential to close leakage pathways along legacy wells and reduce the need for well intervention—the timeline over which the creep behavior of different shales occur and their ability to seal wells under CO_2 storage conditions are not well understood and would be valuable subjects of future research.

Larger questions also remain about acceptable tolerances for legacy well leakage risk and leakage rates in regulated settings. Intervention is expensive and may be impossible for some legacy wells. The risk reduction gained through well remediation may be negligible when weighed against intervention costs. Additionally, as observed by Torsæter et al. (2024), the leakage risks associated with legacy wells can never be fully eliminated. Thus, regulatory tolerances for legacy well leakage risk will determine the feasibility of many GCS projects. While risk frameworks such as ALARP allow for cost-benefit analysis, NSR and the non-risk approach used in the U.S. Class VI rule do not permit such comparisons. Regulations are also not prescriptive when it comes to acceptable leakage rates. The Northern Lights and Sleipner projects use 50 kg m^{-2} day^{-1} of CO_2 as leakage thresholds to trigger investigation. Assuming a single point source occurrence at a legacy well, the leakage rate sums to just under 20 tonnes per year. For a commercial project like Northern Lights, storing hundreds of millions of tonnes of CO_2, this effectively implies that the containment expectation is 99.99%. Compare this to the quite common expectation of 90% capture for industrial carbon management projects. Further cooperation between regulators, operators, and researchers is needed to define acceptable tolerances for legacy well leakage to ensure the societal benefit of GCS.

CRediT authorship contribution statement

Greg Lackey: Writing – review & editing, Writing – original draft, Visualization, Validation, Methodology, Investigation, Formal analysis, Conceptualization. **Timotheus K.T. Wolterbeek:** Writing – review & editing, Writing – original draft, Visualization, Validation, Investigation, Formal analysis, Conceptualization. **Aaron Cahill:** Writing – review & editing, Writing – original draft, Visualization, Validation, Investigation, Formal analysis. **Andrew Cavanagh:** Writing – review & editing, Writing – original draft, Visualization, Investigation, Formal analysis. **Al Moghadam:** Writing – review & editing, Writing – original draft, Visualization, Investigation, Formal analysis. **Jaisree Iyer:** Writing – review & editing, Writing – original draft, Investigation. **Preston Jordan:** Writing – review & editing, Writing – original draft, Investigation, Data curation. **Rajesh Pawar:** Writing – review & editing, Writing – original draft, Investigation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.ijggc.2026.104604.

Data availability

No data was used for the research described in the article.

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